EAST PERTH AND CENTRAL BUSINESS DISTRICT NETWORK DEVELOPMENT STRATEGY

Review of Planning Philosophies

Revision 2 – Draft Final

August 2012

SINCLAIR KNIGHT MERZ

Foreword

This document provides a 25 year strategy for the development of the Western Power Network within the CBD Load Area. Where required, commercially sensitive information has been redacted from this publically available form of the strategy document at the request of Western Power.

References made to the development of sites are provided for the purposes of the strategy only, final decisions have not been made on specific projects and land requirements. Extensive stakeholder engagement will be sought by Western Power with regards to potential new developments and more detailed analysis will be undertaken by Western Power before investment decisions are made.

Contents

Figures

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document. International System of Units (SI) have not been included.

Table 1 Abbreviations and Acronyms

Abbreviation or Acronym	Full Name
AIS	Air Insulated Switchgear
CCTV	Closed Circuit Television
CML	Customer Minutes Lost
DM	Demand Management
DNSP	Distribution Network Service Provider
DTC	Distribution Transfer Capacity
EENS	Expected Energy Not-Served
EHV	Extra High Voltage
ENAC	Electrical Network Access Code (2004)
FACTS	Flexible AC Transmission System
GIS	Gas Insulated Switchgear
IMO	Independent Market Operator
HDD	Horizontal Directional Drilling
HILP	High Impact Low Probability
HV	High Voltage
JPT	Joint Planning Team
LTER	Long Term Emergency Rating
LV	Low Voltage
MV	Medium Voltage
NCR	Normal Cyclic Rating
NFIT	New Facilities Investment Test
NMP	Western Power Network Management Plan
Perth CBD Boundary	As defined in the Technical Rules, the present Perth CBD Boundary includes the geographical area in the City of Perth bound by Hill Street (East), Havelock Street (West), Wellington Street (North) and Riverside Drive and Kings Park Road (South) and supplied (exclusively or in part) from the following zone substations: Hay Street, Milligan Street, Wellington Street, Cook Street and Forrest Avenue
RRST	Rapid Response Spare Transformer
SKM	Sinclair Knight Merz
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWIN	South West Interconnected Network
SWIS	South West Interconnected System
TNDP	10 Year Transmission Network Development Plan
TNSP	Transmission Network Service Provider
VoLL	Value of Lost Load

Abbreviation or Acronym	Full Name
WACA	Western Australian Cricket Association
WEM	Wholesale Energy Market

Table 2 Western Power Substation Abbreviations

Abbreviation	Substation
BEL	Belmont
BTY	Bentley
CK	Cook Street
CT	Cannington Terminal
CTE	Cottesloe
EP	East Perth
F	Forrest Avenue
GLT	Guildford Terminal
HAY	Hay Street
JTE	Joel Terrace
MIL	Milligan Street
MLA	Mount Lawley
NP	North Perth
NT	Northern Terminal
ST	Southern Terminal
SUM	Summers Street
W	Wellington Street
WT	Western Terminal

Executive Summary

Western Power has identified the requirement for a robust long term development plan for the electrical transmission system assets in the East Perth and Central Business District (CBD) Load Area spanning a period of 25 years[1]. The plan is required to guide network development decisions along a clear, economically sound investment path and underpin future New Facilities Investment Test (NFIT) submissions to the Economic Regulation Authority (ERA) of Western Australia.

SKM was engaged by Western Power to assess potential long term development strategies for the CBD Load Area over a 25 year period, giving specific consideration to a range of network investment drivers including:

- Network reinforcement to accommodate area load growth over 25 years
- Asset replacement to address age and condition related deterioration
- Rationalisation of existing substation sites
- Specific customer driven connection works
- Overcoming practical limitations such as cable exit congestion
- Flexibility in future growth and expansion

In order to accomplish a full review of the existing network architecture and develop a longer term strategy for the CBD Load Area, three clear objectives were identified. These objectives included the following:

1) Provide advice regarding various planning philosophies currently adopted by Western Power
2) Development of a robust long term development strategy for the transmission system supplying the study area across a 25 year horizon
3) Development of a robust long term development strategy for the transmission system within the study area, including substation capacity reinforcement requirements, across a 25 year horizon

This report focuses on the current Western Power planning philosophy to provide advice on transmission and distribution network expansion for the CBD Load Area. It is the intention of this report to provide a comparison of the Perth CBD Boundary to other major cities giving consideration to reliability standards, transmission and distribution network architectures and distribution network installation techniques. An assessment of emerging and enabling technologies has also been provided. This report will serve to guide planning decisions for the development of long term strategies for the transmission system supplying and within the CBD Load Area.

---

[1] For simplicity this is referred to only as the CBD Load Area within this report.

Reliability Standards

The following summarises the findings after reviewing the existing reliability standards for the Perth CBD Boundary:

- The existing Perth CBD Boundary was developed in recognition of the economic importance of loads located in this small area (such as the Australian Stock Exchange) to the conduct of business throughout the state.
- Historically there have been few incidents and limited customer complaints based on the reliability standards that currently apply for the Perth CBD Boundary.
- By comparison to other major cities in Australia and worldwide, an allowable interruption of supply for 30 seconds at the transmission level under a single contingency event is quite lenient.
- Due to the present Western Power standard transformer design, the 11 kV busbars are not able to be operated in an interconnected (solid) state for fault reasons, resulting in some switching time to restore load during a contingency.
- The existing N-2 Perth CBD Boundary transmission criterion, with an allowable interruption to supply for two hours for an N-2 contingency, is comparable to many other standard planning practices.
- At a distribution level, some Australian CBDs afford a higher level of reliability than the existing network in Perth CBD Boundary, though not without significant network investment such as additional distribution transformers or supplies.
- Whilst Western Power no longer plans for HILP events as part of its current Transmission Planning Criteria, the current planning practices employed to achieve N-2 have resulted in a DTC network capable of providing full back up to the substations within the Perth CBD Boundary.

Further analysis in this area has yielded a number of recommendations for the existing reliability criteria within the CBD Load Area. The recommendations are as follows:

1) It is not recommended to expand the Perth CBD Boundary beyond that defined in the Technical Rules in the short term. Western Power should continue to monitor the load density as new establishments are developed and periodically review the boundary.
2) Any new CBD Load Area substation developments outside the present Perth CBD Boundary should be planned initially for bumpless N-1 (i.e. no interruption to supply during a contingency event) with a view to ultimately providing for N-2. As this would require a change to the Technical Rules, the wider impact on those substations affected by the change as compliance must be maintained at those sites.
3) Conversion of the existing Perth CBD Boundary substations from the current N-1 criterion to a bumpless or reduced interruption time arrangement should be undertaken where opportunities exist to achieve this at a marginal additional cost.
4) The additional investment required to support a HILP event within the Perth CBD Boundary to above what is required to maintain N-2 security should be calculated and the positive net

benefit assessed using probabilistic methods. Alternatively, the installation of fire fighting systems to limit fire damage, CCTV surveillance systems and other such measures are recommended to reduce the risk and potential outage time.

5) It is recommended to continue to install some DTC between substations sites, where opportunities exist, to facilitate rotational load shedding techniques, if necessary.

It is recognised the existing network has developed under the planning philosophies to date. Given this, a review of the existing assets provides clear guidance on the benefits and shortcomings of existing philosophies. To this end, a review of the existing distribution and transmission network architecture has been undertaken.

Distribution Network Architecture

The existing Western Power distribution network within the CBD Load Area was assessed against known limitations. The following summarises the findings of this report:

- A number of limitations exist on the distribution network within the Perth CBD Boundary including existing cable congestion at substation exit points and limitations on new cable routes within the Perth CBD Boundary. If the cable congestion issues are not addressed in the near term, the continued use of 11 kV to connect new load within the Perth CBD Boundary, with existing equipment specifications, will not be economically appropriate moving forward.
- The existing network already has a notable percentage of equipment rated for 22 kV operation, currently operated at 11 kV.
- Distribution feeders within the Perth CBD Boundary are restricted to 50% utilisation to ensure N-2 support; this has resulted in a large number of cables required to supply the load demand.
- The use of some DTC was found to be beneficial in providing support to neighbouring zone substations, but further exacerbates the cable congestion issues presently seen on the network.

Analysis of various options to address the limitations was performed on a greenfield basis initially. Idealised models were created which were then used to guide the development of more targeted network strategies for the actual network. The following recommendations are made:

6) To utilise the maximum amount of transformer capacity within the Perth CBD Boundary, the distribution planning practice of limiting cable utilisation to 50% should be reviewed with a view to increasing utilisation in the short term to facilitate further load connections.

7) Thermal rating calculations should be undertaken to appropriately rate equipment, ensure maximum utilisation of existing assets and reduce the need for the installation of additional feeders in an already congested network.

8) A holistic assessment of distribution operating voltages demonstrates migrating substations within the CBD Load Area to 22 kV as attractive, unless otherwise required to retain 11 kV. Generic analysis also demonstrates a staged migration on an as-required basis to be preferred as savings in the order of $17.5M may be realised (depending on approximate timing for equipment replacement). This would require 22 kV equipment to be installed, but initially operated at 11 kV, until such time as the CBD Load Area is fully converted. It is recommended

to further investigate this option to better understand the impact on cost benefit and cable congestion.

9) Generic analysis of the distribution network supporting N-2 compliance demonstrates the benefits in installing a combination of some DTC and a transmission interconnection. It is recommended to investigate this further for application to substations within the Perth CBD Boundary.

Transmission Network Architecture

A review has been conducted of the existing Western Power transmission system in the vicinity of the CBD Load Area. From this, a number of observations can be made:

- The existing transmission system supplying the CBD Load Area is a highly meshed 132 kV network, emanating from a number of external 330 kV bulk supply points. The current architecture results in numerous interdependencies between northern and southern networks supplying the CBD Load Area, and is sensitive to generation dispatch conditions. This leads to considerable challenges to plan and operate the network.
- The existing 66 kV network infrastructure in the CBD Load Area has reached the end of its service life.
- The cost premium for moving to 132 kV is now considered negligible.
- There is little need for a higher voltage than 132 kV at the present time or within the short to medium term.

Further analysis was undertaken on a brownfield basis to provide recommendations for the continued development of the transmission network:

10) Analysis shows a number of benefits in removing the 66 kV assets in the CBD Load Area in favour of 132 kV assets. It is recommended to replace these assets are at the end of their economic life with supplies rationalised into a smaller number of larger 132 kV substation sites.

11) Migrating to a transmission system voltage higher than 132 kV (330 kV) should be considered once the CBD Load Area demand reaches circa 700-800 MW, anticipated to be around 2030 to 2035. This timeframe will also present an opportunity to rationalise the CBD Load Area supplies.

12) Suitable locations for potential 330 kV terminal substations in the vicinity of the CBD Load Area should be identified in the short term.

13) The potential to construct higher capacity new 132 kV transmission lines in whole or part to 330 kV specification to facilitate future upgrades should also be considered.

Emerging and Enabling Technologies

Finally, emerging and enabling technologies were assessed for implementation within the CBD Load Area. The following summarises the findings of this report:

- A review of installing a pit and duct system versus a cable tunnel concluded that a pit and duct system would be more economically attractive, though limited by the number of cables that could be installed.
- Installation of a cable tunnel would allow for a combined transmission and distribution system and potentially accommodate other services.
- DM techniques were presented and reviewed as part of this study recognising they are unlikely to prove a substitute for traditional network capacity and asset investment. These techniques can, however, improve the spend curve by delaying investment for a period of time.
- Self healing distribution networks were briefly discussed including the advantages that implementation of such a network may bring to reliability or performance.
- Due to the geographical location of the CBD Load Area, future connections that require crossing the Swan River may require the use of alternative techniques such as subsea cabling or horizontal direct drilling (HDD) techniques.

Thorough review of documentation provided along with further analysis yields the following recommendations:

14) It is recommended to further investigate project specific issues alongside longer term strategic area plans to determine the extent to which pit and duct could be employed across the Perth CBD Boundary and to identify areas where a cable tunnel may be more efficient.
15) The use of GIS equipment should be considered for any future zone substations within the CBD Load Area.

The findings of this report should be incorporated into the long term strategy developed for the CBD Load Area.

1. Scope of Assessment

1.1. Background

Western Power has identified the requirement for a robust and documented strategy for future network development in the CBD Load Area across a 25 year outlook. Whilst considerable work has been done on this in the past, a need for a holistic review of the status of the network recognising recent load trends, asset condition, technology improvements and other broader strategic network drivers and business objectives has been recognised.

The absence of a refreshed strategy continues to present uncertainty for Western Power when making capital investment decisions for new installations, customer relocations and ongoing maintenance activity. A robust network development strategy also reduces regulatory risk and increases the likelihood that new facilitates will meet the NFIT requirements as stipulated by the ERA of Western Australia [2].

Western Power has recognised the urgency for a refreshed strategic network development plan in the area to guide network engineering decisions along a clear, economically sound investment path and underpin future NFIT submissions. As part of its Transmission Network Development Plan (TNDP) Western Power has identified a number of emerging limitations in the CBD Load Area. Whilst the TNDP presents a good view of these emerging constraints, its focus on the CBD Load Area was not sufficiently mature to consider a detailed and more optimised assessment of asset condition and capacity related emerging constraints, particularly across a 25 year horizon. Western Power identified further work is required to form a robust economic development proposal to address the emerging constraints and prepare a suitably staged program of work to ensure deliverability and mitigate risk.

It is the purpose of this report to undertake a review of the existing planning philosophies implemented by Western Power. This review will provide advice on transmission and distribution network expansion for the CBD Load Area. It is the intention of this report to provide a comparison of the CBD Load Area to other major cities giving consideration to reliability standards, transmission and distribution network architectures and distribution network installation techniques. An assessment of emerging and enabling technologies will also be provided. This report will serve to guide planning decisions for the development of long term strategies for the transmission system supplying and within the CBD Load Area.

This report is in forms complementary to the SKM East Perth and CBD Load Area Development Report as part of the wider CBD Load Area network development strategy. The 'East Perth and CBD Load Area Development Report' examines both the transmission supply to the CBD Load Area and the long term strategy within the CBD Load Area over a 25 year horizon [3]. Both reports have been prepared in tandem with an overarching summary document identifying the conclusions and recommendations from both reports in brief.

1.2. Aim of Document

1.2.1. Study Scope of Work

As highlighted in the previous subsection, Western Power has identified the need for a refreshed long term network planning strategy for the CBD Load Area transmission supply. To address this issue, and support future NFIT submissions for new facilities to the ERA, SKM has been engaged by Western Power to develop a robust long term development strategy for a study horizon of 25 years.

The aim of this report is to provide advice regarding various planning philosophies employed by Western Power and identify if current practices are economically and technically sustainable. The findings in this report supplement and guide the approach taken in preparing the long term plans to ensure they are sufficiently flexible to accommodate changes in network usage patterns and load density and are consistent with good industry practice. As part of this report, the following elements will be assessed:

- Review of existing Western Power planning documentation
- Review of the existing N-2 Perth CBD Boundary
- Transmission network architectures
- Distribution network architectures
- Transmission reliance on distribution networks
- Distribution network installation methods
- Emerging and enabling technologies

At both the distribution and transmission network level, consideration has been given to architectures employed elsewhere in Australia and the world. These considerations include differences in operating voltage for distribution and transmission and the means by which other utilities provide security during contingency events. This study also highlights practices Western Power currently employs that are considered effective as well as limitations to the current operating and planning models.

1.2.2. Assumptions

In reviewing this study report it is important to understand not only the original aim of the work performed, but also how this work fits within the wider context of the development of the Western Power transmission system supplying the CBD Load Area. It is worth highlighting a number of key assumptions in this study. These include:

1) *Approximately 240 MVA of new load will materialise in the CBD in the next 25 years, based on estimates provided by System Forecasting [4].*

Understanding the amount of load in the CBD Load Area will help drive the analysis with respect to various discussions on operating voltage at both transmission and distribution level and energy density.

2) *In order to develop distribution network architecture options, a greenfield approach was taken (i.e. new construction with no physical constraints).*

A greenfield approach was taken to examine the distribution network taking into consideration the opportunities for new sites within the CBD Load Area over the study horizon. New sites would allow for opportunities to establish new distribution arrangements and provide added flexibility for interconnected options.

3) *Transmission network architecture options were developed on a brownfield basis, assuming "stitching in" of options into the existing network.*

The CBD Load Area consists of several transmission circuits that already exist and still have remaining service life. A brownfield approach was taken as these circuits will remain for the foreseeable future, making the transmission network less flexible in accommodating new topologies over the foreseeable future. Opportunities for reconfiguration are quite limited as few new circuits are expected to be required to provide supply to the CBD Load Area. This approach was agreed by the Joint Planning Team (JPT).

4) *11 kV cables have a maximum rating of 6 MVA[2] and 22 kV cables have a maximum rating of 12 MVA.*

An important part of this analysis is determining whether or not the existing network architecture will be able to support the growing load demand or if a fundamental shift is required. The shift may include a migration to a higher operating voltage, installing additional cables between existing sites, or establishing new zone substations. The current carrying capability of a distribution feeder will allow for a comparison to be conducted between the different voltage levels.

[2] This assumption does not consider various factors such as the impact of cable de-rating, which may severely restrict the current carrying capability of the distribution cable.

2. Reliability Standards and Planning Criteria

For the purposes of this network planning project, Western Power has formed a JPT consisting of representatives from the various sections of the company:

- Transmission Planning
- Distribution Planning
- Network Performance
- System Management
- Environment, Community and Approvals
- Standards, Policy and Data Quality
- Smart Grid Development

Regular meetings were held inviting these stakeholders to discuss the existing reliability criteria and any proposals to change them, such as an extension of the current Perth CBD Boundary, in addition to gathering information on historical events within the CBD Load Area and providing a forum for discussing project developments.

2.1. Current Criteria

The following discussion reviews the current contingency criteria for the CBD Load Area. It presents the findings of an overall, coordinated review of the transmission and distribution system architectures and how these, together with the Technical Rules, affect the reliability afforded to the CBD Load Area customers.

The review concentrates on contingency criteria only. Other aspects of planning criteria such as voltage limits, fault ratings, power factor and harmonics are beyond the scope of this report. Existing guidelines are available for these aspects and, while there is scope for review of some aspects for particular application within the CBD Load Area, it is not considered necessary at this stage.

This section presents current Western Power practices before introducing practices utilised in other major cities around Australia. A comparison of the various planning criteria is then made with a view to provide recommendations on existing criteria that can be improved, if any.

2.1.1. Definition of the Perth CBD Boundary

The present Perth CBD Boundary includes the geographical area in the City of Perth bound by Hill Street (East), Havelock Street (West), Wellington Street (North) and Riverside Drive and Kings Park Road (South) and supplied (exclusively or in part) from the following zone substations: Hay Street, Milligan Street, Wellington Street, Cook Street and Forrest Avenue [1]. The Perth CBD Boundary covers an area of approximately 1 km^2 and has an average load density within this area of approximately 170 MVA/km^2.

The Technical Rules are clear on the performance of the network under various operating conditions. The Perth CBD Boundary is an area of particular importance and has specific requirements. Section 2.5.3 of the Technical Rules defines the criteria by which the Perth CBD Boundary must be designed. The load within Perth CBD Boundary is of major economic importance to the conduct of business throughout the state. There must therefore be sufficient transfer capacity to ensure the continued supply of power to all consumers without the need to reschedule generation. This is a requirement for not only N-1 events, but also for N-2 events involving coincident outages of any two transmission elements, at peak demand. Furthermore, for a transmission element failure at Wellington Street Zone Substation resulting in the loss of supply to the site, any load supplied from Wellington Street located within the Perth CBD Boundary must have full backup. The architecture of the Western Power Network[3] currently allows for this through extensive use of DTC.

2.1.2. Description of Security/Reliability Terms

To appreciate typical electricity network planning criteria it is appropriate to have a clear understanding of the terms used in discussing security and reliability. The following provides a simple description of the terms to facilitate a discussion on the reliability criteria applied to the Western Power Network and a comparison with other utilities further below.

- **Table 3 Security/Reliability Terms**

Term	Description
N-0	Loss of a single transmission element (a line, transformer or other equipment) could cause a supply interruption to some customers.
N-1	The network can withstand the loss of any single transmission element and maintain supply to all customers.
N-1 secure	The network can withstand the loss of any element and maintain supply to all customers. In addition the network can be subsequently reconfigured to withstand a further outage. During the time taken to re-configure, the network is at risk.
N-1-1	The network can withstand coincident planned and unplanned outages of transmission elements at up to 80% of the peak transmission system load.
N-1-G	The network can withstand the worst case credible loss of one transmission element and a generator.
Modified N-2	The network can withstand the loss of a critical element together with the further loss of a non-critical element. This security standard has been applied to the Sydney CBD.
N-2	The network can withstand the loss of any 2 network elements and maintain supply to all customers. Very few networks have true N-2 security.

[3] Western Power is responsible for the Western Power Network which includes the shared transmission and distribution network within the SWIN. The SWIN refers to the network component of the SWIS, including small pockets of infrastructure Western Power does not own or manage. The SWIS refers to the entire system, including generators.

Term	Description
Normal Operating State (Section 3.3 WEM Amending Rules)	Term used in the Wholesale Electricity Market Amending Rules to describe a power system that is able to provide electricity in a stable manner and within the prescribed technical envelope (voltage, frequency, fault levels, ratings, etc). In such a network state, System Management must not take any actions that in its opinion would lead to a High Risk Operating State.
High Risk Operating State (Section 3.4 WEM Amending Rules)	Term used in the Wholesale Electricity Market Amending Rules to describe a power system that is in violation of any requirements of the Normal Operating State for a period of fifteen minutes or more including; a violation of the Spinning Reserve requirements, insufficient Load Following range, a voltage deviation of greater than ±6%, a frequency deviation of greater than ±0.12 Hz, a transmission line is overloaded but the overload can be managed, etc. In such a network state, System Management may take any actions it considers are required to return the SWIS to a Normal Operating State.
Emergency Operating State (Section 3.5 WEM Amending Rules)	Term used in the Wholesale Electricity Market Amending Rules to describe a power system that is in violation of any requirements of the Normal Operating State for a period of fifteen minutes or more including; a frequency deviation of greater than ±0.5 Hz for more than five minutes, a voltage deviation of greater than ±10% for more than five minutes, circuit currents exceed hard circuit ratings, etc. In such a network state, System Management may; direct any Rule Participant to provide Ancillary services, utilise the overload capacity of Scheduled Generators, cancel or defer Planning Outages, take other such actions as required to restore the SWIS to a Normal Operating State.

2.1.3. Technical Rules

The Western Power Technical Rules [1], as endorsed by the ERA, provide guidance on the minimum level of security and quality of supply the Western Power transmission and distribution networks must provide in various parts of the system. This section discusses the requirements of the Western Power Network under different operating conditions at both the transmission and distribution level.

2.1.3.1. Transmission System

Various measures exist that dictate the supply required at the transmission level for different operating criteria; mainly N-1 and N-1-1. Section 2.5.2 of the Technical Rules provides further detail on the minimum level of security and quality of supply the transmission system must provide [1].

The N-1 planning criterion may be applied to any sub-network within the Western Power Network, with the exception of zone substations designed to the N-0 criterion[4], the 1% risk or NCR criteria, and states that supply must be maintained at any load level for any generation schedule following the loss of a single transmission element [1]. An exception to this rule, as stated in clause 2.5.2.2 (d) of the Technical Rules, is the failure of a zone substation supply transformer. This contingency event may result in loss of supply for a brief switching period while loads are transferred to un-faulted supply transformers by means of distribution system switching.

Section 2.5.2.3 of the Technical Rules describes the N-1-1 criterion, applicable to those sub-networks where the occurrence of a credible contingency during planned maintenance of another transmission element would otherwise result in loss of supply to a large number of consumers [1]. This criterion is applicable to 330 kV lines, 132 kV terminal stations in the Perth metropolitan area, Muja 132 kV power station and 132 kV transmission lines that supply a sub-system comprising more than 5 zone substations with total peak load exceeding 400 MVA and all power stations whose total rated export exceeds 600 MW. Table 2.9 in the Technical Rules lists maintenance outages and contingencies which are allowable in accordance with the N-1-1 criterion. Under the N-1-1 criterion, each sub-network must be able to continue to supply at least 80% of peak load.

Application to the CBD Load Area

Under N-1 operating conditions, there may be an interruption to supply for up to 30 seconds to allow loads to be transferred to other supply transformers at the substation. However, 100% of supply must resume as normal after 30 seconds within the Perth CBD Boundary. Similarly, for an N-2 contingency event, defined within the Perth CBD Boundary only, interruption to supply for up to 2 hours is allowed while load is transferred to other supply transformers at the substation or to alternative substations. In comparison to other load areas within the Western Power Network, the additional N-2 requirement for the Perth CBD Boundary drives a much more reliable network.

Zone Substations

In addition to the N-1 requirements zone substations may be classified using one of two criteria as defined in the Technical Rules; the 1% Risk criterion and the NCR Criterion [1]. No zone substations within the Perth metropolitan area may apply the 1% Risk Criterion. The NCR criterion allows for loss of a portion of the demand; the lesser of 75% of the smallest transformer at the substation or 90% of the capacity of the RRST for a period of up to 12 hours. This criterion may be applied to the Perth metropolitan area. North Perth Zone Substation is classified as an NCR substation.

Given the requirement for supply to be restored within 30 seconds of a single credible contingency within the CBD Load Area, the application of the NCR criteria cannot apply. This is due to the

---

[4] A substation is permitted to be designed to the N-0 criterion if the peak load at the site is less than 10 MVA. Similarly, sub-networks with a peak load of less than 20 MVA are also permitted to be designed to N-0.

associated time to restore power via an RRST, which is significantly more than 30 seconds, especially if an RRST is not already present at the site. It should also be noted most of the existing substations in the CBD Load Area are classified as N-1 substations.

2.1.3.2. Distribution System

As per Section 2.5.4 of the Technical Rules, the HV distribution network needs to be designed and operated only to the N-0 criterion. Enhanced security of supply may be negotiated with users; however no obligation exists for Western Power to offer this higher level of reliability [1]. The rules are more stringent for distribution feeders within the Perth CBD Boundary, requiring the feeders to be designed for remotely controlled switching to enable restoration of supply in the event of an unplanned loss of supply due to the failure of a single piece of equipment on an HV distribution system. Similarly, the LV distribution network is designed to the N-0 criterion, however interconnection between low voltage feeders may be provided where technically and commercially feasible to offer higher levels of reliability.

The current Perth CBD Boundary contingency criteria are met by utilising DTC. Due to the interconnected nature of the zone substations within the CBD Load Area, enough transfer capacity exists to ensure continued supply through the distribution network. The current practice within the Perth CBD Boundary is to install two 11 kV feeders, creating a feeder pair, with a normally open point between them and utilise the cables no more than 50%. This leads to a very congested 11 kV network as a large number of cables are required to back up the zone substations. As there is currently limited space for future expansion of the DTC, consideration must be given to alternative solutions to develop the network to cater for continuing load growth.

2.1.4. Planning Guidelines

In addition to the Western Power Technical Rules, Western Power has established planning guidelines for both the transmission and distribution networks [5], [7]. While the Technical Rules provide the performance standards that are the basis for planning studies the planning guidelines serve to identify a methodology for network planning solutions that meet the requirements of the Technical Rules, as well as providing an interpretation of the Technical Rules where necessary. The Transmission Planning Guidelines and the CBD Distribution Planning Guidelines are discussed in more detail in Sections 2.1.4.1 and 2.1.4.2, respectively.

2.1.4.1. Transmission Planning Guidelines

Three main system performance criteria exist that can be ranked by order of importance for network planning studies; system security, reliability and quality of supply [5]. These criteria are interrelated with system security presenting as a higher priority given the potential for widespread power system failure and blackout should it not be maintained. System reliability and quality of supply are generally associated with more localised parts of a network. These main performance criteria must be met for credible load and generation scenarios in order to provide justification for network augmentation.

The Transmission Planning Guidelines refer to various sections of the Technical Rules and how to apply these rules to network planning. The different sections of the guidelines of particular importance to long term planning are as follows:

- Voltage (limits) - defines the operating envelope the transmission system must operate within (±10% of nominal voltage)
- Power Transfer Limits - indicates the ability to transmit power around the various parts of the network determined from simulation studies
- Contingency Criteria - the level of security that must be afforded to the network under various network outage conditions
- Fault Currents - ensures the network is designed and operated safely with no uncurtailed increase in fault levels

The planning guidelines state that the network must be able to maintain supply in accordance with the contingency criteria defined in the Technical Rules, as discussed in Section 2.1.3.1. The guidelines are an interpretation of the Technical Rules, as viewed by Western Power, for the avoidance of any doubt.

Application to the Perth CBD Boundary

The Perth CBD Boundary requires a more rigorous level of security as discussed in Section 2.1.1; in particular Hay and Milligan Street Zone Substations. The transmission network within the Perth CBD Boundary must meet an N-2 level of security. This differs from N-1-1 required at terminal substations in that the full load must continue to be supplied without any re-dispatch of generation under the N-2 criterion, rather than 80% of peak demand, for a credible double contingency. It is important to make this distinction as any changes to the existing Perth CBD Boundary transmission network architecture must still comply with the N-2 criterion as well as the existing voltage, power transfer limits and fault current guidelines.

A comparison of the Perth CBD Boundary planning guidelines to practices employed by utilities in other major cities is presented in Section 2.3.

2.1.4.2. CBD Distribution Planning Guidelines

Similar to the Transmission Planning Guidelines, Western Power has developed planning guidelines for the distribution level, focussing specifically on the Perth CBD Boundary [7]. The planning guidelines indicate that the supply within the Perth CBD Boundary should be fully restored within 2 hours under an N-2 contingency, as indicated in the Technical Rules. The design of the substations supplying the Perth CBD Boundary lends itself to full restoration through the distribution network through the use of automated switching schemes, whereby the ring main units may be transferred between CBD Load Area substations to continue the supply. Due to the special needs of the Perth CBD Boundary customers, a group of specific supply contingency criteria have been adopted for this area as follows:

- Ten minute load restoration time for a distribution cable fault
- One hour load restoration time for an 11 kV switchgear bus section fault

- Two hour load restoration time for the loss of both front and rear bus sections in an 11 kV switchgear fault
- Two hour load restoration time for the complete loss of a zone substation

The above criteria were developed as part of System Management's Control Room Instruction 51-01, originating in 1997 and more recently revised in 2004 [6].

Thermal rating calculations need to be undertaken in order to determine the optimal rating of equipment. The distribution planning guidelines state that the Perth CBD Boundary loads are 'lumpy' and in a duct bank even loading of cables is difficult. Therefore, where a number of cables are more than 10% over a limit of 254 A, thermal studies should be undertaken to ensure the duct is not overloaded [7].

A number of other guidelines are adopted for planning the distribution network, though these are not as applicable for long term network planning. It should be noted, however, that these guidelines must be referred to whenever planning of the transmission and distribution systems occurs. Section 2.4 presents a comparison of the existing distribution criteria to which utilities in other major cities plan.

2.2. Evolution of Criteria

At the most basic level, legislative requirements are the minimum standards that must be met by Western Power when planning its electricity network. The Electricity Act is legally enforceable and as such has a penalty for non-compliance. The potential penalties are severe, including a worse case of loss of a license to transmit or distribute power.

Among the legislative requirements is the Technical Rules which have been developed as the electricity network has evolved. Historically, at the earliest times of the Perth CBD Boundary network there was no specific architecture philosophy other than to be able to restore supply due to the fault or maintenance of one transmission asset. The transmission system was adopted primarily to supply the load in the Perth CBD Boundary from a number of substations. A contingency criteria for the Perth CBD Boundary was first approved in August 1991 [8], however the main focus was on enhancements to the distribution network rather than the transmission network. These contingency criteria would eventually evolve into the Technical Code, published in 1997, the Interim Electricity Transmission Access Technical Code in 2004 and ultimately the Technical Rules as they are known today, first published in 2007[5].

The original contingency criteria indicate the decision to allow 100% of the load from one of the designated CBD Load Area substations, Hay Street or Milligan Street, to be transferred to the other via the 11 kV cable network was first approved by Western Power in the same year that the contingency criteria was established. It was decided that distribution cable system enhancements

---

[5] The Technical Rules were again updated on 23 December 2011 and are the Technical Rules currently used by Western Power.

would diminish the need to enhance incoming 132 kV circuits and eliminate extended outage periods. The remote control of distribution substations also allowed for fast switching and supply restoration leading to greatly improved customer service.

The contingency criteria adopted in 1991 allowed for a 2 hour outage in the event of two transmission circuit outages. A key to the success of this system was the automatic switching of switchgear and the communications infrastructure that would support this undertaking. The maintenance of these systems, therefore, also played a vital role in its success. An economic analysis demonstrated the ongoing costs of substation automation and maintenance was a less expensive option ($[redacted]) than transmission network augmentations ($[redacted]), further strengthening the argument to provide back up through the distribution network [8].

The eventual use of three low impedance, three-winding 132/11/11 kV transformers in each of the Hay or Milligan Street substations prevented the 11 kV bus-couplers from being run closed as this would otherwise result in fault levels above the design rating of the 11 kV switchgear. It is allowable for this to result in a loss of supply of up to 30 seconds under a single contingency to automatically switch the load to the healthy busbars.

In order to significantly improve the quality of service from an N-1 outage, two transformers would be required to supply each customer, with separate feeders to each, as well as a bus-coupler closed between the 415 V secondary windings for a loss of either to not be seen by the customer (demonstrated by the Triplex system as employed in the Sydney CBD, discussed in Section 2.4). This is what is commonly known as a bumpless system as it has no impact on the customer.

High Impact Low Probability (HILP) Events

The original contingency criteria established in August 1991 required the network to cater for the loss of a transmission substation up to a maximum load level of 144 MVA [8]. The criteria stated that an outage of 4 hours could be allowed in the event of the loss of a transmission substation due to a fire, explosion, etc. before the full load had to be restored. The repair time for this damage was estimated at up to 9 months. These factors helped drive the expansion of the distribution network to what is seen today, as full back up is provided by the DTC.

As the criteria have evolved into their present form as the Technical Rules, planning for HILP events is no longer required unless economically justifiable. It is important to keep this in mind as expansion of the distribution network no longer has to fully support the loss of a substation where the transmission network is not already capable of doing so.

2.2.1. Historical Incidents

In a JPT discussion on the incidence of contingency events in the CBD Load Area, a number of key points were made that could affect the way in which the network develops:

1) To date there have been fires which have resulted in the de-energisation of entire transmission substations. It was noted in one instance that the fire fighters required the de-energisation of the entire substation to fight the blaze, resulting in a prolonged outage until the substation could

be re-energised. However, these events occurred at substations outside of the Perth CBD Boundary and had no impact on the load within the Perth CBD Boundary[6].

2) There have been occasions where two circuits on the same pole have been de-energised to allow for high vehicle movement across a circuit path. To facilitate this planned action, the de-energisation was scheduled at times of low load demand and the load was then distributed to other CBD Load Area substations. Similarly, standby generators or rotated load shedding on non-Perth CBD Boundary feeders has also been used to ensure continuance of supply. This is due to only two circuits supplying each of the Hay Street or Milligan Street substations. However, as there is currently adequate DTC to support transferring the entire load to surrounding substations, no violations of the Technical Rules have occurred.

3) From meetings with the community there are no significant complaints attributable to the continuity of supply from any Perth CBD Boundary customers and nothing by way of litigation or public disclosure.

4) There have been a number of distribution cable faults within the Perth CBD Boundary owing to significant construction activity, but all of these have resulted in customers having their supply restored within the times allowed for by the Technical Rules. No major complaints have resulted from these faults.

5) The DTC is established by those cables which can be used to transfer the load from a failed substation to another. System Management personnel have indicated that transferring the entire load from one substation to the others is operationally challenging due to the way in which the distribution network has evolved since the nineties. There is some doubt as to whether or not this can be accomplished in practice.

In summary, customers have typically not seen any major inconveniences due to faults and have the assurance that they will have their load restored within two hours for two circuit faults feeding a zone substation. Those customers that see themselves as vulnerable to these 2 hour events have made allowance by means of their own emergency generators (50 MW worth estimated by the DSM department to-date). Should the outage duration extend beyond the 2 hour restoration time, it is assumed the quality of service would be seen as unacceptable by the customers, not to mention be in breach of the Technical Rules.

Consumers are entitled to enjoy the current additional service offering due to the existing distribution network configuration which provides full back up for loss of the Hay or Milligan Street substations. This may no longer be the case as the network develops as the Technical Rules do

---

[6] The event mentioned above refers to a fire at Wellington Street Zone Substation. The substation contains no fire detection or mitigation and only a single room of LV switchgear and protection equipment, all of which was lost in the fire. It should be noted Hay and Milligan Street have a high level of fire protection and automatic mitigation measures in place so de-energisation of the entire substation is highly unlikely.

not require planning for HILP events, as previously stated. It should be noted that while the network may not necessarily be planned for HILP events, mitigation measures will be taken where appropriate to limit events that could lead to the loss of an entire substation (such as installation of fire suppression systems, CCTV, etc.).

Information has been provided concerning various faults experienced on the network since mid-1993. A review has been conducted for both the transmission and distribution network, analysing the frequency and type (N-1 or N-2) of contingency event. Refer to Appendix F for a full table of contingency events at Hay and Milligan Street Substations.

In summary, the network has experienced seventy N-1 events on the transmission network within the Perth CBD Boundary since 1993, and three N-2 events that affected supply. Due to the present transformer-feeder configuration of the Hay and Milligan Street substations, loss of one of the 132 kV circuits supplying the site and one of the transformers is considered an N-1 event, although automated switching reconnects the non faulted element (transformer or circuit) within approximately 5 seconds leaving only the faulty element isolated.

There is only one reported double contingency event at Milligan Street Substation, occurring on 30th October 2009, which resulted in a loss of transformers T1 and T2. During this contingency, T1 tripped due to a feeder fault. Load was restored by transferring load from the faulty feeder to a healthy feeder. During a switching operation less than 1.5 hours later, T2 tripped before the load was restored at T1. Load was restored to both transformers within 2 hours of T2 tripping. Although T1 was out of service for more than 3 hours in total, the N-2 event occurred for less than 2 hours, thereby remaining compliant with the Technical Rules.

Hay Street Substation, on the other hand, has experienced two N-2 contingency events that resulted in the loss of two zone substation transformers; 29th June 1995 and 7th June 2001. In both instances the transformers were re-energised and the load was restored within two hours.

The distribution network has also experienced a number of N-1 contingency events. However, due to the current practice of loading feeders to no more than 50% of rated capacity, no loss of supply beyond the allowable timeframe has been experienced.

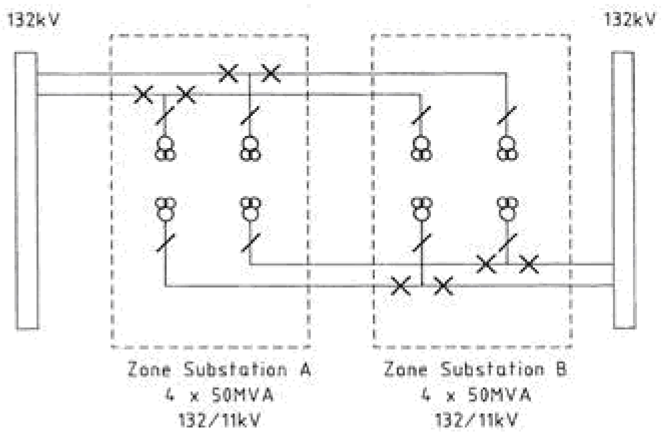
Discussions with the Western Power System Management team indicate a high degree of confidence to meet the Technical Rules requirement for an N-1 contingency event at Hay and Milligan Street. This is due to operating the substations at firm capacity and the implementation of auto switching schemes to transfer load to healthy busbars. The ability to transfer load between substations at the distribution level also aids in this ability to meet the Technical Rules requirement.

2.3. Comparison with Other TNSPs

In order to compare the current reliability standards for the Perth CBD Boundary load, an assessment of other cities CBDs network security standards has been undertaken to fully understand how the criteria may differ and how it applies to their existing networks. This section describes the transmission architecture implemented in other Australian CBDs as well as some conclusions drawn from major European cities' reliability standards.

2.3.1. Sydney CBD Transmission Network

Several 330/132 kV substations supply the Sydney CBD and are heavily interconnected via the 132 kV network [9]. Transformers are used to step down the voltage from the transmission system to the distribution system via 132/11 kV transformers. The zone substations typically consist of four 50 MVA transformers and are paired with one other zone substation. The way in which Sydney differs from Perth is that the transformers are not all supplied from the same 132 kV circuits. Two 132 kV circuits supply two transformers at one substation, with two transformers from the paired substation teeing into the circuits, one on each line. A similar arrangement supplies the four other transformers. This allows for continued supply of at least 100 MVA (2 x 50 MVA transformers) should a fault occur on the 132 kV infeeds supplying the other transformers. Figure 1 shows the Sydney CBD transmission arrangement.



- **Figure 1 Sydney CBD Transmission Arrangement [10]**

A disadvantage that can be seen from this arrangement is that a transmission circuit fault, depending on location, would effectively remove one transformer from each site. However, due to the number of transformers at each zone substation, the load is still able to be supplied.

2.3.1.1. Sydney CBD Transmission Reliability Standards

Under the current transmission architecture, the Sydney CBD provides bumpless coverage for N-1 contingencies. A high firm capacity is accomplished due to the number of transformers and the four independent transmission supplies to the zone substation. The existing arrangement also lends itself to a continuity of supply that is not interrupted during a contingency event.

Because of the way in which the network operates 132 kV and 330 kV in parallel, the criterion is referred to as a “modified N-2”. However, in actual practice it is N-1 operated simultaneously across both voltage levels. The 330 kV network relies on the underlying 132 kV system to provide full backup (the system is operated normally closed) for either an N-1 or N-2 contingency. The 132 kV system is planned to N-2, with no loss of load in the Sydney CBD. For a second credible contingency, load must be restored to the Sydney CBD within one hour. This can be seen as more stringent than the existing N-2 criterion for the Perth CBD Boundary.

There is some capability to transfer loads at 11 kV, however there is some interruption to supply as switching operations take some time to apply. The wider Sydney region also allows for load shedding outside of the Sydney CBD in the inner metropolitan area in order to provide continued supply to the Sydney CBD until such time as corrective switching takes place.

The Sydney CBD is not planned for loss of an entire substation. The risk is mitigated by the configuration of the 330 kV and 132 kV busbars, surveillance and security, plant design etc. The 330 kV configuration is either breaker-and-a-half or mesh. The 132 kV bus is in multiple bus sections. In this sense, the Hay and Milligan Street substations provide a higher level of reliability as HILP events are currently catered for via the distribution network.

2.3.2. Brisbane CBD Transmission Network

The Brisbane CBD operates at different voltage levels to both Perth and Sydney. The transmission voltage employed in Brisbane is 275 and 110 kV. The transmission voltage is then stepped down to 33 or 11 kV before being further transformed to feed local load. The transmission network typically provides two 110 kV circuits to the substation, normally consisting of two 120 MVA, 110/33/11 kV transformers at bulk supply points [11]. Smaller zone substations feed local demand via a mix of 60 MVA and smaller capacity 110/11 kV transformers.

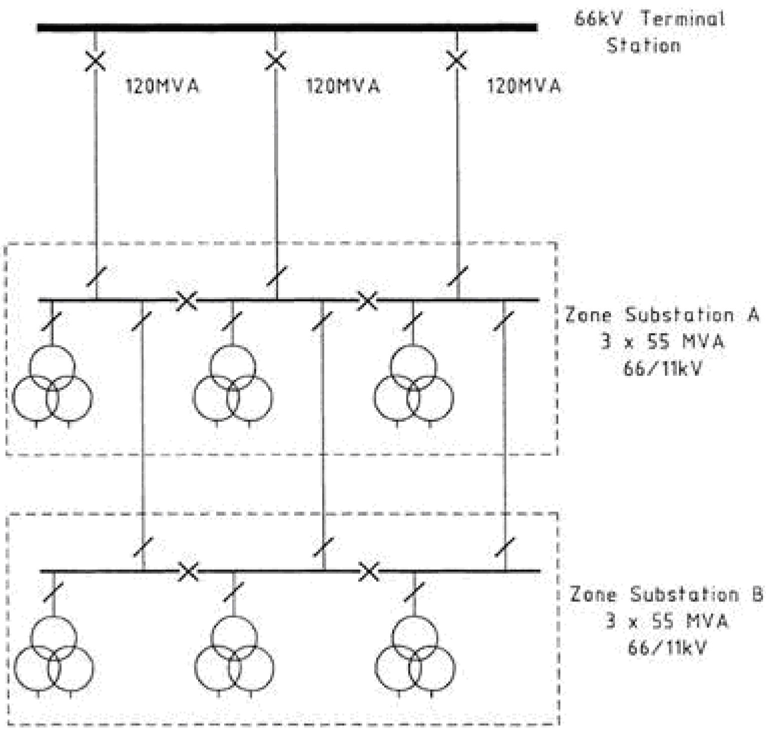
2.3.2.1. Brisbane CBD Transmission Reliability Standards

The contingency criteria for the Brisbane CBD are quite straightforward. Full supply must be maintained for an N-2 contingency event with no interruption on either the 275 kV network or at the bulk supply points. A zone substation is planned only to N-1, again with no interruption time allowed.

It can be seen that the transmission network and bulk supply points in the Brisbane CBD are planned to a higher level of reliability than the Perth CBD Boundary. The bumpless N-1 security afforded to zone substations is superior to the Perth CBD Boundary also; however the Hay and Milligan Street substations provide a higher lever of reliability for N-2, albeit with an allowable two hour interruption to supply.

2.3.3. Melbourne CBD Transmission Network

The transmission network supplying the Melbourne CBD operates at 330, 220 and 66 kV. Typically, a terminal substation will utilise three 66 kV circuits to supply a zone substation. The zone substations typically consist of three 55 MVA, 66/11 kV transformers. At the transmission level, the zone substations are typically interconnected by 66 kV circuits [10]. Figure 2 shows the transmission network employed in the Melbourne CBD.



- **Figure 2 Melbourne CBD Transmission Arrangement**

2.3.3.1. Melbourne CBD Transmission Reliability Standards

Currently, N-1 contingency events within the Melbourne CBD are catered for by the transmission network. As each substation is supplied by three circuits and three transformers, loss of one of the transmission circuits is covered by the remaining two circuits. Similarly for the transformers at the substation, as peak loading does not exceed the rating of two transformers. This provides a true N-1 system as all transformers are typically operated in parallel.

There is no provision for N-2 in the Melbourne CBD. Instead, the security standard requires an N-1 secure to ensure the network is capable of a second outage. Under an N-1 secure system, as detailed in Table 3 of Section 2.1.2, the network is capable of withstanding a single contingency event. After the first contingency, the network is allowed to be reconfigured to support a second contingency. However, this requires a 30 minute window to reconfigure, during which time the network is at risk.

2.3.4. State by State Comparison

In 2009, the Australian Energy Market Operator (AEMO) produced a National Transmission Statement [12] providing a comparison of transmission planning criteria between New South Wales, Queensland, South Australia, Tasmania and Victoria. Table 4 shows this comparison.

The state of Victoria differs from the rest of Australia in that transmission planning is done on a purely probabilistic basis. This type of planning puts more emphasis on a positive net benefit assessment.

Table 4 Comparison of Australian States' Reliability Standards [12]

Criteria	New South Wales TransGrid	Queensland [1] Powerlink	South Australia ElectraNet	Tasmania Transend	Victoria AEMO
Planning objective	Augmentation of the transmission network in anticipation of future demand growth and the efficient transfer of power from existing and new generation to load centres.		Augmentation of the transmission network to service forecast future growth of exit connection point demands.	Augmentation of the transmission network in anticipation of future demand growth and the efficient transfer of power from existing and new generation to load centres.	
Planning obligations	Satisfy system performance requirements as defined in Schedules 5.1a and 5.1 of the Rules. AEMO's system security obligations can be met.				
Additional planning obligations	Contained in a Network Management Plan [17] TransGrid is obliged by legislation to produce for acceptance by the Department of Water and Energy.	Transmission Authority (licence) issued to Powerlink by the Queensland State Government and S.34 of the Queensland Electricity Act 1994 [16].	The Essential Services Commission of South Australia (ESCOSA) determines the reliability standards for South Australia through the South Australia Electricity Transmission Code, which is published on the ESCOSA website [15].	Satisfy minimum network performance requirements defined in Section 5 of the Tasmanian Electricity Supply Industry Regulations 2007 [14].	Satisfy fault level and reactive power generation requirements as referred to in Part A, Chapter 9, of the Rules. Value of unserved energy based on published Value of Customer Reliability [13] .
Transmission Reliability Standard	N-1 across the jurisdiction, with the exception of modified N-2 in the Sydney CBD.	N-1. No variation across the jurisdiction. In addition, as far as technically and economically practicable, the transmission network is to be augmented or extended to provide enough capability to provide network services to persons authorised to connect to or take electricity from the network.	There are six categories of reliability standard in South Australia with a defined category applying to each exit connection point or groups of exit connection points. The standard categories range from N-0 to N-2, depending on the load and importance of load at risk at each exit connection point.	Standards specify the permitted level of load interruption resulting from credible and non-credible contingencies with and without maintenance outages.	Develop the transmission network based on a cost-benefit analysis of energy at risk to satisfy power system security obligations considering the probability-weighted impacts on supply reliability of unlikely, high-cost events such as: - single and multiple outages of transmission elements; and - unexpectedly high levels of demand.
Application of Reliability Standard	System will be able to be secured by re-dispatching generation (AEMO action) so as to withstand the impact of a second contingency without the need for pre-emptive load shedding.	Forecast maximum demand must be met following credible contingencies accounting for AEMO's obligation to achieve a new secure operating state.	Forecast peak demand must be met following credible contingencies (subject to exit point categorisation) with no pre-contingent load shedding by AEMO in its efforts to achieve a secure operating state.	1. For an intact system (no maintenance outages): - maximum load interrupted for any credible contingency event is 25 MW - unserved energy (USE) must not exceed 300 MWh; - maximum load interrupted for a non-credible single contingency is 850 MW or less if necessary to avoid blacking out the system - USE must not exceed 3,000 MWh. 2. For a network element out of service for maintenance: - no more than 18,000 MWh USE following a credible contingency	To maintain power system security, generation rescheduling and load reduction following a contingency is possible. A value of customer reliability is applied to the energy at risk, and network augmentation is justified if this value exceeds the augmentation cost.

SINCLAIR KNIGHT MERZ

Criteria	New South Wales TransGrid	Queensland Powerlink	South Australia ElectraNet	Tasmania Transend	Victoria AEMO
Demand forecast	Demand at or exceeding a one in two year probability of occurrence (50% POE [2]). Demand at or exceeding a one in ten year probability of occurrence (10% POE).	10% POE medium economic growth demand forecast used for planning the main transmission system and 275/132 kV and 275/110 kV transformer capability. 50% POE medium economic growth demand forecast used to identify the limitations within zones. The maximum demand might apply to a particular connection point, across all connection points in a zone or across multiple zones. High and low economic growths are used for sensitivity analysis.	10% POE medium economic growth demand forecast for each exit connection point or group of exit connection points used for planning the meshed 275 kV and 132 kV transmission networks.	10% POE medium economic growth demand forecast. Load reduction is a credible option for managing contingencies as per the minimum network performance requirements defined in Section 5 of the Tasmanian Electricity Supply Industry Regulations 2007.	10%, 50% and 90% POE medium, high and low economic growth demand forecasts. The expected unserved energy is calculated by weighting the results for the three demand scenarios equally.
Available generation	Under 50% POE conditions, able to withstand a contingency under all reasonably probable patterns of generation dispatch or interconnector power flow. Provision made for a prior outage (following failure) of a single item of reactive plant. Under 10% POE conditions, able to withstand a single contingency under a limited set of patterns of generation dispatch or interconnector power flow.	The largest generating unit or unit with greatest impact is assumed to be out of service coincident with the credible contingency being considered. Energy limited plants are assumed to be at a reduced capacity pre-contingent and immediately post-contingent. However, full capacity is assumed when assessing whether or not the system can be returned to a secure state following an initial single contingency.	There are no reliability performance requirements for generation entry connection points. Any generation plant must be able to be out of service without impacting exit connection points.	Expected generation profile developed through analysis of historical behaviour and the potential impact of future generation. Generation can be re-dispatched if that generation is available for service.	Market simulations are conducted with generation maintenance and forced outage rates represented. Simulations reflect committed generation developments and modelled projects.
Generator reactive power capability	Traditionally assumed that all on-line generators can provide reactive power support within their rated capability but in the future intends to align with other utilities in relying only on the reactive capability given by the registered performance standards. Reactive support beyond the performance standards may need to be procured under network support arrangements.	All generators assumed to conform to the higher of the reactive power capability in their registered performance standards or in contracts for additional reactive power capability.	All generators assumed to conform to the range of the reactive power capability in their registered performance standards or in contracts for additional reactive power capability. Non-generator static and dynamic reactive plant devices are considered as elements embraced within the reliability standards. Some load categories may require procurement of reactive support services.	All generators assumed to conform to the higher of the reactive power capability in their registered performance standards or in contracts for additional reactive power capability.	All generators assumed to conform to the higher of the reactive power capability in their registered performance standards or in contracts for additional reactive power capability.

1. In accordance with the Queensland State Government issued Transmission Authority – No. T01/98, Powerlink Queensland is required to "Plan and develop its transmission grid in accordance with good electricity practice". [18]
2. Probability of exceedance.

2.3.5. International Practice

Moving further afield from Australia, a view was formulated on reliability criteria in major European cities. Throughout continental Europe, the transmission network operates at voltages of 380 or 400 kV. The transmission voltages are then stepped down to a number of different voltage levels, depending on the city. The CBD transmission voltages range from 110 to 220 kV before being further stepped down to the distribution voltage level.

The European CBDs generally use deterministic planning to plan to at least N-1 at the transmission level. In a few instances N-2 or N-1-1 is also considered for planning purposes. However, it cannot be confirmed if these criteria allow for load restoration times or if there must be continuity of supply.

An independent review of transmission planning standards around the world was undertaken by CIGRE. This review provided a high level assessment of transmission networks in a number of countries. As a result of the review, the following comparisons were made:

CONDITION CONSIDERED	USAGE IN COUNTRIES SURVEYED
Short time loadings in planning studies	
- overhead line	10 countries
- cable	5 countries
- transformer	16 countries
Number of circuits removed for planning studies	
N-1 only	12 countries
N-2 (and N-1)	13 countries
Loss of busbar	12 countries
Loss of generation unit	20 countries
Probabilistic	9 countries 4 further countries are developing probabilistic techniques, or already have them available
Deterministic	24 countries
Special transfer requirements for zones or groups of circuits	10 countries
Voltage limits	Most countries allow post-fault voltage to vary +5/-10% of nominal in planning studies
Generator stability	21 countries plan their transmission systems to be stable after a three-phase fault; 11 out of these 21 carry out additional tests of two-phase and single-phase studies
FACTORS INFLUENCING THE CHOICE OF REINFORCEMENT	**USAGE IN COUNTRIES**
i) System losses	19 countries
ii) Generation production costs	11 countries
iii) Transmission operation and maintenance	7 countries
iv) Cost of unserved energy	11 countries

Summary of Cigré Review of Transmission Planning Standards

- **Figure 3 CIGRE Review of Transmission Planning Criteria**

As indicated in Figure 3, of the 24 different standards reviewed half require planning to only an N-1 reliability standard and the other half plan to a higher N-2 level of reliability. The planning standards also include deterministic planning methods in almost every standard sampled, with approximately half already implementing or developing probabilistic methods. It should be noted, it is not known if these standards dictate bumpless N-1 or N-2 reliability or if there is an allowable restoration of supply time.

2.3.6. Western Power Transmission N-1 Criterion

Currently, the Technical Rules allow interruption of supply to a customer for an N-1 contingency event for a period of up to 30 seconds within the Perth CBD Boundary. This is not as rigorous as other standard planning practices, as demonstrated in the preceding sections. An extensive review of existing documentation does not clearly state from where this allowable switching time originated. It is assumed that the criterion has been in place since the construction of Milligan and Hay Street Substations in the 1970s, utilising a 30 second switching time to ensure safe switching operations of the original electromechanical devices. These devices have since been replaced with digital devices, capable of operating in much shorter switching times.

Another possible explanation for the allowable switching time is referenced in the 1988 Transmission Planning Criteria. The criteria stated that new substations should be planned and designed to operate with all transformers in parallel. It is recognised that due to fault level rating limitations on the distribution system, however, that most existing substations are operated with either a split MV busbar or with transformers on standby [13]. This would indicate the existing transformers are not designed to run in parallel as this creates high fault levels and the MV busbars can only be operated interconnected (solid) post fault once the switching scheme operates to redistribute load.

It is therefore assumed that the existing N-1 criterion for the Perth CBD Boundary has remained unchanged, regardless of the capability of the network to restore supply in a shorter duration as a result of no public concern due to loss of supply.

By comparison to other CBDs described in Section 2.3, the existing criterion in the Technical Rules is lenient in that it allows for switching time to restore supply. Recognising the importance of load within the Perth CBD Boundary, the Western Power Network should move toward a bumpless or reduced interruption time N-1 system within the boundary which is more in line with other standard planning practices in Australia and around the world.

It is recognised, however, that such a move would potentially require significant investment within the Perth CBD Boundary. A move to a bumpless system would require the MV busbars to be operated interconnected (solid) under normal network conditions. The present fault level rating limitations would require attention through methods such as installation of higher impedance transformers, series reactors, fault current limiters, higher rated switchgear, etc. As the appropriate equipment would be required to be incorporated into the existing substation design, the feasibility of implementation must be considered as well. Whilst some zone substations may already have a design that could accommodate some of the components such as series reactors or fault current limiters, this may not be possible at other sites where space is limited. Additionally, if installation of higher impedance transformers is seen as the preferred investment strategy, the existing transformers would require to be replaced, some with significant service life still remaining.

Alternatively, if it is found that the various techniques that may reduce fault levels are not suitable for the Western Power Network further consideration can be given to the existing switching schemes. As technology has advanced, automatic switching schemes have become much more common and many are capable of operating very quickly. It is the opinion of SKM that increasing the speed at which the existing devices switch through use of more recent technology will reduce the interruption time seen by customers. The present interruption time of 30 seconds could be reduced significantly and, given the present capabilities of most modern equipment to ride through temporary power interruptions, an interruption time in the order of 5 seconds may not even be noticed by consumers.

Additionally, the transmission network reliability could be improved through further development of the distribution network. Adopting self healing distribution automatic switching techniques, by which the distribution network is able to identify, locate, diagnose and isolate the problem to heal itself, may serve to improve interruption time as switching would not be required at the transmission level. Self healing networks are discussed more in Section 5.3.

Determining the economic impact to customers of reducing the outage time in an N-1 event from 30 seconds towards bumpless would require detailed analysis of customer financial impacts that are beyond the scope of this review. However, SKM does not believe there is enough economic benefit to justify a holistic change to the network to move to a bumpless N-1 system if this is the only benefit that is captured.

Given the technologies now available and the fact that many of the assets in the CBD Load Area are approaching the end of their serviceable life, opportunity exists to significantly reduce customer outage times or even achieve a bumpless (no outage) solution. Where this can be achieved with limited additional cost, it is recommended Western Power pursue this outcome.

2.3.7. Western Power Transmission N-2 Criterion

By contrast to the existing N-1 criterion, the N-2 criterion used in the Perth CBD Boundary is comparable to the other Australian CBDs:

- The Sydney CBD operates a modified N-2, but allows some load shedding outside of the Sydney CBD in order to ensure supply is maintained; in such an event, the load must be restored to the Sydney CBD within one hour.
- Brisbane caters for N-2 events on the transmission network and bulk supply points within the Brisbane CBD, requiring the full load to be supported at peak demand with no loss of supply.
- The Melbourne CBD only provides N-2 coverage for the 220/66 kV terminal stations located outside of the Melbourne CBD. It should be noted an N-1 secure standard applies to the Melbourne CBD which, while allowing for the network to support a second contingency, has a 30 minute reconfiguration window during which time the network is at risk.

Following the comparison of the Perth CBD Boundary contingency criteria against other standards adopted on the Australian East Coast, it is thought that the existing Perth CBD Boundary criteria is comparable to other utility practice and reflects a reasonable planning standard. It is therefore recommended to maintain the existing N-2 transmission criterion within the Perth CBD Boundary.

Expansion of the Perth CBD Boundary

Whilst the security standard for the Perth CBD Boundary was found to be sufficient and should not be altered, it is also necessary to consider the physical boundary and whether or not it should be extended beyond the existing definition. In order to accurately assess this, an examination of the existing and proposed new loads to be supplied within the Perth CBD Boundary must be conducted.

The existing loads within the Perth CBD Boundary are a mix of commercial and residential, with some industrial consumers. Additionally, load of major importance, such as the Australian Stock Exchange, is within the boundary as well as the major centre of commerce for the wider Perth area. The original N-2 contingency criterion was developed in recognition of the economic importance of loads located in this small area to the conduct of business throughout the state [5]. Loss of supply to these loads would cause considerable damage to the reputation of Western Power.

A number of recent load developments have been identified which may serve to extend the Perth CBD Boundary. Notable developments[7] are the Perth City Link, Perth Waterfront and the East Perth Riverside development which will see the WACA, Gloucester Park and Trinity College integrated with the new development[8]. The Perth Waterfront load, due to its location, will be afforded an N-2 level of security. Perth City Link is located immediately to the North of the existing Perth CBD Boundary and, under the present definition, will not be afforded N-2 security. As the type of load being supplied is a mix of transit, commercial, retail, public space and residential with no load of major importance such as a hospital, data centre or stock exchange as seen within the Perth CBD Boundary, it is not recommended to expand the boundary to incorporate this development.

The Riverside load is located further from the present Perth CBD Boundary substations. It may therefore be prudent to establish a wider boundary, or create an islanded N-2 network, as customers in this area may require a higher level of security than presently offered. However, with the present load demand in the Eastern part of the Perth CBD, including load supplied by Forrest Avenue and Wellington Street, amounting to some 60 MVA, it is recommended not to expand the boundary beyond that defined in the Technical Rules in the short term. As the load continues to grow through this study horizon, it is anticipated that demand in that area will increase to some 135 MVA. Including the Riverside development this could amount to more than 165 MVA of load by 2036.

Furthermore, expansion of the boundary would drive considerable additional investment as significant work would be required at both transmission and distribution level to ensure N-2

[7] Further information on the load developments identified can be found on the Metropolitan Redevelopment Authority's website: http://www.mra.wa.gov.au/

[8] No formal application has been made for supply to the Riverside development. It is anticipated, however, that an application will be made for supply in excess of 30 MVA.

reliability. This may be in the form of new transmission infeeds or additional distribution interconnections to provide full back up during a contingency event. As there have been no significant complaints concerning the existing security of supply both within the Perth CBD Boundary and without, it would appear that further investment to expand the existing Perth CBD Boundary is unjustifiable. That said, all new major loads should be analysed on a case by case basis to determine the broader economic, societal and environmental impact, should the appropriate level of security not be afforded and a major incident occur.

Therefore, it is recommended that Western Power continue to monitor the load density as new establishments are developed and review the boundary periodically or as new major developments arise that may require N-2 security. In the interim any new Perth CBD Boundary substation developments outside this boundary should be planned initially for N-1 with a view to potentially providing for N-2 dependant on load growth and characteristics.

2.3.8. Deterministic Versus Probabilistic Reliability Criteria

At a high level, two approaches are adopted to planning criteria. These approaches are:

1) A deterministic approach that defines the level of redundancy in network capacity that is required to meet peak load.
2) A probabilistic method that applies failure rates to all network assets and uses probabilistic techniques to determine the likelihood of customer impact for various network configurations and load demands considered. This approach typically takes the forecast impact on customers and combines this with a value of customer reliability. The resulting "social cost impact" is then included in business case comparisons to demonstrate the "full" economic impact of the various infrastructure solutions proposed.

At present, only deterministic planning is used within Australian states with the exception of Victoria. Deterministic standards are the output of a large probabilistic planning study to determine the overall efficiency of the rules and reduce the need to undertake probabilistic planning for every investment. However, probabilistic planning is often used to justify investment which may not otherwise be justifiable under deterministic planning. For example, where minor investment in the network may enhance security of supply, probabilistic planning may be used to strengthen the argument for such an investment where normal planning practices may not demonstrate a strong enough need. HILP events are other such instances where probabilistic planning may be used to provide a justification for network investment. On the other hand probabilistic planning may not always demonstrate the net benefit associated with an N-1 augmentation, which would otherwise be developed under deterministic planning criteria. This presents limitations to the probabilistic approach that the reputational impacts of the outage are difficult to quantify and value.

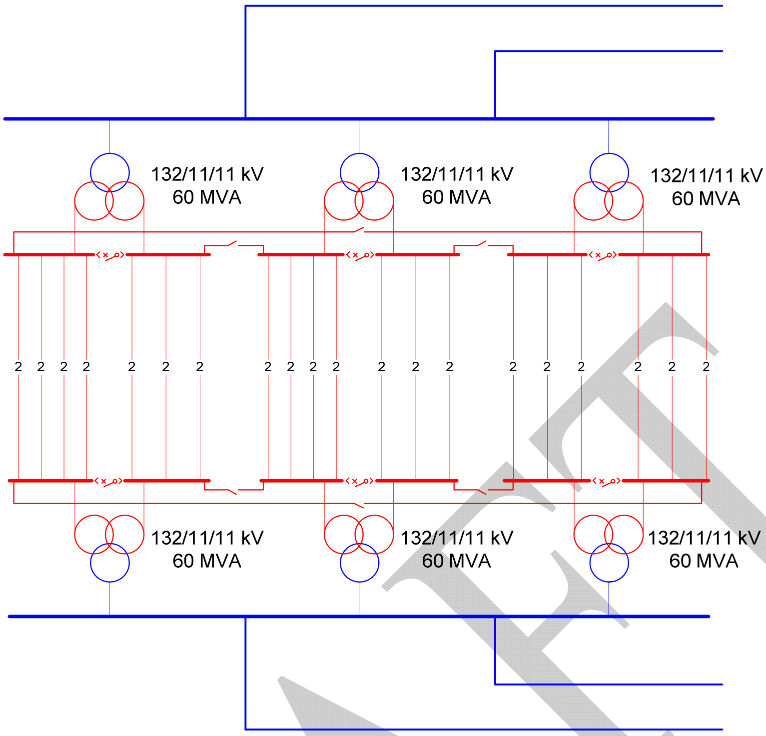
In some ways, the probabilistic approach to network planning is favourable as it can directly demonstrate to a regulator the full economic impact of spending associated with redundancy in the network. However, to be adopted systematically (for all investments) it requires a much higher level of complicated analysis and the determination of the value of customer reliability or VoLL, not presently used by Western Power, becomes critical to investment decisions. Given there are some limitations with the approach and a value of customer reliability can be difficult to estimate, a mixture of both deterministic and probabilistic approaches is most attractive.

Where enhanced security is required, probabilistic planning may help justify the investment. However, any move to a probabilistic planning criterion would need to be proposed by Western Power in the Technical Rules and accepted by the ERA. SKM note that adopting a probabilistic approach would result in a material cost burden on Western Power and the ERA as new systems and capabilities must be developed and/or funded. Thus, SKM is of the position that such a fundamental change in planning criteria would not be prudent in the short term. It is recommended that Western Power pursue probabilistic techniques in the long term to more accurately establish the risk associated with the staging of various programs of work that have been identified using deterministic approaches. Furthermore, probabilistic techniques could be included in specific projects, where suitable, to drive an investment. In such instances, approval from the ERA should be obtained before this type of analysis is implemented as part of the planning process.

2.4. Comparison with Other DNSPs

In order to compare the current reliability standards for the Perth CBD Boundary from a distribution perspective, an assessment of other CBDs needs to undertaken to fully understand how the criteria may differ and how it applies to their existing networks. This section describes the distribution architecture implemented in other Australian CBDs as well as some conclusions drawn from major European cities' reliability standards.

However, before exploring the architectures employed elsewhere, it is important to understand how the distribution network within the Perth CBD Boundary is configured. Figure 4 indicates the existing arrangement for Hay and Milligan Street Substations which supply the majority of load within the Perth CBD Boundary.

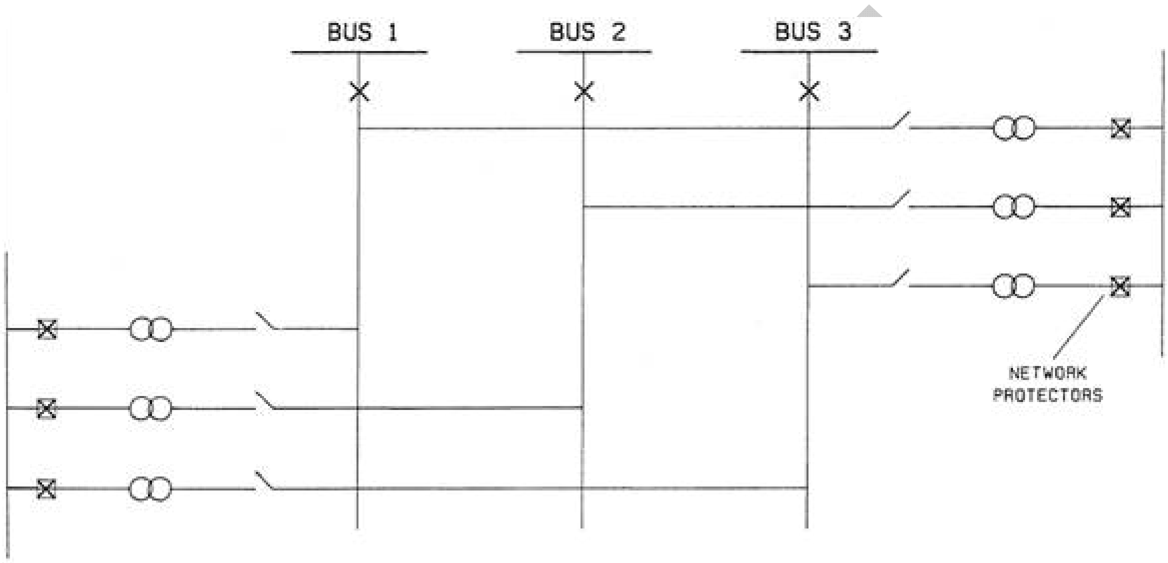


- **Figure 4 Perth CBD Distribution Network Architecture**

The figure above is a simplified representation of the Perth CBD Boundary distribution network. Hay and Milligan Street Zone Substations are heavily interconnected at the distribution level through feeder pairs. A feeder pair is one 11 kV cable run between the sites with a normally open point in the middle, effectively creating two 11 kV cables. Each side of the feeder is then loaded to no more than 50% of its rating. In this manner, N-1 support can be provided on the distribution network with some switching time as a fault on a feeder can be picked up by the paired feeder.

2.4.1. Sydney CBD Distribution Network

The Sydney CBD encompasses an area of approximately 2 km^2 with an average load density of 300 MVA/km^2. Sydney currently implements what is known as the Triplex system at an operating voltage of 11 kV. The Triplex system consists of three 11 kV buses with a single feeder each. At each distribution substation there are three transformers, each taking supply from one of the 11 kV feeders. The three transformers are joined to a common LV busbar. The Sydney Triplex system is shown in Figure 5.



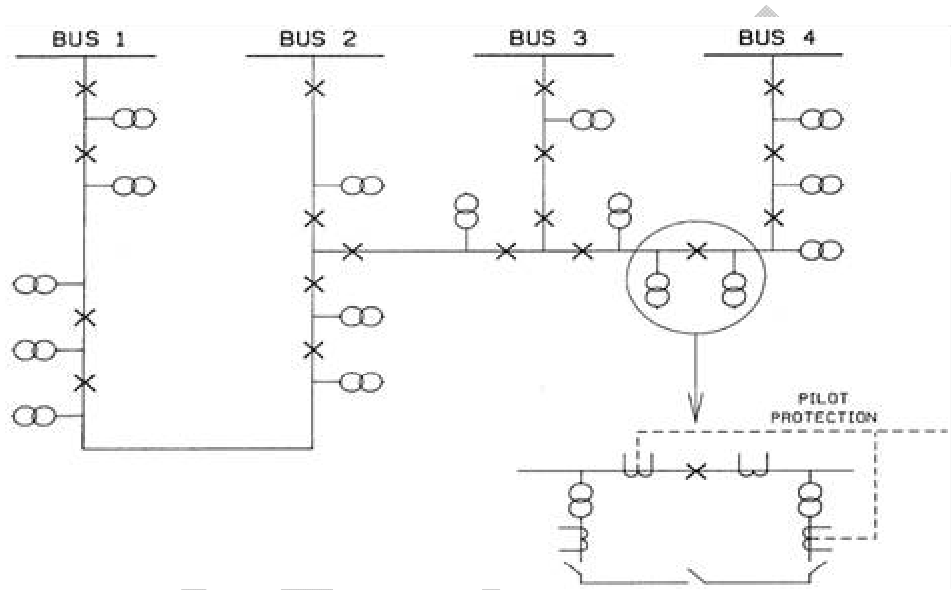
- **Figure 5 Sydney CBD Triplex System [10]**

This system inherently provides better reliability to customers than the Western Power architecture as the supplies come from three unrelated sources rather than two. This approach also allows for failures of RMUs and distribution transformers while still supplying the customer. By comparison to the Perth CBD Boundary, a failure of an RMU or distribution transformer would result in loss of supply unless LV backup is provided. However this is not a requirement of the distribution network. Should a contingency event occur on one of the 11 kV feeders, only one transformer would lose supply while the other two would remain in service. It is assumed that the transformers are appropriately sized to support the full load on the remaining two should one transformer be lost.

Using this arrangement, the Sydney CBD distribution network is capable of providing bumpless service should an N-1 contingency event occur. This is more secure than the existing Perth CBD Boundary distribution system, which allows for a brief switching period for load to be restored on the distribution network for a contingency event.

2.4.2. Brisbane CBD Distribution Network

The Brisbane CBD is approximately 2.25 km^2 in total area with an average load density of 180 MVA/km^2. In Brisbane, the network is highly interconnected at 11 kV and uses various open points to control supply from one of the busbars. This ensures that supply remains continuous during a contingency event. The distribution transformers are all directly connected to the 11 kV supply before being stepped down to an LV busbar shared with another distribution transformer. The Brisbane distribution system is shown in Figure 6.



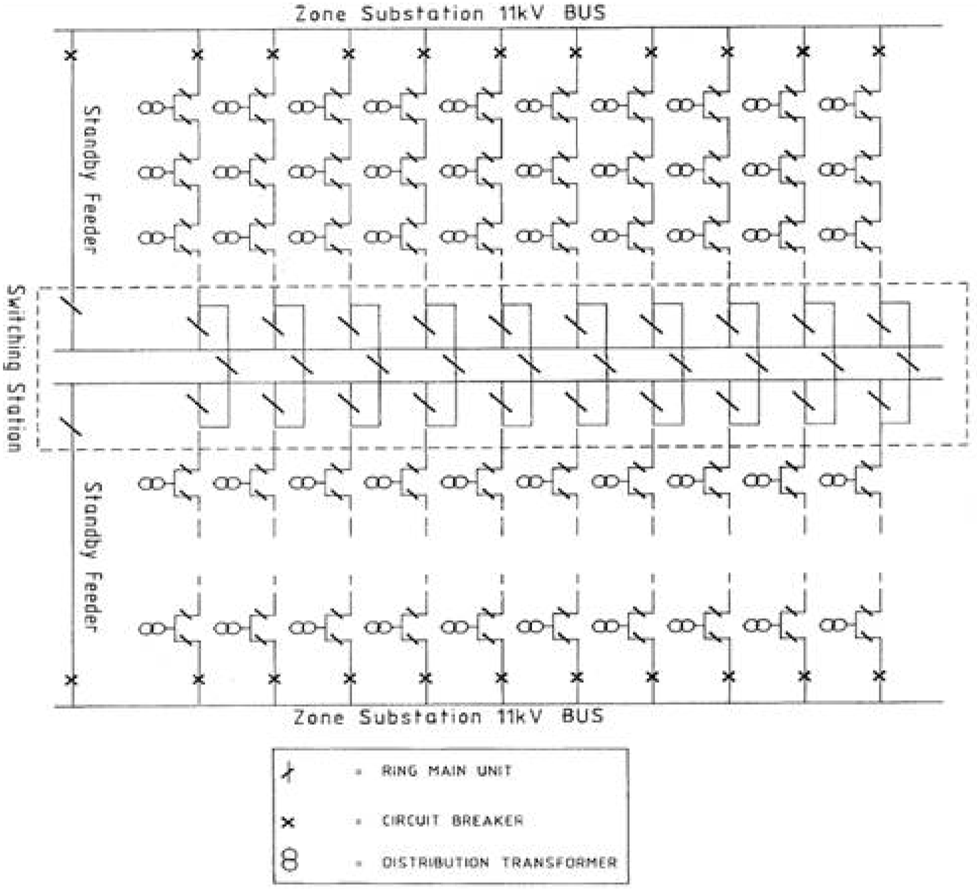
- **Figure 6 Brisbane CBD Distribution System [10]**

The distribution reliability criterion for the Brisbane CBD stipulates that N-1 reliability must be afforded with no interruption to customer supply. This is accomplished by two distribution transformers sharing an LV busbar, as shown in the bottom right corner of Figure 6. The open points in the network can be changed to isolate the fault location and supply assumed by the other distribution transformer sharing the LV busbar. Similar to Sydney, this system provides better security and reliability than the distribution network within the Perth CBD Boundary.

This distribution network architecture helps support the transmission network as considerable load can be transferred in the event of a fault. Also, due to the more interconnected nature of the distribution network in Brisbane, feeder utilisation can be much higher..

2.4.3. Melbourne CBD Distribution Network

The Melbourne CBD distribution network supplies an area of approximately 5 km^2 with an average load density of 160 MVA/km^2. It is supplied by 11 kV radial feeders meeting at open points. Groups of up to 10 loaded feeders are backed up by a single unloaded feeder. A typical customer substation has one ring main unit per transformer and the load is supplied by a minimum of two transformers [10]. Figure 7 indicates the distribution network in the Melbourne CBD.



- **Figure 7 Melbourne CBD Distribution System [10]**

In contrast to both Sydney and Brisbane, the Melbourne distribution system is not capable of providing bumpless N-1 support. Should a fault occur on one of the distribution feeders, the unloaded feeder can support the load, however a certain amount of switching time would be required. There is no mandated restoration time. This is less stringent than the existing criteria for the Perth CBD Boundary as the distribution network is planned to N-1 with an allowable brief switching period to restore load, as discussed in Section 2.1.4.2, assumed to be ten minutes as per System Management's Control Room Instruction 51-01 [6].

2.4.4. Greater and Central London Distribution Network

The UK differs from the Australian networks currently assessed by a basic concept. DNSPs in the UK are actually responsible for the sub transmission network and the distribution network (132 kV and below). It is important to differentiate this as the requirements for the DNSP encompass much more than their equivalent in Australia.

The DNSPs must adhere to Engineering Recommendation P2/6 [14]. This recommendation dictates the minimum load demand that must be supplied after a first and second circuit outage. Various classes of supply are identified along with a range of group demand for the class. Table 5 provides the planning criteria for DNSPs in the UK. Of particular relevance to the Western Power distribution network are classes of supply A-D, which are most similar to the Perth CBD Boundary zone substations. Hay Street and Milligan Street would be considered class D group demand (60 MW $\leq$ zone substation demand $\leq$ 300 MW).

- **Table 5 Engineering Recommendation P2/6 [14]**

Class of supply	Range of Group Demand	Minimum demand to be met after First Circuit Outage	Minimum demand to be met after Second Circuit Outage	Notes
A	Up to 1MW	In repair time: Group Demand	Nil	Where demand is supplied by a single 1000kVA transformer the "Range of Group Demand" may be extended to cover the overload capacity of that transformer.
B	Over 1MW and up to 12MW	(a) Within 3 hours: Group Demand minus 1MW (b) In repair time: Group Demand	Nil	
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of (Group Demand minus 12MW); and 2/3 of Group Demand (b) Within 3 hours: Group Demand	Nil	Group Demand will be normally supplied by at least two normally closed Circuits or by one Circuit with supervisory or automatic switching of alternative Circuits.
D	Over 60MW and up to 300MW	(a) Immediately: Group Demand minus up to 20MW (automatically disconnected) (b) Within 3 hours: Group Demand	(c) Within 3 hours; For Group Demands greater than 100MW: Smaller of (Group Demand minus 100MW); and 1/3 Group Demand (d) Within time to restore arranged outage: Group Demand	A loss of supply not exceeding 60 sec is considered as an immediate restoration. The Recommendation is based on the assumption that the time for restoration of Group Demand after a Second Circuit Outage will be minimised by the scheduling and control of planned outages, and that consideration will be given to the use of rota load shedding to reduce the effect of prolonged outages on consumers.
E	Over 300MW and up to 1500MW	(a) Immediately: Group Demand	(b) Immediately: All consumers at 2/3 Group Demand (c) Within time to restore arranged outage: Group Demand	The provisions of Class E apply to infeeds to the distribution system but not to systems regarded as part of the interconnected Supergrid to which the provision of Class F apply. For the system covered by Class E consideration can be given to the feasibility of providing for up to 60 MW to be lost for up to 60 seconds on First Circuit Outage if this leads to significant economies. This provision is not intended to restrict the period during which maintenance can be scheduled. The provision for a Second Circuit Outage assumes that normal maintenance can be undertaken when demand is below 67%. Where the period of maintenance may be restricted paragraph 3 of section 2 applies.
F	Over 1500 MW	In accordance with the relevant transmission company licence security standard		

As shown in the table, any demand group of 1 MW or less (Class A) does not have a defined restoration time. However, for demand groups of over 1 MW and up to 12 MW (Class B), supply must be restored within three hours. There is also an allowable loss of load of up to 1 MW. For direct comparison to the Perth CBD Boundary zone substations, an N-1 event at a Class D substation, similar to Hay and Milligan Street, must be able continuously supply total substation demand minus 20 MW and fully restore the total demand within three hours. It should be noted a loss of supply of 60 seconds or less is considered immediate restoration. For an N-2 event, the smaller of total demand minus 100 MW or one third of group demand must be restored within three hours.

In the case of the higher load density parts of Central London, a geographical area of approximately 20 km^2 with a load density of 80 MVA/km^2, increased security has historically been available via LV interconnections. This is reflected in the DNSP's security planning standard as detailed in Table 6. It can be seen from Table 6 that all demand groups in excess of 1 MW are secured within 60 seconds essentially by LV switching.

- **Table 6 Enhanced Security Requirements for Central London**

P2/6 – Enhanced demand security for Central London (non-licence)			
Class of Supply	**Group Demand**	**First Circuit Outage**	**Second Circuit Outage**
A	up to 1 MW	In repair time: Group Demand	No requirement
B	over 1 MW to 12 MW	a) Within 60 seconds: Group Demand	No requirement
C D	over 12 MW to 60 MW and over 60 MW to 300 MW	a) Within 60 seconds: Group Demand	b) Within 3 hours: Demand of all consumers at ½ Group Demand c) Within time to restore arranged outage: Group Demand
E	over 300 MW to 1500 MW	a) Immediately: Group Demand	b) Immediately: Demand of all consumers at 2/3 Group Demand c) Within time to restore arranged outage: Group Demand

From Table 6, the security requirements that would be most comparable to the Perth CBD Boundary distribution network would be for demand classes A-D (Hay Street and Milligan Street would be considered Class D). Comparing these criteria to the Perth CBD Boundary, it can be seen that a first circuit outage in Central London has a stricter requirement than the Perth CBD Boundary in that total group demand must be restored within 60 seconds for an N-1 contingency. Similarly, an N-2 requirement must also be met in that half of the total load at the substation must be restored within three hours. At a distribution level, this is superior to the Perth CBD Boundary which does not afford N-2 security.

2.4.5. Berlin

The Berlin CBD is quite different to all of the other CBDs discussed previously as it incorporates an area of 194 km^2. The load density is 25 MVA/km^2 and is relatively evenly distributed. Berlin operates a transmission network with a voltage of 380 and 220 kV. The sub transmission network operates at 110 kV.

The distribution network mainly consists of 10 kV open rings and sometimes closed rings if the customers have higher reliability requirements. There is an N-1 requirement, however it is not bumpless as there is some switching time required to restore load. This is similar to the Perth and Melbourne CBD level of reliability.

2.4.6. Distribution N-1 Criterion

A direct comparison of the other Australian CBD distribution networks and some European distribution networks indicates that some of those described above are capable of withstanding an N-1 contingency event without restoration time. However, Melbourne, London (for loads greater than 1 MW) and Berlin all require switching periods to restore load. This is comparable to the existing Perth CBD Boundary criterion, which allows for a brief interruption time for remotely controlled switching to restore supply to a faulted feeder [1]. The Sydney and Brisbane CBD distribution arrangements are generally more secure and give a higher standard of reliability [10]. The distribution arrangement of the Melbourne CBD also allows for higher utilisation of feeder circuits than the Perth CBD Boundary as a fault on a feeder is supported by the one spare feeder connected to the central switching station.

It should be noted these arrangements have not developed without significant expenditure over that invested within the Perth CBD Boundary. This is an important consideration when deciding if the Perth CBD Boundary N-1 distribution criterion should be changed. By comparison to other CBDs, however, the distribution network operated within the Perth CBD Boundary appears to be the most inefficient in terms of circuit utilisation. Due to the congestion issues and the cost of installing new cable conduits discussed in the beginning of this section, SKM is of the opinion that continuing the practice of limiting cable utilisation to 50% is not economically appropriate moving forward.

Additionally, several other CBDs have adopted a bumpless N-1 standard at distribution level whereas there is an allowable switching time within the Perth CBD Boundary. This is accomplished through installing two or more distribution transformers to customers. Furthermore, some of those CBDs reviewed allow for parallel operation of the LV busbar, ensuring a bumpless supply. The current distribution network within the Perth CBD Boundary, however, is not configured in this manner as distribution transformers are installed only to supply the load required load and no more. Additional distribution transformers would be required within the Perth CBD Boundary to ensure bumpless supply which would result in significant expenditure that cannot be easily justified, especially as there has been a lack of public concern over the present security of supply.

As cable congestion within the Perth CBD Boundary is a more pressing issue, it is recommended to review the existing distribution planning practice of limiting cable utilisation to only 50% in favour of increased cable utilisation, as seen in the Brisbane or Melbourne CBDs. This could be accomplished through creating a more interconnected network and altering planning standards to be similar to the existing metropolitan area distribution feeder standard, as stated in Section 2.5.5.4 in the Technical Rules. It should be noted that such an interconnected network may not require new feeders to be installed between substations, only short sections of cable to connect existing feeders. In order to provide the necessary N-2 support to the transmission network within the Perth CBD Boundary, however, the existing automatic switching schemes employed at Hay and Milligan Street would be required to be extended to ensure the required 2 hour restoration time can be met.

2.5. Managing HILP Events

The Technical Rules make no reference to planning standards for HILP events. That is to say HILP events are considered outside the minimum standards to be met. However, the existing network arrangement in the Perth CBD Boundary caters for such an event through the distribution network, but only for load supplied by Hay and Milligan Street Zone Substations, or from the surrounding substations interconnected to Hay Street or Milligan Street. This was previously a requirement of the Perth CBD Contingency Criteria [10].

The current distribution architecture within the Perth CBD Boundary allows for full back up of one substation via the DTC cables installed between the sites. This implies that the substations could withstand a HILP event following extensive distribution switching. Whilst this is superior to other CBDs in Australia and around the world, it is not without problems. Feeder exits at existing sites are quickly being used up and in the nearer future congestion issues will continue to get worse as more distribution cables are installed in line with current practice. This may mean that the sites are no longer capable of continuously supplying power to the load within the Perth CBD Boundary during a HILP event without further augmentation. Though it is no longer an explicit requirement of the Technical Rules, Western Power should continue to adopt architecture within the Perth CBD Boundary which, in allowing for N-2 compliance, also facilitates load restoration following loss of a substation, bearing in mind the recommendations made in Section 2.4.6 for improving the distribution network. This is currently afforded without any additional expenditure.

Probabilistic planning, as mentioned in Section 2.3.8, can be used to develop and aid the argument for additional investment at the Perth CBD Boundary substations. Determining the likelihood for such a HILP event to happen can steer decisions to install equipment to mitigate against such an event and thereby speed up rebuild time if necessary, invest in further extension of the existing DTC or other such preventive measures. Probabilistic planning for any new substation design should be considered where additional investment would ensure a more robust network within the Perth CBD Boundary.

The lack of requirement to plan for HILP events is largely similar to other Australian CBDs. It should be noted, however, that planning for HILP events in the Western Power Network should only be pursued in the future where a positive net benefit can be determined.

2.6. Reliability Criteria Conclusions and Recommendations

At this time, the existing transmission N-1 criterion for the Perth CBD Boundary is less onerous than most Planning Criteria investigated in this report. Several CBD networks provide a bumpless N-1 transmission response and SKM believes that future augmentations should be designed to this standard as discussed in Section 2.3. The N-2 criterion for the transmission network, albeit with 2 hours reconfiguration time, appears more than adequate for the Perth CBD Boundary and is comparable to other Australian CBDs and with many international CBDs. Table 7 presents a comparison of the transmission reliability criterion for those CBDs presented within this report.

Table 7 Comparison of Transmission Reliability Criterion

CBD	Max. Load Density [MVA/km^2]	N-1 Criterion	N-2 Criterion
Perth	170	Restoration of supply within 30 seconds of first credible contingency.	Restoration of supply within 2 hours of second credible contingency.
Sydney	300	No interruption to supply permitted for first credible contingency (bumpless N-1).	Restoration of supply within 1 hour of second credible contingency.
Brisbane	180	No interruption to supply permitted for first credible contingency (bumpless N-1).	No interruption to supply permitted for second credible contingency (bumpless N-2).
Melbourne	160	No interruption to supply permitted for first credible contingency (bumpless N-1).	Transition to N-1 secure. Must be able to withstand second credible contingency (bumpless) within 30 minutes of first contingency.
European CBDs	80	Generally planned to N-1 security. Unknown if load restoration time is permitted.	Some planning done to N-2 or N-1-1. Unknown if load restoration time is permitted.

Similar to the findings for the transmission N-1 criterion, the distribution criteria is also less onerous than others considered in the comparisons. Given the level of reliability afforded by the existing system is deemed acceptable, alternative architectures will only be able to be pursued if they are equally or more economic and offer improved reliability. Table 8 summarises the reliability criterion for the different CBD distribution networks investigated in this report.

Table 8 Comparison of Distribution Reliability Criterion

CBD	N-1 Criterion	N-2 Criterion
Perth	Restoration of supply within 10 minutes of first credible contingency.	N/A
Sydney	No interruption to supply permitted for first credible contingency (bumpless N-1).	N/A
Brisbane	No interruption to supply permitted for first credible contingency (bumpless N-1).	N/A
Melbourne	Some restoration time permitted for switching time for first credible contingency.	N/A
London	No interruption to supply for load demand under 1 MW. For load demand greater than 1 MW but less than 300 MW, restoration of supply within 60 seconds of first credible contingency.	Restoration of half of total group demand within 3 hours.
Berlin	Some restoration time permitted for switching time for first credible contingency.	N/A

The existing deterministic criteria should be retained; however, probabilistic methods may be used to justify investment above the deterministic standards on a case by case basis where opportunities present themselves for positive net benefit efficient investment. Other issues such as life-cycle costing (including an assessment of the cost of technical losses in asset purchasing decisions) and expected energy not served (EENS) investment drivers are not insignificant in their effect on which planning criteria is best for Western Power. However, the planning criteria has to be seen in terms of restoration and MW losses during both system events and contingencies as seen in the table contained in Appendix F.

2.6.1. Areas for Further Development

Although recommendations have been made concerning improving the security of supply, especially for N-1 contingency events at Perth CBD Boundary substations, there are a few areas that require further investigation before a recommendation can be fully made. These areas would further strengthen any arguments and lend more credibility to the recommendations.

In order to gauge the effectiveness of the existing criteria, customer feedback from the present Perth CBD Boundary customers could be obtained. This could be accomplished via surveys to existing customers or some other form of community engagement. The feedback received can help formulate a general opinion on the performance of the network to date and whether or not the existing criteria should be amended. Western Power is presently in the process of developing a community engagement action plan that can be used to gather feedback from customers.

SKM is aware that the IMO is proposing to undertake a review of the planning criteria for the energy market that will necessitate a position being developed on the value that customers place on reliability. This review could provide additional data to Western Power in determining the financial impact of reliability based investments.

Further, the WEM has a mechanism by which customers are paid to make their load interruptible. If Western Power could determine the location of these customers this would provide useful data on the value customers place on reliability. Additionally, this could be used to support retaining or expanding the existing Perth CBD Boundary.

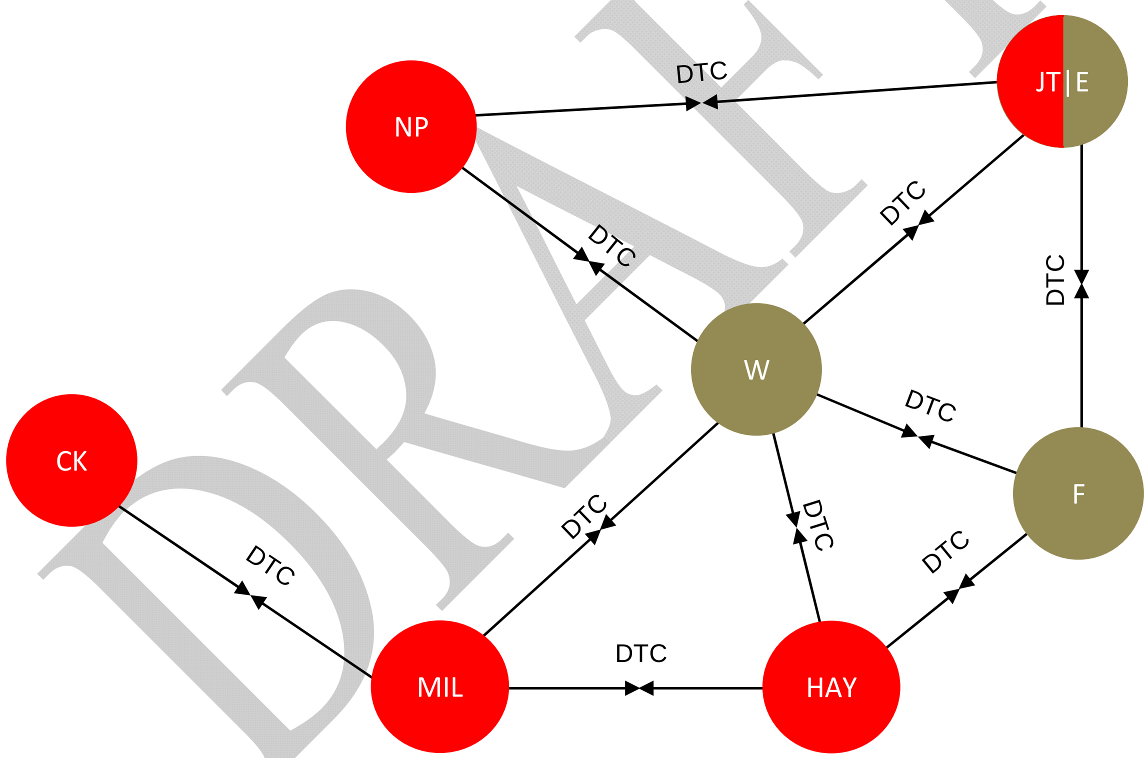
Should it be determined that amending the standards to ensure a higher degree of security to Perth CBD Boundary customers is preferred, the cost impact would need to be assessed. This would require a detailed analysis concerning the amount of additional expenditure required to increase the security of supply, including the associated increase in cost to customers. It may be the increase is unacceptable to the existing customers and an increase in security standards is not a feasible way forward.

3. Distribution Network Architecture

Section 2.4 presented a comparison of the existing Perth CBD Boundary distribution planning criteria against other Australian CBDs and European cities distribution reliability. This section serves to further explore the existing distribution architecture employed in the Perth CBD Boundary with consideration to the conclusions and recommendations detailed previously, such as pursuing distribution architectures that afford a higher level of reliability, in line with international practice.

3.1. The Interconnected Perth CBD Distribution Network

In order to be compliant with the Technical Rules the existing distribution network within the Perth CBD Boundary adopts significant interconnection between zone substations at 11 kV. This is required primarily for N-2 planning standards at a transmission level. The existing distribution network is heavily interconnected with transfer capacity between various sites as shown in Figure 8.



- Figure 8 Existing CBD Distribution Network

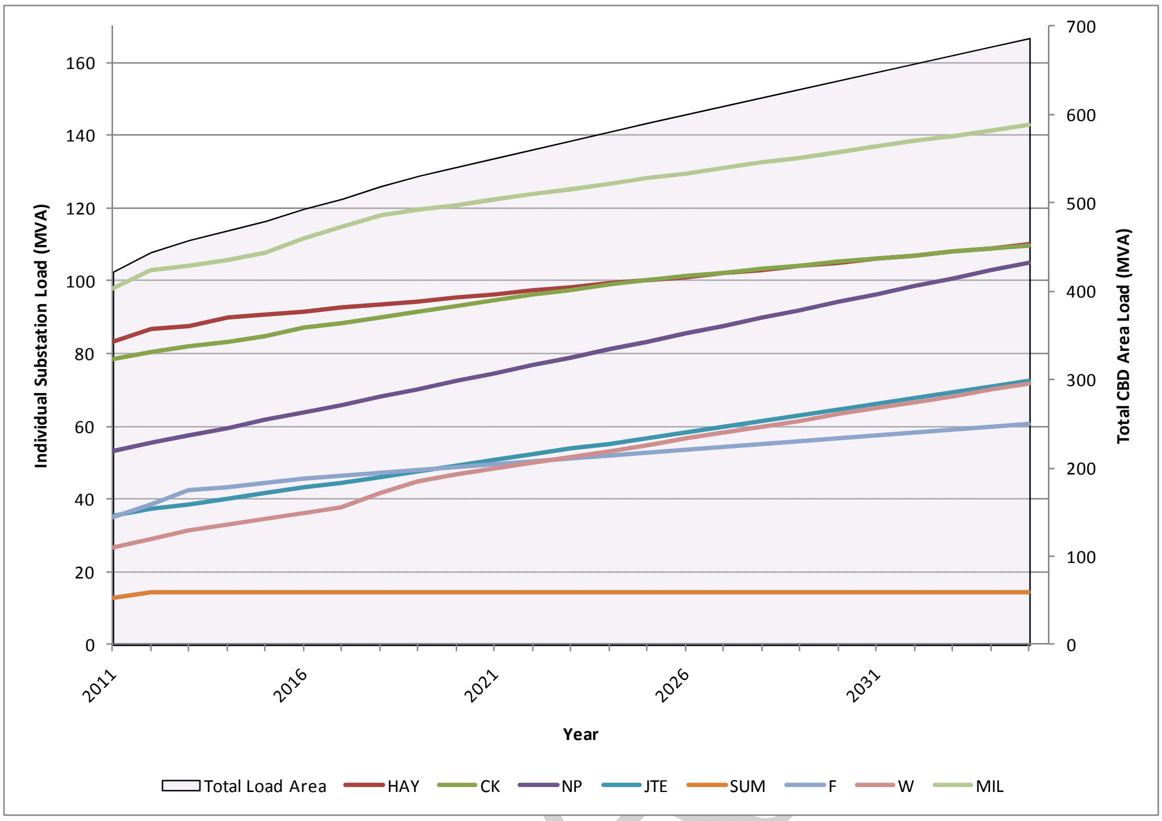
The Perth CBD Boundary distribution network utilises feeder pairs. A pair is made by connecting one feeder from one substation, Milligan Street for example, to one feeder from a second substation, for example Hay Street, with an open point. The two 11 kV circuits are then loaded on average to no more than 50% on either side of the open point. This ensures N-1 support, as per the Perth CBD Boundary distribution planning criteria [7], as the load on a faulted feeder can be supplied by the other circuit in the pair. A disadvantage of this system is the number of cables required to feed the load. Due to a lower utilisation level, more cables are required compared to other DNSPs as the total current carried on each cable is restricted to half the maximum rating, creating high congestion as mentioned in Section 2.4 and investigated further in the SKM report East Perth and CBD Load Area Development Report [3]. This is in contrast to the distribution networks presented in Section 2.4, as multiple feeders are interconnected with various open points which can be moved during a contingency, allowing the cables to be loaded to greater than 50% under normal operation.

There are currently 32 feeder pairs of 11 kV cables installed between Hay and Milligan Street Substations. This enables the sites to be compliant for an N-2 contingency as the load at either substation is deemed to be capable to be transferred to the other within two hours as per the Technical Rules [1], via a DTC scheme discussed in more detail in Section 3.3. Interconnections to other zone substations outside the Perth CBD Boundary allow any N-2 load they supply within the Perth CBD Boundary to be transferred to Hay Street and Milligan Street should an N-2 event occur on those substations.

3.2. Load Growth in the Perth CBD Boundary

The load in the CBD Load Area is expected to increase by approximately 240 MVA in the next 25 years. Many of the sites are already operating close to or exceeding their firm capacity [2] thereby presenting a need for reinforcement. Due to the congested nature of the Perth CBD Boundary and availability of cable routes and corridors, there is a need to review the existing architecture and assess options to increase capacity in the distribution network to meet growing load demand. The assessment will examine the possibility of adopting a higher distribution voltage or building a new substation, among other options. Appendix B shows the forecasted load growth in the CBD Load Area (i.e. no load transfers or sites decommissioned) over the next 25 years.

Figure 9 shows the forecasted load growth at the individual CBD Load Area substations as well as the total load area.



- **Figure 9 2011 - 2036 East Perth and CBD Load Area Demand Forecast (10% PoE)**

3.3. Distribution System Limitations

The distribution network currently operates at 11 kV throughout the CBD Load Area. This is similar to other major Australian CBDs. However, there are severe restrictions on cable exits from substations and available routes within the sidewalks of the Perth CBD Boundary [2]. This is a result of only two large substations supplying the Perth CBD Boundary (i.e. all distribution feeders must come from these two locations). More substations would allow for fewer cables to be installed at each site while still supplying the load. The additional transmission equipment costs would, however, be quite significant. By contrast to the Perth CBD Boundary, the distribution network architectures employed in Melbourne and Brisbane, with similar load densities to the Perth CBD Boundary, promote higher utilisation of distribution cables, thereby reducing the number of individual cables.

Applying this to the Perth CBD Boundary, it may be possible to install short sections of cable between existing feeders to create a more meshed network. It is recognised that such installations may require a more comprehensive control scheme in order to maintain N-2 compliance as more open points would require monitoring and automatic switching schemes to reconfigure the network during double transmission contingency events. Further interconnection may also serve to increase already high fault levels on the distribution network, requiring further investment. The increase in

utilisation may also lead to further cable de-rating, as higher currents would be carried on cables installed in close proximity.

As an alternative to increasing utilisation of the existing cables, a higher voltage in the Perth CBD Boundary could provide significant benefits. The main advantage of a higher voltage is the reduced number of cables required to transport the same amount of power. A reduced number of cables would result in less feeder congestion in roadways and substation exits. Due to improved voltage profiles, a higher voltage cable is also capable of supplying a larger area. For these reasons, various voltage levels of 22 or 33 kV are explored to determine if any benefit can be realised within the Perth CBD Boundary distribution network.

Also, the existing distribution system utilised within the Perth CBD Boundary is configured to provide significant DTC support following an N-2 contingency at Hay and Milligan Street Substations. Potentially this DTC would be required to fully support one of these substations, should an N-2 contingency on the two incoming 132 kV feeders occur. In 2011, the maximum requirement would be following a loss of the JAM-MIL 81&82 circuits resulting in a DTC support requirement of 91.8 MVA (the recorded peak load value at Milligan Street Zone Substation). Examining the load forecast, it can be seen the load at Milligan Street is expected to increase to almost 108 MVA by 2015, implying the distribution network must be able to support load transfers of 108 MVA from Milligan Street to the surrounding substations. For practical reasons, such as cable congestion and limited spare feeder terminations, this may not be possible. There is therefore significant risk involved in continuing to rely on the DTC support to meet the Perth CBD Boundary security criteria.

3.4. Distribution Voltage in the Perth CBD Boundary

3.4.1. Voltage Comparison to Other CBDs

As discussed in Section 2.4, the other CBDs in Australia and worldwide use similar distribution voltage levels to the Perth CBD Boundary.

Table 9 summarises the findings from the previous section.

- **Table 9 Comparison of CBDs**

CBD/City	Area [km^2]	Max. Load Density [MVA/km^2]	Distribution Voltage
Perth	1	170	11
Sydney	2	300	11
Brisbane	2.25	180	11
Melbourne	5	160	11
Central London	20	80	11
Berlin	194	25	10

As can be seen in the table, the Perth CBD Boundary has a similar load density to both Brisbane and Melbourne. However, these CBDs are continuing to operate at 11 kV and no information has been found to determine if a higher operating voltage has been considered for future network development. It is assumed the main reason why these CBDs are able to continually grow while maintaining the same distribution voltage is due to both the increased utilisation of distribution cables and the use of multiple smaller substations.

Brisbane's heavily interconnected system allows for a better level of reliability than that afforded within the Perth CBD Boundary while also improving utilisation of the distribution feeders. Similarly, Melbourne has a higher feeder utilisation level due to its architecture. Both of these architectures cater for continuing load growth. The Perth CBD Boundary distribution network, due to the way in which it supports N-2 security at the transmission level, limits feeder utilisation to no more than 50% to ensure full back up. Recognising the existing limitations on the Perth CBD Boundary distribution network, and the number of dependencies associated with increasing circuit utilisation as discussed in Section 3.3, a higher operating voltage is seen as the preferred long term option to support ongoing load growth within the Perth CBD Boundary and wider CBD Load Area. This may require further investigation into methods to increase feeder utilisation in the interim until such time as a higher distribution voltage could be adopted.

3.4.2. 22 kV vs. 11 kV

There has been some discussion surrounding a change in operating voltage within the Perth CBD Boundary to 22 kV [15]. The discussion below is to investigate the recommendations in this report regarding uprating the distribution operating voltage to 22 kV within the Perth CBD Boundary and its economic viability.

A standard 22 kV feeder cable is capable of carrying 4-18 MVA, depending on conductor size. Standard Western Power conductor sizes indicate that a maximum of 12 MVA could be carried corresponding to twice as much as an equivalent 11 kV standard cable. This means that half the number of cables would be required in a 22 kV network to transport the same power in an 11 kV network. The 22 kV cables are also capable of covering longer distances due to a lower voltage drop compared to the same load on an 11 kV cable. Along the same lines, a 33 kV cable would be capable of three times the amount of current as compared to an 11 kV cable and could serve to further reduce the number of required cables. Figure 10 shows the range of capability for the different voltage levels.

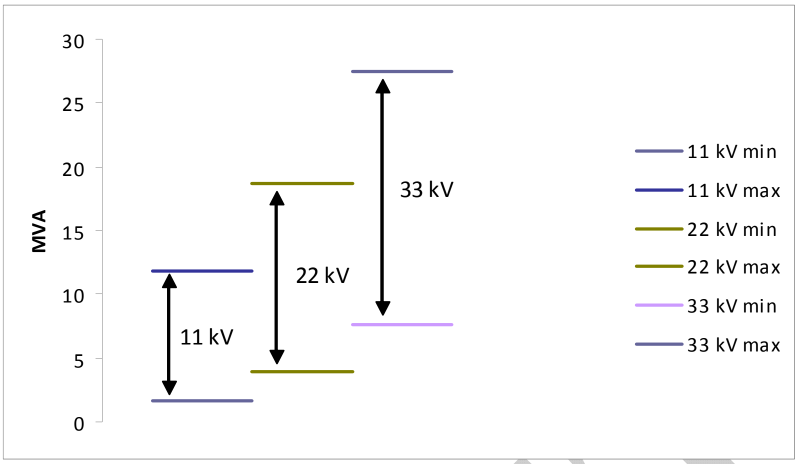


Figure 10 MVA Rating of Distribution Cabling

In light of the figure above, it can be seen that 22 kV cables are more versatile as these cables can operate across a wider spectrum encompassing the upper limit of 11 kV and lower limit of 33 kV cables. It is recognised, however, that a utility would not have a broad range of conductor sizes at the various voltage levels and the overlap in current carrying capability would not be as pronounced. Standard practice would indicate similar conductor sizes would be chosen for each voltage level based on acceptable corporate risk. Therefore, it becomes prudent to question whether a larger conductor size at 11 kV would be more suitable or if an alternative operating voltage should be selected.

At present, the Perth CBD Boundary distribution network utilises 240 mm^2 aluminium conductor cables. As stated, these cables are capable of carrying up to 5 MVA. Should a larger conductor size be used, for example 400 mm^2 or 630 mm^2, potentially up to 12 MVA could be transported on a single cable. Applying this larger conductor size to the Perth CBD Boundary, it can be seen that fewer cables would be required to carry the same amount of load. This could go some way toward reducing the existing feeder congestion issues.

Further consideration must, however, be given to a larger conductor size. Although more power could be carried in the cable, more practical limitations exist that prevent a move to a larger conductor. A larger conductor will have a larger bending radius. The increased bending radius may not allow the cable to be turned into a substation, requiring new cables routes to be found. The standard 11 kV switchboard used by Western Power is capable of supporting a cable size of up to 630 mm^2 without modification and the distribution ring main units and distribution transformers are capable of terminating cables up to 400 mm^2. Any further increase in the conductor size would require a change to the distribution switchgear standards. Similarly, the structures used to support the cables may not be designed for the extra weight associated with a larger conductor size. This would require further investigation should a cable size of 630 mm^2 or larger be installed within the Perth CBD Boundary. These factors would require significant extra investment as the existing cables reach the end of their service lives and require replacement.

The most compelling evidence as to why a larger conductor size is not possible in the Perth CBD Boundary lies in the existing duct penetration. The existing design is only large enough to accommodate 240 mm^2 cables. Should a larger conductor size be used, the ducts would require to be redesigned in order to accommodate the larger cable. This would also require significant investment. It is recognised, however, that a shift from 11 to 22 kV would require substantial investment in its own right and more investigation into the costs and the associated Net Present Cost (NPC) is required to determine the appropriate strategy.

Another comparison that may be used to determine if migration to a higher voltage is an appropriate choice is to examine the load growth over the next 25 years versus the number of distribution feeders required to supply the load. As stated in Section 3.2, the load demand within the Perth CBD Boundary is expected to increase by approximately 240 MVA. Taking into account the existing capacity of an 11 kV feeder and standard Western Power practice of only loading the cables to 50% to support N-1 contingencies at a distribution level and N-2 contingencies at transmission level, this would equate to 40 pairs of cables, assuming all load demand continues to be supplied by cables installed in feeder pairs. On the other hand, with double the current carrying capability, the number of 22 kV feeders required would be only 20 pairs, again assuming all load demand is supplied by feeder pairs. At an average cost of $[redacted] per kilometre, significant savings can be made by using fewer cables at a higher distribution voltage.

At present, some 57.6 km of cable is installed in the CBD Load Area and is rated for 11 kV operation only. Using the cost per metre above, this equates to approximately $[redacted]M to replace these cables like-for-like. Should 22 kV be chosen as the operating voltage, it can be seen that savings of $[redacted]M could be realised as only half the number of cables would be required. This figure does not take into account the fixed cost savings associated with planning and design as well as project management. Furthermore it does not recognise the impact of installation timing on the present value given 22 kV equipment would be installed in half the frequency of 11 kV.

Application to the Perth CBD Boundary

As the existing Perth CBD Boundary is currently supplied at 11 kV, uprating the distribution system to 22 kV would require significant works including the replacement of many of the transformers that do not currently use a 22 kV secondary, replacement of all distribution transformers and ring main switchgear not currently rated to 22 kV, some of which are not owned by Western Power, and possibly the installation of 22/11 kV transformers for sites where upgrade is not feasible, in particular those sites outside of the Perth CBD Boundary that are already interconnected with Hay Street or Milligan Street.

Also, the current network lends itself to expansion by adding satellite sites, or installing transformers at strategic locations and stitching into the existing network by cutting into the existing DTC between Hay and Milligan Street Substations to form new feeder pairs between the satellite substations and Hay Street or Milligan Street. This would not require as much work as installing new substation transformers with a 22 kV rated secondary winding.

However, much of the existing equipment within the Perth CBD Boundary is already rated to 22 kV. Almost half of the distribution cables and an even higher percentage of the switchgear is capable of operating at this higher voltage [16], [17]. This is a result of a holistic review undertaken by Western Power comparing economies of scales across the entire Western Power Network. It was found that standardizing on 22 kV ready gear created savings in design, inventory, procurement and other metrics which outweighed the small benefits associated with using slightly smaller and cheaper 11 kV cables. It should be noted, however, that most of the existing distribution transformers in the Perth CBD Boundary are not 22 kV ready and would require replacement should the distribution voltage be changed. Further detail is provided in the SKM report East Perth and CBD Load Area Development Report [3].

More practical considerations should also be taken into account. The Perth CBD Boundary is already a heavily congested area and it will become increasingly difficult to find new cable routes for the circuits required to supply power. A migration to 22 kV would not only require fewer cables, but could help replace the existing number of cables and de-congest the cable routes. Additionally, installation of up to 80 distribution cables, with many travelling in closely packed routes, may have a detrimental effect on the ability of the cable to carry current. A simplified cable rating study was undertaken, modelling seven 22 kV cables and fourteen 11 kV cables on the assumption that 22 kV cables can carry twice as much current. The study showed that fourteen 11 kV cables installed in close proximity were able to carry 70 MVA whereas seven 22 kV cables installed in close proximity were able to carry 86 MVA. This equates to 5 MVA at 11 kV versus 12.2 MVA at 22 kV. It can be seen that less than half the number of 22 kV cables would be required to carry the same amount of power as 11 kV cables. Appendix C provides more information on the cable rating study.

Cost of Transitioning Now vs. As-Required Asset Replacement

A holistic assessment was undertaken to analyse the cost associated with migrating the distribution network at Milligan Street and Hay Street to 22 kV immediately versus a staged replacement driven by asset condition. For the purposes of this study, it was assumed that Milligan Street would require to be rebuilt by 2025, taking approximately 7 years. Similarly, Hay Street would require to be rebuilt around the same time. The actual timings of the required rebuilds are assessed in the East Perth and CBD Load Area Development Report [3].

Based on asset age and condition data, more than 150 distribution transformers, 18.32 km of 11 kV cable and 160 RMUs would require replacement at Milligan Street. Similarly for Hay Street, more than 150 distribution transformers, 22.65 km of 11 kV cable and 156 RMUs would require replacement. In addition, the existing switchboards at Hay Street and Milligan Street would require replacement due to deteriorating asset condition. It was assumed that an average of 4 RMUs were connected to each feeder. Costs for the various network elements were compiled using Western Power's Distribution and Quotation Management system (DQM) and the AA3 cost building blocks and a total cost at both Milligan Street and Hay Street was calculated. The two scenarios described above, replacement of all equipment now versus replacement as-required, resulted in a significant cost savings of almost $18 million should the migration be staged on an as-required basis instead of all at once.

- **Table 10 Cost Comparison of Voltage Migration Timing**

Option	Capital Cost	Net Present Cost
Replacement Now	$71.05M	$71.05M[9]
As-Required	$71.05M	$53.43M[10]

It is important to note the above calculation does not fully consider the impact of a voltage migration on the existing DTC. Further consideration would be required concerning the impact on the surrounding substations not migrating to 22 kV (i.e. Cook Street) and how that would be managed. Detailed assessments may indicate retaining the interconnection between sites and utilising 22/11 kV transformers to facilitate load transfers if required. Alternatively, the DTC between these sites may be severed, looping back feeders to the substations of origin (i.e. two feeder pairs connected between Cook Street and Milligan Street would be severed), however this would still require the same number of switches at each substation and not serve to reduce the cable exit congestion issues presently experienced.

Taking all of this into consideration, the best way forward may be a combination of both voltages. That is to say, continue to utilise 11 kV in the wider CBD Load Area and implement 22 kV within the Perth CBD Boundary upon retirement of existing substations. In the interim, 22/11 kV transformers could be installed to interface between the two voltages, effectively operating two different distribution networks in parallel until such time as a full migration to 22 kV could be achieved through asset replacement. This would allow for a natural progression to 22 kV after the assets have reached the end of their service life. It should be noted, the calculation provided above does not take into consideration the existing interconnections between the Perth CBD Boundary sites and the surrounding substations. Furthermore, the calculation is based on total length of cables installed and does not differentiate between those existing assets that are already 22 kV ready. Though significant cost savings can be demonstrated in this calculation, it is recommended to undertake a more thorough distribution investigation to work out asset replacement timings and a clearer migration strategy to determine if 11 or 22 kV should be the operating voltage for the Perth CBD Boundary.

---

[9] The NPC for "Replacement Now" is the same as the total cost due to no savings being realised through deferral of equipment replacement.

[10] The NPC was calculated using the standard Western Power discount rate spread over the years during which asset replacement was required for the various network elements. This cost is indicative only as timings of the substation rebuilds have been assumed to be the same. In reality, rebuilding both substations simultaneously may not be possible, thereby changing the indicative savings shown.

3.4.3. Introduction of 33 kV into the Perth CBD Boundary

An alternative operating voltage that has been considered is 33 kV. Similar to 22 kV, a 33 kV cable is capable of carrying significantly more power than the existing 11 kV cables, upwards of 30 MVA at the larger conductor sizes (Figure 10 - Section 3.4.2). In addition, even fewer cables would be required to supply the same amount of power as 11 or 22 kV. This could help decongest the area within the Perth CBD Boundary and open up existing route corridors for more cables as additional load materialises.

Though 33 kV may seem like a good choice for the Perth CBD Boundary due to the amount of load that could be carried on each distribution cable, practical considerations may limit a full conversion. The load density within the Perth CBD Boundary does not require cables with such a large current carrying capability and the existing equipment in the Perth CBD Boundary is not rated for 33 kV. A shift in the voltage level would result in replacement of nearly all existing feeder cables, switchboards, RMUs and distribution transformers (effectively doubling the expenditure). In addition, no transformers at zone substations have secondary windings rated to 33 kV, meaning these transformers would need to be replaced with transformers with appropriately rated secondary windings or have 11/33 kV step-up transformers installed until the end of their service life. Procurement of 132/33 kV transformers would also prove an issue as the size of transformer required would be unique to the CBD Load Area[11]. While the transformers may not be unmanageable, the amount of works required to replace the rest of the equipment effectively rules out a transition to 33 kV at this time.

Another consideration is the relative cost of switchgear, RMUs and distribution transformers at 33 kV versus 22 kV. According to Western Power's DQM system, the relative cost of RMUs and associated switchgear for an operating voltage of 33 kV are approximately one and a half times (1.5x) the cost of similar equipment at 22 kV. The cost difference between distribution transformers is almost negligible. Coupled with the amount of equipment not rated to 33 kV, this would amount to a rather large investment requiring replacement of nearly every piece of distribution equipment in the Perth CBD Boundary at a higher cost premium than selecting 22 kV equipment.

Further consideration may be given to installing a 33 kV ring around the perimeter of the Perth CBD Boundary. This ring would be used to supply new major block loads whilst providing strategic support to the 11 kV network. However, this option has been discounted due to the associated practical limitations. Construction of a 33 kV ring would require a significant amount of land as not all sites currently owned by Western Power are large enough to accommodate additional transformers. Land availability could be an issue and would potentially take significant time to procure dependant on the location and size required. Additionally, a number of interfaces would be required to support the 11 kV network, thereby creating sites with multiple voltage levels and

---

[11] It should be noted 132/33 kV transformers are used elsewhere in the Western Power Network. However, the transformers are all rated to a much lower MVA than what would be required to supply the CBD Load Area.

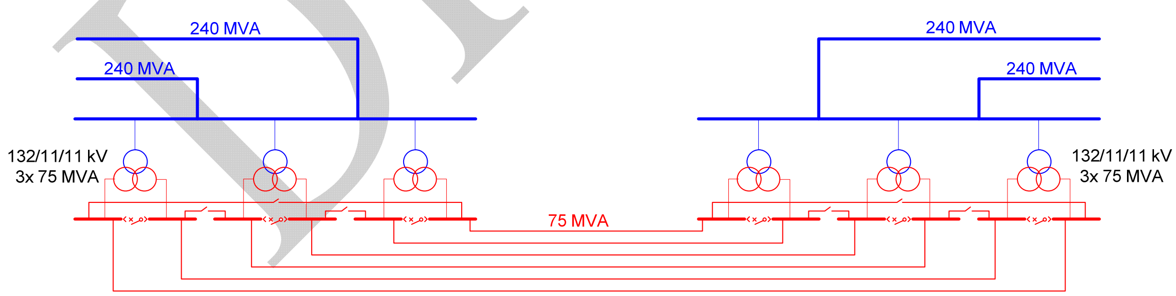
potentially split 33 and 11 kV switchboards. The biggest argument against installation of a 33 kV ring, however, is that the current load demand and forecasted growth is not enough to support the operating voltage and the network may remain underutilised for a significant number of years beyond the 25 year scope of this assessment.

From the above analysis, it is noted that an increase in the distribution operating voltage to 22 kV could provide benefits recognising that further investigation is required into how to reduce the cable congestion issue that exists at 11 kV and increase feeder loading should a distribution strategy find 11 kV to be the more economic option. This is discussed more in the East Perth and CBD Load Area Development Report [3].

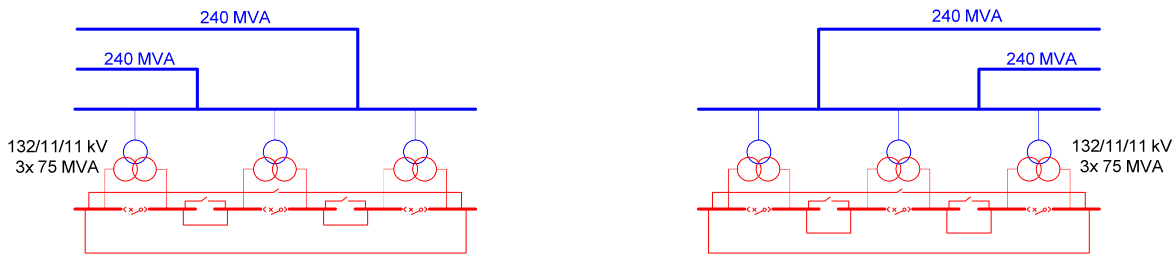
3.5. Distribution Transfer Capacity vs. Transmission Interconnection

As mentioned in Section 2.1.3, the Perth CBD Boundary has an increased requirement for security and reliability compared to the wider Western Power Network. Due to this requirement, it becomes necessary to explore different transmission and distribution network architectures that meet the required level of reliability whilst potentially identifying improvements in the existing architecture. Using the greenfield approach identified at the beginning of this report, different distribution architectures, and their associated transmission architectures, were assessed against the N-2 criterion to determine the most efficient network architecture.

For the purposes of this assessment, two substations consisting of three 75 MVA, 132/11/11 kV transformers, located 1 km from each other, were used. Both sites have two incoming 132 kV circuits supplying the site with a load demand of 150 MVA. It should be noted the transformers could be replaced with 132/22 kV transformers, however as the existing Western Power Network utilises these three winding transformers in the Perth CBD Boundary, the analysis used this as a basis. In order to supply local load, two options were developed; interconnecting the substations via distribution feeders between sites (Option 1), similar to the existing DTC, or radial distribution feeders looping back to different switchboards at the same substation (Option 2). Figure 11 and Figure 12 show the two different options explored.



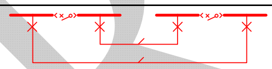
- **Figure 11 Basic Distribution Network Options - Interconnected Substations**



■ **Figure 12 Basic Distribution Network Options - Looped Feeders**

In order to supply the total load demand at each site, the same number of distribution feeders would be required regardless of the option chosen. For example, looping feeders back to different switchboards would require thirty 11 kV distribution feeders, at 5 MVA per feeder, at each site. If 22 kV feeders were required (assuming appropriately configured transformers) this would amount to fifteen distribution feeders at 10 MVA per feeder. The feeders would have a normally open point in case of a feeder fault, supplying the required N-1 security as per the Technical Rules. By comparison, should the sites be interconnected at distribution level, thirty 11 kV feeder pairs would require to be established (or fifteen 22 kV feeder pairs), with each side of the feeder being loaded to 2.5 MVA (or 5 MVA at 22 kV) to ensure N-1 security at the distribution level. The distribution interconnection would be limited to only supporting 75 MVA in the first instance, or enough to supply the load of one failed transformer. Table 11 shows a comparison of these options.

■ **Table 11 Comparison of Distribution Options**

Option	Number of 11 kV Bays Required	Load per Arrangement	N-2 Support
1	 2 per site	5 MVA per site	2.5 MVA DTC per feeder pair
2	 2 per site	5 MVA per site	0

With no further analysis, it can be seen that both options comply with the Technical Rules at the distribution level and require the same number of circuit breakers and distribution feeders at each site. However, for an N-2 event at the transmission level Option 1 provides support that cannot be provided under the network arrangement for Option 2. This demonstrates that, from a greenfield approach, interconnecting substations at the distribution level has more network benefits.

Assessing the options against the transmission criteria for N-1 and N-2, it can be readily seen that an N-1 contingency is catered for by installing three transformers at each site, thereby ensuring 150 MVA of N-1 capacity. Should a transformer fault occur the remaining two transformers can still supply the total load demand without requiring extra support.

The more stringent requirement is the N-2 criterion. Each substation must satisfy this criterion for any credible double contingency event on the transmission network. It can be seen the worst case credible contingencies would be loss of both 132 kV incoming circuits at one site, or loss of two transformers at one site. Any other combination of contingencies is supported under either network configuration.

The options were assessed against the N-2 criterion with a target maximum supportable demand of 300 MVA, the total load demand for the two sites combined. Looking at the worst case N-2 contingencies, Table 12 shows a comparison of the equipment required at each site to maintain N-2 compliance.

- **Table 12 Comparison of Transmission Options for an N-2 Event**

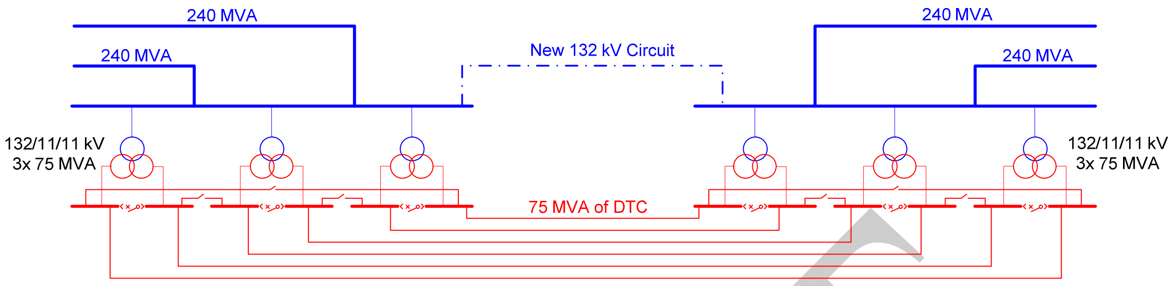
N-2 Event	Option	Number of Transformers per Site	Available DTC	Additional Transmission Circuits Required
Loss of two transformers at one site	1	3	75 MVA	0
	2	4	0 MVA	0
Loss of two incoming transmission circuits at one site	1	3	75 MVA	1
	2	3	0 MVA	1

As can be seen in the table, for loss of two transformers at one site, Option 1 does not require any additional transformers or transmission cables. This is due to the remaining transformer supplying 75 MVA of load and the existing DTC between the sites supplying the remaining 75 MVA. The maximum supportable demand for this option meets the target of 300 MVA. Option 2, however, requires four transformers at each site instead of three as there is not additional support via the distribution network. Should a fourth transformer be installed at both sites, the maximum supportable demand also meets the target of 300 MVA as loss of two transformers would result in the remaining two transformers supplying the full 150 MVA of load at the site.

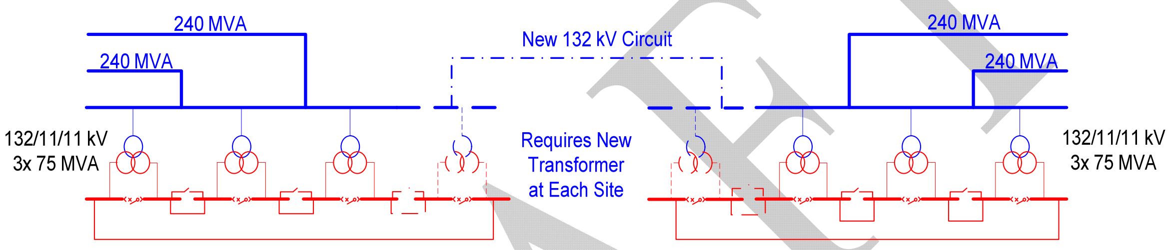
For the other worst credible contingency, loss of both incoming circuits to one site, it can be seen that the maximum supportable demand for Option 1 is limited by the installed capacity of the remaining three transformers or 225 MVA. This is a shortfall of 75 MVA and would be non-compliant with the Technical Rules. As the installation of additional distribution cables would not be required unless new load needed to be connected, the remaining alternative is to install a transmission circuit between the sites, thereby ensuring continued supply to the transformers. This would allow a maximum supportable demand of 300 MVA between the two sites. Similarly for Option 2, the maximum supportable demand would be 150 MVA as there is no distribution interconnection between sites to support any load. The same conclusion can be drawn that a transmission circuit installed between sites would increase the maximum supportable demand to 300 MVA. No additional transformers would be required as the load at each site is 150 MVA and can be supported by the existing three transformer arrangement.

To summarise, in order to maintain N-2 compliance for all credible contingencies; Option 1 would require three transformers at each site, 75 MVA of DTC and one additional transmission circuit; Option 2 would require four transformers at each site and one additional transmission circuit.

Figure 13 and Figure 14 show the transmission and distribution architecture required for both options to ensure N-2 compliance.



- **Figure 13 Option 1 Transmission N-2 Requirements**



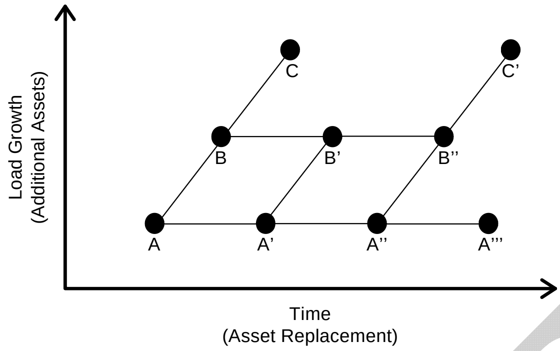
- **Figure 14 Option 2 Transmission N-2 Requirements**

Applying the developed options to the Perth CBD Boundary, it can be seen that Option 1 is similar to the existing network arrangement, with the main difference being the additional 132 kV transmission circuit. A simplified economic comparison between the two options shows Option 1 to be a lower cost as the DTC is already installed and would be a sunk cost. The requirement of only the additional transmission cable, versus the requirement for two new transformers and a transmission cable for Option 2, can readily be seen to require much less investment.

The ideas presented in this analysis are further explored within the East Perth and CBD Load Area Development Report [3]. The additional analysis considers the more practical network limitations such as cable congestion, availability of feeder terminations and other issues whilst demonstrating project specific justification for the use of the distribution network or transmission network to ensure the required level of reliability.

3.5.1. Deployability

Another measure by which to rank the options is by their respective deployability. This will take into account various factors such as size of the substation, number of sites required, number of required easements and ability to stage each option. At a high level, this can help aid the selection process as some options may be highlighted as not feasible due to too many constraints. Figure 15 indicates a typical deployability road map.



- **Figure 15 Deployability Road Map**

The deployability road map is essentially a map of load growth over a period of time. Each axis can be interpreted further by associating a requirement for additional assets, meaning increased capital expenditure, with load growth and natural asset replacement with time. In this sense, a horizontal move in the figure above would indicate the retirement and replacement of an asset, which in this case could be retirement of an existing 132/11/11 kV transformer and replacing with a 132/22 kV transformer. A vertical shift in the figure would imply installation of additional assets to meet the increased load demand (i.e. installation of an additional transformer). The best network progression would be one that moves horizontally as opposed to vertically as this would indicate no additional expenditure other than what is required to replace existing assets. In practice, however, as load growth increases a vertical move will be required at some stage and the later this can be deferred (i.e. a vertical shift at B' rather than B) the better.

As the existing sites within the Perth CBD boundary reach retirement, a staged replacement program may be developed. The existing 132/11/11 kV transformers could be replaced by 132/22 or 11 kV re-connectable transformers. This would enable continued supply to the existing 11 kV network, connecting the transformer as 132/11 kV initially, while allowing a fundamental shift toward 22 kV by reconnecting the transformer secondary to 22 kV when appropriate. When the load demand exceeds the existing network capability, a new site could be established with 132/22 kV transformers thus extending the new 22 kV network. To relate this to Figure 15, the new site would represent a vertical shift (i.e. from A' to B'). Interconnections could be established at 22 kV as necessary. As more load demand materialises, additional transformers could be installed at the new site.

Deployability will be considered as part of the project specific analysis undertaken in the East Perth and CBD Load Area Development Report [3].

3.6. Application to the Perth CBD Boundary

As mentioned in Section 3.2, the load demand within the Perth CBD Boundary is expected to increase by approximately 240 MVA by 2036. In order to address this increase in demand, a number of different distribution network architecture options have been developed. The approach taken for this assessment was to look at the load as it if were being supplied to a greenfield site, i.e. undeveloped land within the Perth CBD Boundary with the potential to be developed in the most beneficial manner. Various architectures deployed in other major CBDs, both in Australia and further abroad, were researched to determine if those architectures were suitable and how they may be adapted to supply 240 MVA. The options consider different distribution voltages of 11 kV, 22 kV or 33 kV, utilisation of a DTC scheme similar to the present Perth CBD Boundary configuration. Analysis in Appendix D applies the preceding discussions of this section to the CBD boundary on the basis of a load growth to 240 MVA by 2036.

The analysis supports the following recommendations:

- Benefits can be realised by a migration to 22 kV.
- Continuing with DTC only to achieve N-2 at transmission level is not recommended.
- Opportunities will exist to reduce interruption time for an N-1 event (in some cases bumpless N-1 operation may be possible) in an economically viable option.
- Opportunities exist for increased distribution cable utilisation through the implementation of teeing into existing circuits. This may provide an opportunity for a staged transition to 22 kV.

Though the initial evaluation has been applied to a greenfield approach, it is prudent to apply the argument to the existing Perth CBD Boundary. Section 3.4.1 discusses the relative merits of a transition to 22 kV, versus retention of the existing 11 kV, however this may not be practical. Feeder catchment areas should be taken into consideration as load growth in the individual areas supported by zone substations may not require an increased distribution voltage. Additionally, some existing sites have recently installed equipment, such as 132/11/11 kV transformers, that are not capable of operating at 22 kV. These assets would require being written-off early as they are still within their expected service life. It is possible these assets may be relocated elsewhere in the Western Power Network, and this should also be a consideration. At present, this applies to both Cook Street and Joel Terrace as the 132/11/11 kV transformers have been installed in the recent past.

Ultimately, site specific factors should be taken into account, such as those mentioned above, when determining whether or not to migrate the distribution voltage to 22 kV. As the Perth CBD Boundary continues to expand, further study should be undertaken on a case by case basis to determine the requirement for a higher distribution voltage.

4. Transmission Network Architecture

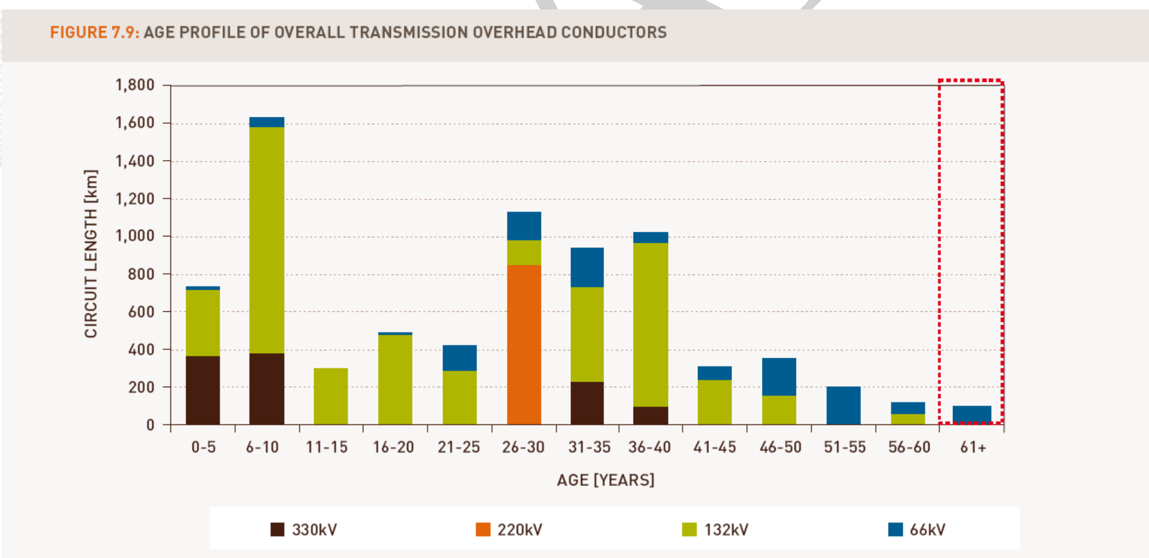
4.1. Existing Network Architecture

4.1.1. Current Transmission Voltage

The existing Western Power transmission network supplying the CBD Load Area and surrounding areas is composed of a mix of 66 kV and 132 kV network assets, many of which were installed in the 1950s and 1960s. The 66 kV network was used as the principal transmission supply voltage for many primary substations, including for those supplied from East Perth and Western Terminal although some, such as Hay and Milligan Street in the Perth CBD Boundary were directly supplied at 132 kV.

By the end of the 1970s, 330 kV transmission lines and associated terminal substations had been added to supply growing electrical demand across the wider network. The 330 kV lines allowed transfer of power from regional, mainly southern, generation to metropolitan load centres further north, where the bulk of the network demand was located.

In the 1980s, construction and development of mining customers and resource projects in the Goldfields region of Western Australia resulted in the development of 665 km of 220 kV overhead transmission line between Muja and Kalgoorlie, also supplying other towns and developments along the route.

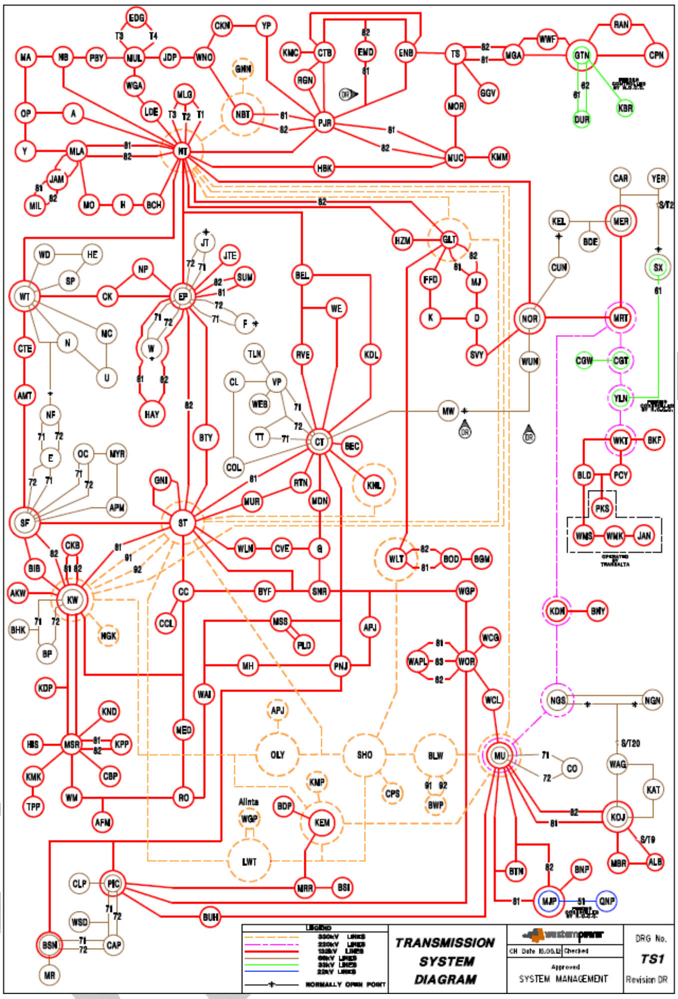


▪ **Figure 16 Reproduction of Figure 7.9 from 2011-2017 Network Management Plan**

An illustration of the broad age profile for Western Power transmission system assets is shown in the 2011 – 2017 Network Management Plan [18] in Figure 7.9, reproduced in Figure 16. Whilst this figure relates specifically to overhead line conductors it is nonetheless representative of the broad Western Power Network transmission system development over the last 60 years.

4.1.2. Current Architecture

The existing SWIN transmission system is shown in Figure 17 below.



- **Figure 17 Existing SWIN Transmission System**

It is evident from review of Figure 17 that the existing transmission system is characterised by a highly meshed 132 kV network with 330 kV transmission lines in parallel along many power corridors. As a result there is heavy reliance on the 132 kV transmission lines to transfer power directly from generation alongside the 330 kV network.

The TNDP [19] details how recent studies conducted by Western Power indicate that around 700 MW of power is flowing through the 132 kV network in parallel with existing 330 kV lines. As a result, the utilisation (loading) of existing 330 kV transmission lines is lower than would otherwise be expected and the loading of the meshed 132 kV (and to an extent 66 kV) network much higher than would be expected, in some cases reaching the thermal capacity rating of the assets. Specific problems identified in the NMP include:

- overloading of the meshed 132 kV network under contingency conditions

- need for increased reactive power support at 66 kV and 132 kV to maintain an adequate system voltage profile, particularly under contingency conditions
- high 132 kV fault levels across the system, particularly at terminal substations and also at some zone substations
- difficulties managing 132 kV power flows to within circuit ratings due to the meshed network configuration, particularly under contingency conditions
- challenges during network planning, network operation and maintenance activities due to the highly sensitive nature of line power flows to network impedance changes (as a result of planned and unplanned outages)

The existing network architecture does however have some merits:

- achieves high utilisation of 132 kV network assets
- allows high reliability of supply to substations with minimal switching times

However, while it is accepted that the planning, designing and operating a 132 kV transmission system as a meshed network can provide a suitable means by which to enhance the utilisation of existing assets and provide a low cost, secure supply to customers, this is generally only true over the short to medium term. Eventually, as higher transmission system voltages are added and asset utilisation is increased and potentially large changes in directional power flows experienced (to accommodate varying generation types, technologies and locations), the advantages associated with a meshed network configuration are outweighed by the drawbacks. It is evident from the NMP and SKM's experience and familiarity with the Western Power system that this point has already been reached. As a result, we consider that future network planning and reinforcement projects within the Western Power Network, particularly in the highly meshed areas between South Fremantle, Southern Terminal, Cannington Terminal and Northern Terminal substations, should give consideration to fragmenting the existing 132 kV meshed network into the more radialised networks typically experienced at this voltage level.

In relation to the CBD Load Area, while this is presently supplied from three terminal substations (Northern, Western and Southern), additional circuit infeeds to the CBD Load Area will likely be required over the medium to long term to cater for expected demand growth. Consideration will need to be given to the strategic aim to split up the existing meshed 132 kV network. The alternative, if additional circuits supplying the CBD Load Area are taken from terminal substations currently providing supply for alternative locations (e.g. Cannington Terminal, Guildford Terminal) without changes to the underlying network architecture, would be to effectively increase the meshed nature of the network, thereby exacerbating the problems outlined previously. As a result, it is recommended when future supply configurations are being considered for the CBD Load Area that specific consideration is given to flexibility of the resulting supply arrangements and necessary modifications or revisions also considered (e.g. splitting terminal substation busbars, introducing network open points and special protection schemes, etc) to reduce the meshed nature of the network whilst still providing cost effective and reliable customer supplies.

4.2. Consideration of Other TNSP Networks

In order to provide a reference point to measure potential future developments in the CBD Load Area a review has been performed of the characteristics of transmission systems supplying other city areas. This is shown in Table 13 for a range of Australian and UK cities.

- **Table 13 TNSP Comparison for Other CBDs**

City	2011 Summer Max Demand	Customers Served	Transmission Voltage (kV)	Number of Substations
Perth	0.42 GW	44,000[12]	132 & 66	8 Zone Substations
Sydney	0.53 GW	321,000	330 & 132	31 Zone Substations
Melbourne	0.55 GW	313,000	330[13] & 220 & 66	13 Zone Substations
Brisbane	0.42 GW	Not Available	275 & 110	10 Zone Substations
London City	1.74 GW	720,000	400 & 275 & 132	23 Zone substations
Manchester	0.65 GW	327,000	275 & 132	10 Zone Substations

Whilst Table 13 does not contain an exhaustive list of all Australian or UK cities it is evident from this limited review that most city load areas, of a similar size to Perth, utilise multiple transmission system voltages in order to supply zone substations, in most cases with one voltage level higher than 132 kV. This suggests that as the CBD Load Area continues to grow, potentially reaching around 0.7 GW by 2035, it will be necessary to overlay the existing 132 kV transmission network supplying the CBD Load Area with a higher voltage in order to enable area electricity demand to be supplied economically and efficiently.

The requirement for a higher (than 132 kV) transmission system voltage to supply the CBD Load Area is examined further in the next subsection of this report.

4.3. Future Network Architecture Concepts

4.3.1. Transmission Voltage

Rationalisation of 66 kV Equipment

As outlined in Section 4.1.1, a significant proportion of the total existing 66 kV network assets were installed in the 1950s and 60s. As a result, the vast majority of 66 kV network assets still in service across the Western Power Network are more than 40 years old. Relative to this study, the load areas of interest which still retain 66 kV transmission assets include:

---

[12] Provided by Western Power's System Forecasting team. Note within the Perth CBD Boundary a single building, regardless of size, can be classed as one customer. This may go some way in identifying the vast difference in customers served between Perth and the Australian East Coast.

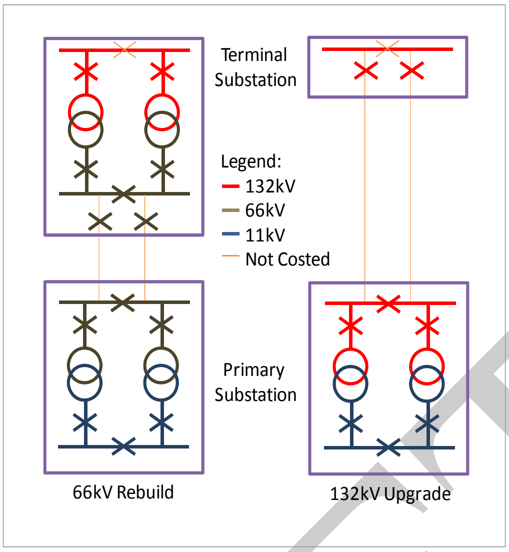
[13] 330 kV exists only at one substation South Morang 500/330/220 kV. This site is located to the North and West of the Greater Melbourne & Geelong area.

1) East Perth
2) Western Terminal
3) Cannington Terminal
4) South Fremantle

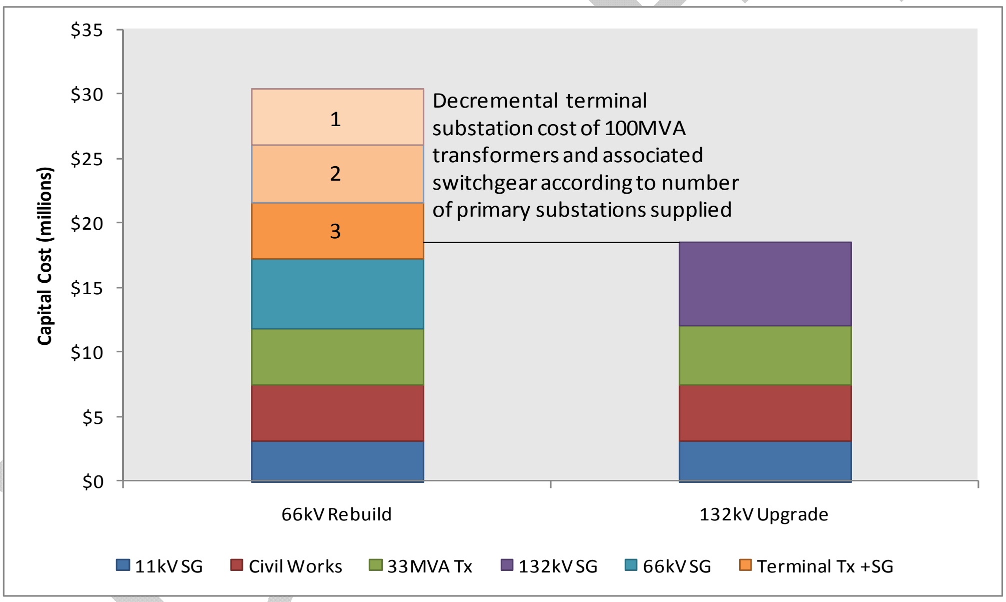
Given that specific 66 kV rated electrical equipment (i.e. switchgear, cables, overhead line designs, etc) is no longer commonly installed across electrical networks in many jurisdictions (includes the UK, Middle East and Australia) as a result of higher rated 33 kV equipment being available in conjunction with lower 132 kV equipment costs, it is expected that if 66 kV equipment needs to be replaced, 132 kV will be adopted. This is true for overhead line designs, underground cables, switchgear and even primary substation transformers where reconfigurable connections are also available. This has broadly been Western Power practice for the past several years.

As a result, across the Western Power Network the principal driver underpinning the removal of the existing 66 kV assets is typically the age and condition of the supplying terminal substation 132/66 kV transformers. These items of plant have a present capital cost in the region of $[redacted]M, with two or more usually being required at terminal substations to meet N-1-1 requirements. Consequently, whilst some 66 kV equipment that has reached the end of useful life can be easily replaced with equivalent 132 kV equipment and not result in potentially future stranded assets, for terminal substation transformers there is little option but to replace them outright, either with new or refurbished units. To illustrate this concept a costing analysis has been undertaken using Western Power cost building blocks to calculate the cost of a 2 x 33 MVA outdoor primary substation at both 66 kV and 132 kV. Note that the former includes the cost of the 132/66 kV transformers at the terminal substation plus the additional switchgear involved. Costs for overhead line and underground cables have been neglected as these are expected to be the same for both options given like for like distances and planning/consenting issues. Civil and structures costs are also the same for both options reflecting the fact that site outdoor structures will be virtually identical plus the substation building will also contain the same equipment (e.g. 11 kV switchgear panels, protection, metering, comms, etc) in both cases.

Single line diagrams of the indicative terminal and primary substations being considered are shown in Figure 18 with the result of the cost analysis presented in Figure 19. It is noted that reduced switchgear systems can be utilised, however such an indicative design has been presented to give a fair cost comparison.



▪ **Figure 18 Single Line Diagram for 66 kV and 132 kV Substation Cost Comparison**



▪ **Figure 19 Cost Comparison of 66 kV and 132 kV Substation Designs**

It is evident from Figure 19 that once the cost of the supplying terminal substation 132/66 kV transformers and accompanying switchgear is included, the effective cost of supplying a 33 MVA 11 (22) kV substation is actually higher at 66 kV than 132 kV, even when the maximum number of substations per pair of 132/66 kV transformers is considered. This demonstrates that there is likely to be considerable benefit in assessing 132 kV rebuild options for 66 kV network assets that have reached the end of asset life. As a result, it is expected that once the existing 132/66 kV transformers at the four terminal substations outlined reach their end of life, then the 66 kV transmission voltage should be abandoned. Based on existing asset ages and conditions this is expected to be around 2024 at Western Terminal, 2018 at East Perth, 2020 at South Fremantle and 2020 at Cannington Terminal. It should be noted the analysis above does not consider building costs which would be required for the 132 kV upgrade. This is expected to be a marginal cost.

Limited Application of 220 kV

Section 4.1.1 describes how 665 km of 220 kV overhead transmission line was constructed between Muja and Kalgoorlie in the 1980s as a result of mining and resource projects. Although 330 kV was already an established transmission voltage within the Western Power Network, 220 kV was chosen to supply Kalgoorlie as it could provide the required connection capacity at a lower cost. 220 kV was also cheaper to connect additional towns and developments along the line route than 330 kV.

However, whilst it is expected that the existing 220 kV assets can remain on the Western Power Network for another 20 to 30 years, Western Power do not expect to install any further 220 kV assets unless directly required in relation to the existing Eastern Goldfields connection or technically required for another connection. As a result, in relation to future network development it is unlikely that 220 kV would be considered as a higher transmission system voltage[14].

Comparison of 132 kV & 330 kV CBD Load Area Supplies

Previous reports have been written concerning the construction of a new 330 kV terminal substation in the CBD Load Area [20], [21]. The reports focused on possible locations for a 330 kV injection point based on existing Western Power landholdings. At the time of the original analysis, both reports indicated that 330 kV will not be required until beyond 2022. Additionally, both reports indicated no requirement for additional 132 kV transmission infeeds to the CBD Load Area before 2022.

To support the findings of this earlier work, that a 330 kV terminal station to supply CBD Load Area is not required in the short to medium term (within 15 years), SKM has performed an assessment examining both the economics and environmental/consenting impact of alternative supply options to the CBD Load Area. This high level analysis considers the alternative circuit options to feed the CBD Load Area, including both 132 kV and 330 kV metro specification overhead line options[15].

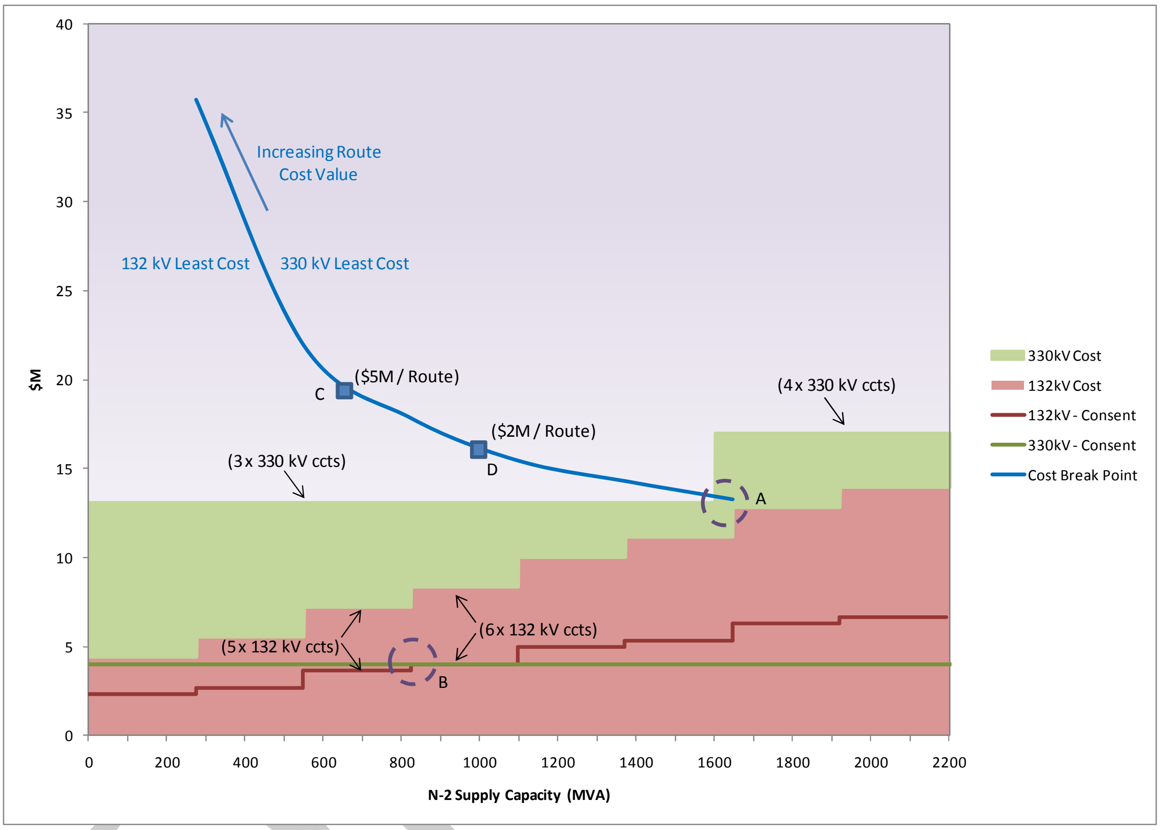
It should be noted the costing analysis has been performed for overhead lines only and for 330 kV options does not include the cost of 330/132 kV transformers or 330 kV switchgear. Although this additional equipment would add significantly to the costs of the 330 kV option, it has been excluded from this assessment as it is considered to be required in both options i.e. to supply the 132 kV line at the sending end or at the terminal site at the end of the 330 kV line to provide a 132 kV supply.

---

[14] This statement is subject to proving economically efficient as per current ERA NFIT rules.

[15] This analysis does not consider the impact of transmission load flows and is based on the assumption that the total transmission circuit capacity under each option can be utilised fully.

The results of the analysis are shown in Figure 20 and, for the purposes of this example are calculated on a notional 10 km circuit basis whilst providing an N-2 level of supply – the highest applicable standard for the Perth CBD Boundary. The capacity of each 132 kV circuit is assumed as 274 MVA (single Venus AAC 132 kV conductor per phase) and each 330 kV circuit 1600 MVA (twin DR-HAL 840 mm^2 conductor per phase) based on existing Western Power transmission overhead line designs.



■ **Figure 20 Economic and Environment Assessment of CBD Area Supply Options**

From Figure 20 it is evident that based entirely on transmission line capital cost, 132 kV will always provide the lowest cost means by which to supply a given load area demand. Only once the demand reaches around 1,600 MVA (point A) could 330 kV potentially have a comparable transmission line cost (based on the line ratings considered) to 132 kV.

However, one aspect that is not captured in the economic assessment is the environmental, planning and consenting impact associated with the alternative line designs. For example, to provide a secure N-2 supply for a demand of 1,000 MW (1,053 MVA at 0.95 p.f.), based on the existing Western Power line ratings, six 132 kV circuits would be required in comparison with three 330 kV circuits. Whilst the 330 kV circuits would be considerably more expensive than the 132 kV option, there is an intrinsic but fundamental community and consenting benefit associated with such options through the significantly lower number of circuits required. True, each individual 330 kV circuit (or double circuit) may be expected to have a slightly poorer consenting/environmental rating than the equivalent 132 kV circuit (as towers/poles are fundamentally larger to accommodate additional conductors and higher required line clearances), however the net overall environmental benefit by having fewer circuits is undeniable.

To illustrate this point a comparative environment/consenting rating for the two CBD Load Area line options has been provided based on input received from the Western Power Environment, Community and Approvals (ECA) team. The ratings for the alternative line options have been provided as a comparative value in relation to a 132 kV single circuit wood pole line design – considered to have the lowest overall ECA impact for a new overhead line route given the lower profile nature of the line design with significantly less visual intrusion.

From point B in Figure 20, it is evident that the 132 kV overhead line supply option (with 6 circuits) has the same ECA impact rating as the 330 kV option with 3 circuits[16]. This illustrates that from an ECA perspective, once the CBD Load Area demand surpasses 822 MVA (3 x 274 MVA), it would be preferable to use 330 kV instead of 132 kV. It is accepted that this is somewhat of a simplistic assessment and the true cost of the 330 kV options will be greater than outlined in Figure 20 whilst the 132 kV option will actually be lower than indicated on account of there being five 132 kV circuits already in service supplying the CBD Load Area. However, it does illustrate that from a greenfield development perspective with a demand of around 800 MVA, 330 kV may be the most environmentally efficient transmission line option.

An alternative approach is to consider the “value” or “broader community cost” associated with individual transmission routes into the CBD Load Area, there being a physical restriction on the number of routes available. Several approaches could be adopted to represent the “value” associated with each individual transmission line route, however for the purpose of this assessment an arbitrary value of between $0.1M and $10M per route has been included in the economic calculation. The resulting breakeven point between the alternative 132 kV and 330 kV transmission line options are shown by the blue trade-off line in Figure 20. The lower cost end of the blue line (circa 1600 MVA) corresponds to point A already discussed above, although now including an additional cost of $0.1M per transmission route into the CBD Load Area. The higher cost end (circa 300 MVA) is the cost trade-off point with a value per transmission route into the CBD Load Area of $10M in addition to the capital cost of the transmission lines. Points C and D correspond to route values of $5M and $2M respectively, again in addition to the capital cost of the transmission lines. Essentially, the trade-off point A moves along the trade-off frontier through points D and C as the cost per route increases.

From this assessment of transmission route “value” it is evident that for a notional route value of between $2M and $5M per route (points D and C respectively), the economic breakeven point

---

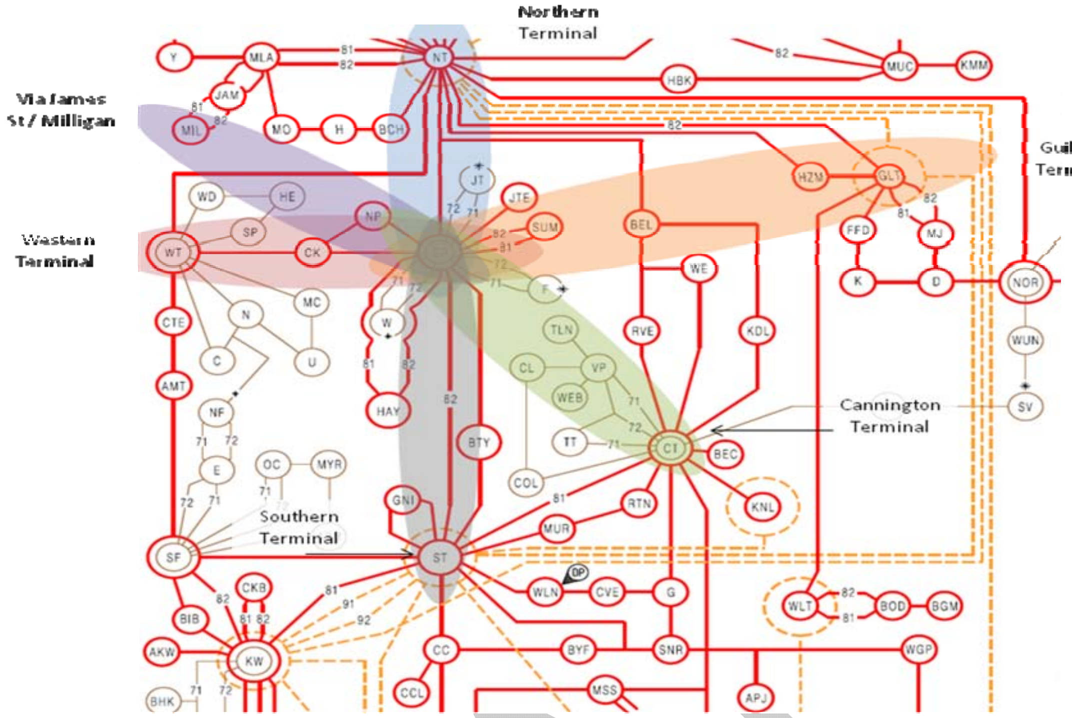
[16] Note there is no step-change shown in the consenting value for the 330 kV transmission option when moving from double circuit and single circuit 330 kV transmission lines to two double circuit 330 kV lines. This is because the perceived additional environmental impact is likely to be small if the single circuit 330 kV tower is converted to a double circuit 330 kV tower design.

between alternative 132 kV and 330 kV transmission line configurations could fall broadly between 600 MVA and 1,000 MVA. This area demand range also encompasses the circa 800 MVA (point B) trade-off point from the environment analysis. Collectively these assessments would appear to suggest that once the CBD Load Area demand reaches 700-800 MW (MVA), around 2030 to 2035 based on the current demand forecast, that it may be appropriate to consider a transition to 330 kV to rationalise area supplies and balance economic and environment considerations with future asset replacement requirements.

It can therefore be concluded, on the basis of the above in addition to the findings of previous studies, that in the short to medium term, i.e. within the next 15 years, there is no requirement for a new 330 kV terminal substation for CBD Load Area supplies. 132 kV will provide sufficient circuit capacity into the CBD Load Area to cater for expected future demand growth. That said, it is likely that 330 kV will be required over the long term as the CBD Load Area demand continues to increase and existing 132 kV assets require replacement due to age and condition. In such a case an opportunity will exist to rationalise the number of 132 kV infeeds to the CBD Load Area (potentially by removing ST-BTY-EP and NT-EP transmission lines once they reach their end of life) allowing the CBD Load Area supplies to be provided by a smaller number of high capacity 330 kV circuits supported with a small number of 132 kV circuits to provide strategic area supply security. As such, it is recommended that when new 132 kV circuits are being provided to the CBD Load Area, consideration should be given to the line construction and if found to be economically justifiable, 330 kV line designs adopted and if necessary operated at 132 kV for an initial period.

4.3.2. Future CBD Supply Options

The existing CBD Load Area supplies are provided via 132 kV circuits from Northern Terminal (including via James St), Western Terminal and Southern Terminal, approximately 14 km, 8 km and 22 km respectively. Obviously these options are also available for future augmentation of the CBD Load Area supplies, as are possible options via Cannington and Guilford Terminal substations – see Figure 21.



- **Figure 21 Illustration of Potential Future CBD Supply Options**

In terms of the broad connection options illustrated in Figure 21 Cannington Terminal is around 13 km from East Perth and Guildford around 18 km from East Perth.

At present the closest 330 kV supply to the CBD Load Area (to East Perth) is Northern Terminal, around 14 km away. However, if as expected Cannington Terminal is upgraded to 330 kV [19] in the next 5-10 years, this will provide a marginally closer 330 kV supply to the CBD Load Area.

An illustration of how some of these potential supply reinforcement options could be used to augment the existing transmission system infeeds into the CBD Load Area are shown in Appendix E in conjunction with accompanying indicative distribution system works.

5. Enabling and Emerging Technologies

5.1. Pit and Duct Systems

As part of this study, a review was conducted of the report entitled “CBD Distribution Cable Plan” [22]. The report was initially written in response to the City of Perth indicating that roadways and footpaths should remain untouched for a period of 15 years after any work has been finished[17]. The City advised that any cables being installed should also install spare ducts as this would limit disruption to the roadways and footpaths.

The report indicated that the Perth CBD Boundary is currently the only Australian Capital City that does not have a pit and duct system for distribution cabling. However, it also indicates that installation of cables in a duct serve to reduce the current ratings, as opposed to direct buried cables or cables installed in air, due to thermal de-loading. The costs associated with construction of the pits required for the pit and duct system vary depending on the approximate area. This is an important consideration as a wider pit would allow for increased spacing, thereby increasing the current ratings of the cables. However, this is only the case if the duct dimensions were also increased. Should the duct dimensions remain the same, the current ratings would remain the same as no additional spacing in the duct would be afforded to increase the rating. The study found that a typical 1.2 m wide pit and duct system consisting of 16 ducts would cost approximately $[redacted]M per km; a 2 m wide pit and duct system would cost more at approximately $[redacted]M per km. By comparison, a cable tunnel would cost the most at approximately $[redacted]M per km [22]. It is assumed that these costs, as of July 2009, are likely to have changed but be proportionally similar, making a pit and duct system a more economically attractive option.

Further consideration should be given to the use of the tunnel. While the economics behind the construction of the tunnel versus installation of a pit and duct system indicate the latter as less expensive, the cost of equipment being installed into the structure once constructed should also be considered. A cable tunnel has the potential to accommodate a transmission circuit whereas a separate duct would be required under the pit and duct system. This adds an extra cost dimension to a pit and duct system that should ultimately be considered.

The economic benefits should also be weighed against the technical benefits provided by a cable tunnel. Installation of a tunnel would allow for an increased number of cables to be carried and potentially higher current ratings on the cables if the tunnel was ventilated [22]. The cable tunnel, however, would require a significantly deeper excavation depth than a pit and duct system.

---

[17] The City of Perth has made this request based on a history of utilities in the area removing road surfaces multiple times a year without a clear strategy for future installation works. Although not an official restriction, it is a guideline which could have potential political and social ramifications if not addressed directly or through improved strategies on cable installation programmes which is not always possible.

With these considerations in mind, a pit and duct system is proposed primarily for the Perth CBD Boundary distribution network. It should be noted, however, that this recommendation should be considered on a project basis as the technical benefits of a tunnel can outweigh the benefits of a pit and duct system, especially if a 132 kV transmission circuit(s) could be accommodated and costs can be shared with other services wishing to use the tunnel. Over the course of this study, Western Power has performed further investigation into the feasibility of a tunnel. The findings of this work will assist with the economic analysis to determine the most cost effective method. Completion of this work should be taken into consideration on a project basis before any decisions are made.

5.2. Demand Management

A key driver for the need for transmission and distribution network augmentation is the increase in peak electricity demand and the reducing load factor over recent years. Electricity demand usually peaks for short periods of time over a few days in the year. This in turn drives capital expenditure as the network must be capable of supplying peak electricity demand. DM comprises of specific measures that can help to reduce peak electricity demand with the aim to defer or avoid investment in network capacity.

As per the ENAC, major transmission or distribution projects or a combination thereof, require consideration of alternative options involving non-network solutions such as DM. Western Power seeks to implement DM solutions wherever it is economically efficient to do so.

As part of the AA2 submission, Western Power included a “D Factor” scheme for approval by the ERA. In essence, only the deferral of approved network augmentation has this pre-agreed funding mechanism. The “D Factor” scheme allows Western Power to finance the cost of DM, irrespective of whether it is operational or capital expenditure, from the savings realised by deferring the related network augmentation to a future date. Furthermore the “D Factor” scheme allows Western Power to recover revenue from such DM investment so that it is no better or worse off financially for having deferred the investment in the network.

The ENAC differentiates between major projects (>$32.7M for transmission and >$10.9M for distribution)[18] and non-major projects. Major projects are subject to the ‘Regulatory Test’ which specifically requires that non-network alternative options be considered. If the non-network solution represents the lowest NPC option, then this option must be adopted.

Non-major projects are not subject to the ‘Regulatory Test’. However, they must satisfy the Network Facilities Investment Test (NFIT) under the Code in order to be included in the regulated asset base. This requires ensuring that the selected option ENAC (subject to NFIT) efficiently minimises total costs (either operational or capital). Should a non-network solution exist that efficiently minimises cost, then this option must be adopted. In most cases where the latter applies,

---

[18] Costs based on 2011 figures released as part of the 2011 Consumer Price Index Adjustments on 7 June 2011. Refer to Chapter 9 of the ENAC for more details on the Regulatory Test including the capital cost limits that trigger a ‘Reg Test.’

this typically involves deferring the capacity augmentation project from 1 to 5 years through the adoption of DM. The NPC of the deferred project together with the cost of DM is less costly than the immediate implementation of the supply side project. A summary of DM techniques is provided in Appendix F.

5.3. Other Enabling and Emerging Technologies

A number of technologies exist elsewhere in the world that are not currently employed by Western Power. These technologies may become increasingly important as various issues such as space constraints, HILP protection, river crossings and improved network performance become more prominent.

Space constraints are fast becoming an issue in the CBD Load Area as available land is increasingly difficult to find. Western Power is in an admirable position as several plots of land are currently owned and could be suitable for conversion into new zone substations, if required. Some of the sites, however, may have certain restrictions on design aspects such as building height. Technologies exist that allow a substation to be much more compact in its design than in the past through the use of gas insulated equipment or gas-cooled, oil-free transformers. GIS substations are considerably smaller in physical size than AIS substations of the same capacity, in some instances more than 50% smaller. Additionally, gas insulated switchboards are virtually fault-free and present a very high reliability solution, potentially obviating the need to have transfer capacity to back up an entire substation in the Perth CBD Boundary. Such a choice of technology could prove beneficial to Western Power and should be considered for new zone substation design in the CBD Load Area where appropriate. However, applying this technology to the Perth CBD Boundary may not have a large impact as all existing Perth CBD Boundary substations are compact in design. A potential savings in space may result in the total building dimensions that house the substation, though this would be dependent on the final design. Figure 22 shows the use of gas insulated transformers.

- **Figure 22 Gas Insulated Transformers**

Technologies focused on reducing the effects of a HILP event may also prove beneficial. A HILP event could include, for example, a fire on a portion of an existing substation that propagates and destroys more assets than the initial failure. For such a scenario, fire walls between transformers and switchboards to create separation, sealed wall penetrations, fire doors and fire-survival control and protection cables could serve to limit the spread of damage and extinguish the fire. The use of oxygen scavenging devices which activate automatically in cable boxes to extinguish fires in these areas, thereby preventing the de-energization of the whole substations to fight localized fires is another option. Also, the use of fire suppression equipment within the substation such as auto-discharging Halon gas (with suitable breathing apparatus for personnel, access alarms and push-latch doors for the safe escape of personnel who may inadvertently be present in the substations when the gas is discharged) could be employed. It should be noted the existing substations in the Perth CBD Boundary already employ some of these technologies. Incorporation of other suitable technologies may, however, serve to further prevent disasters at the sites.

Should vandalism become a problem in the CBD Load Area substations, existing technologies such as electric fences, video surveillance, quick response teams and random security patrols could serve to reduce such instances.

Additional technologies that could usefully be deployed to enhance electrical area supplies across the Western Power Network, including the CBD Load Area, include:

- Phase-shifting transformers – to provide control of power flows, particularly under contingency conditions
- FACTS devices – dynamic reactive compensation assets (STATCOM, SVC, Energy Storage, etc)
- Fault level mitigation devices – superconducting fault current limiters to enable substation busbars to be operated closed thereby enhancing security of supplies
- Combined usage buildings – many cities worldwide have substations contained within multi-use buildings, including in building basements and within car parks as a means by which to use available land efficiently. However, safety can often be a concern, adding to the costs associated with the construction of the building.

5.3.1. Self Healing Distribution Networks

A self healing distribution network is a network or sub network that has the ability to sense, diagnose, isolate and at least temporarily correct a fault or performance condition without human intervention [25]. A relatively new development in the Smart Grid area, these networks are able to increase reliability through faster response times and less instances of human error. As these networks include a significant amount of automation, a number of factors can be considered at once that may otherwise be missed by a human operator.

Benefits of such networks include faster restoration time for faults as well as the ability to move load to avoid unexpected peaks, manage voltage issues and increase security in some areas for short periods of time. It should be noted a self healing network does not eliminate the risk of a fault on the network.

This is not to say there are no risks associated with self healing networks. Concern has been expressed by some network operators as to the risk benefit tradeoff. Reclosing of circuits in overhead networks has always been seen as a risky business; however consumers have expectations that faults will be restored as quickly as possible [25].

Though a relatively new concept, self healing networks have the capability of providing a much more secure network.

5.3.2. Subsea Cabling

The CBD Load Area is bordered by the Swan River to the South and East. Existing connections over the river have been achieved by utilising road and rail bridges and installing cables within these structures. It is likely that future connections to the load area will be required and the availability and practicality of installing within existing road and rail bridges may be limited. Under these conditions subsea cabling could be utilised to allow connections to be made over the Swan River.

State of the Art

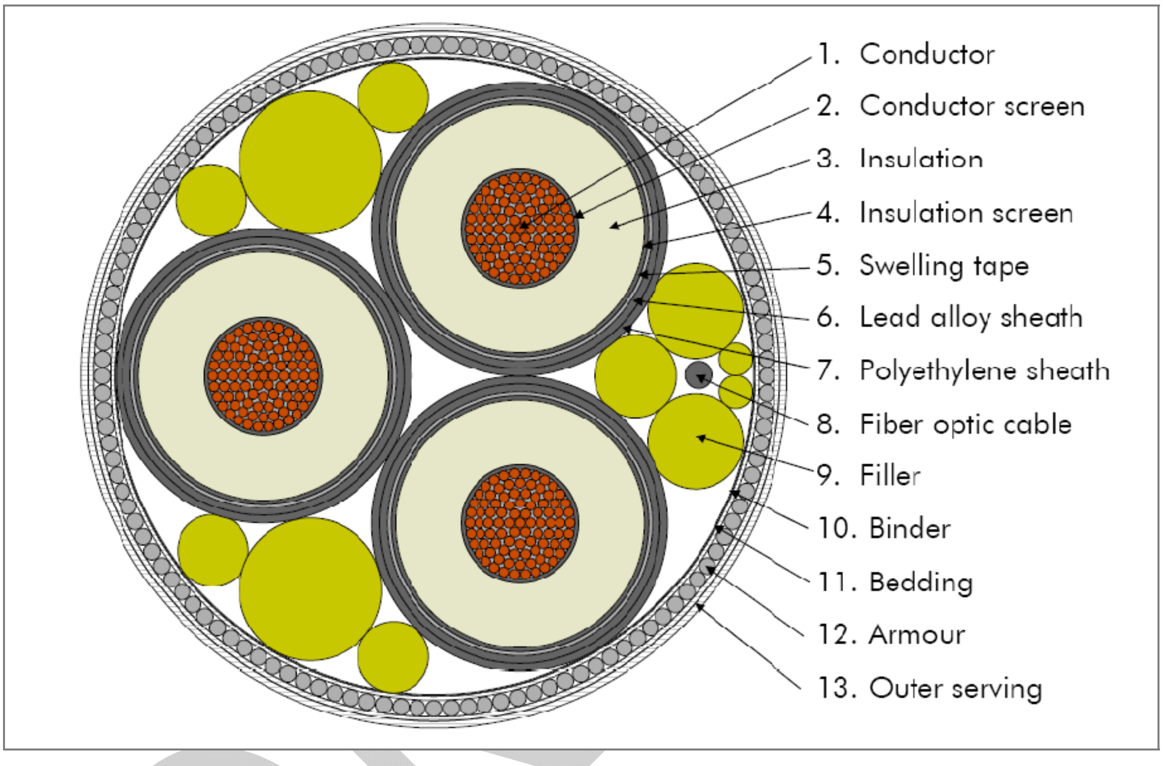
Cable technologies have continued to advance significantly over the past 20 years to accommodate the rising difficulty in overhead line consenting onshore and a growing subsea market to support offshore renewable developments and interconnectors. The equipment discussed within this section will relate directly to HVAC cabling due to the connection distances involved, however significant advancements in HVDC cabling and technology have also been seen, particularly within the last 10 years to support long distance, low loss transmission of power.

HVAC subsea cabling can be supplied in a 3-core package or as three single cores. The current state of the art for 3-core cables is 245 kV, whilst for single core subsea cabling 420 kV is available. The primary restriction for 3-core cable is not the incapability of the technology but the installation and handling limitations associated with such large cables. For subsea cabling 3-core cable is typically preferred so as to minimise installation costs. Losses are also higher in a single core formation and the environmental impact of electromagnetic fields (which is significantly reduced in a 3-core format) on marine life is under research and currently inconclusive [26].

Figure 23 illustrates the typical design of a 3-core subsea cable. The insulation material is typically XLPE to minimise maintenance and potential environmental impact in comparison with oil filled cables or gas insulated ducts. The electrical reliability of XLPE is also seen to be greater than these comparative technologies. Steel wire armour is employed in conjunction with the solid dielectric to provide improved strength in comparison with lead sheathed paper cables which is significant considering the subsea cables undergo particularly onerous stresses during transport, laying and operation. Copper rather than aluminium conductors are typically employed in subsea cables to provide a higher rating for a given cross-sectional area (approximately 20%), thus reducing the overall weight of the cable which directly impacts on the installation costs.

The current maximum capacity of a 3-core 132 kV subsea cable under typical installation conditions is 190 MVA based on the maximum conductor cross-sectional area of 1000 mm^2. Such a cable would have typical weight of 96 kg/m, a diameter of 221 mm and a minimum bending radius of 3.5 m. Conversely the current maximum capacity of a 3-core 245 kV (220 kV) cable is some 314 MVA based on the equivalent maximum cross-sectional area.

Capital costs for the aforementioned cables would be in the region of $1,000/m for 132 kV cable and $,1400/m for 245 kV cable. The cost of the cables is highly dependent upon the price of oil and metals at the time of order, whilst factoring an increasing competition between suppliers in this market. A procurement lead time of some 1 to 2 years would be expected.



- **Figure 23 245 kV HVAC 3-core Submarine Cable**

Reliability

CIGRE provides the most comprehensive source of service experiences for underground and subsea cables, primarily from European respondents within brochure 379 [27]. Furthermore, CIGRE brochure 398 provides details at to the causes of failures, particularly those attributable to third parties, of both underground and submarine cables [28].

Analysis of subsea cable failures provided in these documents indicate a failure rate attributable to third party damage of 0.000705 failures/year/circuit km and no internal electrical failures for XLPE subsea cables. This illustrates the extent to which subsea cables are at risk from external impacts such as shipping as well as the intrinsic reliability demonstrated by this form of cable. In reality, it can be assumed that there is a probability of internal failure, even if this has not been seen within this sample. Review of the underground cable installation internal failure rates provides a value of 0.00027 failures/year/circuit km, approximately a seventh of the external failures reported. It should be noted that the majority of these internal failures on underground cables are attributable to accessories such as joints.

The expected lifetime of HVAC subsea cables is some 40 years.

The CIGRE brochures also indicate repair times for XLPE subsea cables. It is seen that all repairs in the survey were completed within 2 months with half being repaired within a month. The variation in repair time is likely to be influenced by the availability of cable repair equipment, a suitable repair vessel, spare cable weather conditions and distance offshore.

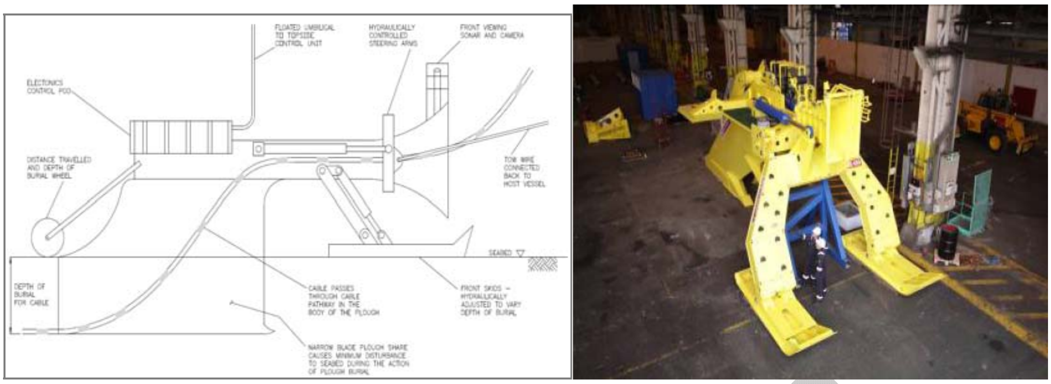
Installation Techniques

It has been seen that the vast majority of subsea cable failures are attributable to third party impacts, about two and a half times more than internal failures. As such, many subsea cables are buried below the seabed to protect against small anchor impacts, fishing nets, dredging activities and other third party marine activities. Typically this is to a depth of 1m or greater, although the project specific aspects need to be carefully considered such as the magnitude and type of shipping, dredging activities and depth to calculate the risk associated and an appropriate burial depth. CIGRE propose a method for determining acceptable protection levels for submarine power cables [28].

Subsea cables can be installed with a variety of techniques to provide the burial depth which allows greater protection of the cable from third party impacts. This can include:

- Jetting
- Ploughing
- Rock Ripping
- Vertical Injection

Jetting fluidises the seabed by utilising high pressure water jets. With the seabed in a semi-solid state, the cable is pushed to its burial depth. Ploughing is shown in Figure 24 and is similar to ploughing seen in agricultural practices onshore. The plough cuts the seabed to the required depth and installs the cable in the trench created. The seabed will naturally cover the trench through subsea movements of the dispersed sediment. Typically jetting is utilised where depths of up to 3 m are required, whilst ploughing is generally restricted to a depth of 1.5-2 m. Rock ripping is an extension of ploughing, utilised to install cable through hard seabed conditions or rocky outcrops along the route. Vertical injection is an extension of jetting, using a similar technique but capable of burial depths of up to 10 m.



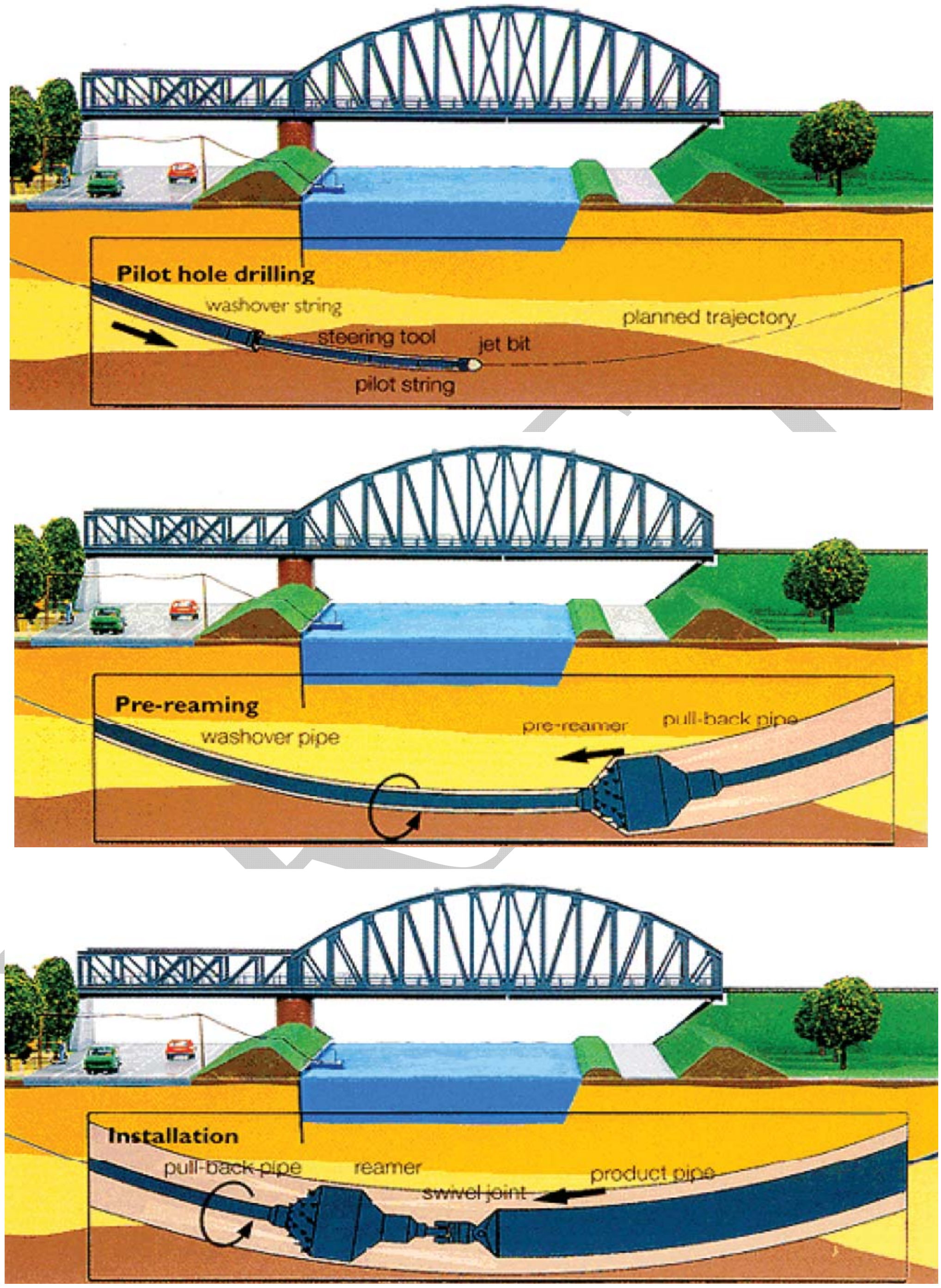
- **Figure 24 Subsea Cable Plough**

The depth and burial method chosen depends on the seabed conditions (e.g. soft sand, clay, chalk) but in some circumstances burial may prove too challenging such as in solid rock. In such cases other cable protection systems can be employed such as the use of rock placement or concrete mattresses.

- **Figure 25 Concrete Mattress and Rock Placement**

Horizontal Directional Drilling (HDD)

Considering the likely application of subsea cabling is to traverse the Swan River, it may be possible to utilise a HDD technique over directly burying a cable within the seabed. HDD was first developed in the 1970s using drilling technology from the oil and gas industry and revolutionised the crossing of large rivers. The HDD procedure is illustrated in detail within Figure 26 and effectively installs a duct within which the power cable can be pulled.



- **Figure 26 Typical Directional Drilling Procedure**

The directional drilling procedure removes the requirement for any subsea works with the drilling being carried out from land on either side of the crossing. This minimises the impact on the marine environment substantially and allows more standard onshore cables to be installed within the duct.

De-rating of the cable requires careful consideration as the duct is typically installed some 10m below the seabed, with fluids such as bentonite providing improved thermal characteristics to minimise this impact.

At present, HDD rigs are capable of crossing lengths over 2 km although greater distances can be achieved using an intercept method whereby a drill from the both sides of the crossing meet in the middle. The primary restriction involved is the pulling of the cable through the duct due to the forces involved over such a distance. Project specific analysis would be required to be carried out to assess the feasibility of pulling the cable over great distances.

A typical HDD compound will require some 30 m x 30 m on both sides of the crossing for the entry and exit of the drill.

6. Summary & Recommendations

This report has focussed on the current Western Power planning philosophy to provide advice on transmission and distribution network expansion for the CBD Load Area. A comparison has been made of the Perth CBD Boundary to other major cities giving consideration to reliability standards, transmission and distribution network architectures and distribution network installation techniques as well as an assessment of emerging and enabling technologies that may be applied to the network. This report serves to guide planning decisions for the development of long term strategies for the transmission system supplying and within the CBD Load Area.

6.1. Reliability

After a review of the existing reliability criteria utilised by Western Power and a comparison made to other similar utilities, the following summarises the findings of this report:

- The existing Perth CBD Boundary was developed in recognition of the economic importance of loads located in this small area to the conduct of business throughout the state.
- Historically there have been few incidents and limited customer complaints based on the reliability standards that currently apply for the Perth CBD Boundary.
- By comparison to other major cities in Australia and worldwide, an allowable interruption of supply for 30 seconds at the transmission level under a single contingency event is quite lenient.
- Due to the present Western Power standard transformer design, the 11 kV busbars are not able to be operated solid for fault reasons, resulting in some switching time to restore load during a contingency.
- The existing N-2 Perth CBD Boundary transmission criterion, with an allowable interruption to supply for two hours for an N-2 contingency, is comparable to many other standard planning practices.
- At a distribution level, some Australian CBDs afford a higher level of reliability than the existing network in Perth CBD Boundary, though not without significant network investment.
- Whilst Western Power no longer plans for HILP events as part of its current Transmission Planning Criteria the current planning practices employed to achieve N-2 have resulted in a DTC network capable of providing full back up to the substations within the Perth CBD Boundary.

Further analysis in this area has yielded a number of recommendations for the existing reliability criteria within the CBD Load Area. The recommendations are as follows:

1) It is not recommended to expand the Perth CBD Boundary beyond that defined in the Technical Rules in the short term. Western Power should continue to monitor the load density as new establishments are developed and periodically review the boundary.
2) Any new CBD Load Area substation developments outside the present Perth CBD Boundary should be planned initially for bumpless N-1 with a view to ultimately providing for N-2.

3) Conversion of the existing Perth CBD Boundary substations from the current N-1 criterion to a bumpless or reduced interruption time system should be undertaken where this can be achieved at a marginal additional cost to other works.
4) The additional investment required to support a HILP event within the Perth CBD Boundary to above what is required to maintain N-2 security should be calculated and the positive net benefit assessed using probabilistic methods. Alternatively, the installation of fire fighting systems to limit fire damage, CCTV surveillance systems and other such measures are recommended to reduce the risk and potential outage time.
5) It is recommended to continue to install some DTC between substations sites, where opportunities exist, to facilitate rotational load shedding techniques, if absolutely necessary.

It is recognised the existing network has developed under the planning philosophies to date. Given this, a review of the existing assets provides clear guidance on the benefits and shortcomings of existing philosophies. To this end, a review of the existing distribution and transmission network architecture has been undertaken.

6.2. Distribution Network Architecutre

The existing Western Power distribution network within the CBD Load Area was assessed against known limitations. A greenfield approach was then taken to recommend improvements, where possible, for the continued development of the network. The following summarises the findings of this report:

- A number of limitations exist on the distribution network within the Perth CBD Boundary including existing cable congestion at substation exit points and limitations on new cable routes within the Perth CBD Boundary. If the cable congestion issues are not addressed in the near term, the continued use of 11 kV to connect new load within the Perth CBD Boundary will not be economically appropriate moving forward.
- The existing network already has a notable percentage of equipment rated for 22 kV operation, currently operated at 11 kV.
- Distribution feeders within the Perth CBD Boundary are restricted to 50% utilisation to ensure N-2 support; this has resulted in a large number of cables required to supply the load demand.
- The use of some DTC was found to be beneficial in providing support to neighbouring zone substations during contingencies, but did not cater for a double circuit contingency on the two incoming feeders to the substation.
- Ensuring N-2 compliance exclusively via DTC would further exacerbate the cable congestion issues presently seen on the network.

Analysis of various options to address the limitations was performed on a greenfield basis initially. Idealised models were created which were then used to guide the development of more targeted network strategies for the actual network. The following recommendations are made:

6) To utilise the maximum amount of transformer capacity within the Perth CBD Boundary, the distribution planning practice of limiting cable utilisation to 50% should be reviewed with a view to increasing utilisation in the short term to facilitate further load connections.
7) Thermal rating calculations should be undertaken to appropriately rate equipment, ensure maximum utilisation of existing assets and reduce the need for the installation of additional feeders in an already congested network.
8) A holistic assessment of distribution operating voltages demonstrates migrating substations within the CBD Load Area to 22 kV as attractive, unless otherwise required to retain 11 kV. Generic analysis also demonstrates a staged migration on an as-required basis to be preferred as savings in the order of $18M may be realised. This would require 22 kV equipment to be installed, but initially operated at 11 kV, until such time as the CBD Load Area is fully converted. It is recommended to further investigate this option to better understand the impact on cost benefit and cable congestion.
9) Generic analysis of the distribution network supporting N-2 compliance demonstrates the benefits in installing a combination of some DTC and a transmission interconnection. It is recommended to investigate this further for application to substations within the Perth CBD Boundary.

6.3. Transmission Network Architecture

A review has been conducted of the existing Western Power transmission system in the vicinity of the CBD Load Area. From this, a number of observations can be made:

- The existing transmission system supplying the CBD Load Area is a highly meshed 132 kV network, emanating from a number of external 330 kV bulk supply points. The current architecture results in numerous interdependencies between northern and southern networks supplying the CBD Load Area, and is sensitive to generation dispatch conditions. This leads to considerable challenges to plan and operate the network.
- The existing 66 kV network infrastructure in the CBD Load Area has reached the end of its service life.
- The cost premium for moving to 132 kV is now considered negligible.
- There is little need for a higher voltage than 132 kV at the present time or within the short to medium term.

Further analysis was undertaken on a brownfield basis to provide recommendations for the continued development of the transmission network:

10) Analysis shows a number of benefits in removing the 66 kV assets in the CBD Load Area in favour of 132 kV assets. It is recommended to replace these assets are at the end of their economic life with supplies rationalised into a smaller number of larger 132 kV substation sites.
11) Migrating to a transmission system voltage higher than 132 kV (330 kV) should be considered once the CBD Load Area demand reaches circa 700-800 MW, anticipated to be around 2030 to

2035. This timeframe will also present an opportunity to rationalise the CBD Load Area supplies.

12) Suitable locations for potential 330 kV terminal substations in the vicinity of the CBD Load Area should be identified in the short term.
13) The potential to construct higher capacity new 132 kV transmission lines in whole or part to 330 kV specification to facilitate future upgrades should also be considered.

6.4. Emerging and Enabling Technologies

Finally, emerging and enabling technologies were assessed for implementation within the CBD Load Area. The following summarises the findings of this report:

- A review of installing a pit and duct system versus a cable tunnel concluded that a pit and duct system would be more economically attractive, though limited by the number of cables that could be installed.
- Installation of a cable tunnel would allow for a combined transmission and distribution system and potentially accommodate other services.
- DM techniques were presented and reviewed as part of this study recognising they are unlikely to prove a substitute for traditional network capacity and asset investment. These techniques can, however, improve the spend curve by delaying investment for a period of time.
- Self healing distribution networks were briefly discussed including the advantages that implementation of such a network may bring to reliability or performance.
- Due to the geographical location of the CBD Load Area, future connections that require crossing the Swan River may require the use of alternative techniques such as subsea cabling or HDD techniques.

Thorough review of documentation provided along with further analysis yields the following recommendations:

14) It is recommended to further investigate project specific issues alongside longer term strategic area plans to determine the extent to which pit and duct could be employed across the Perth CBD Boundary and to identify areas where a cable tunnel may be more efficient.
15) The use of GIS equipment should be considered for any future zone substations within the CBD Load Area.

7. References

[1] Reference 1

[2] Reference 2

[3] Reference 3

[4] Reference 4

[5] Reference 5

[6] Reference 6

[7] Reference 7

[8] Reference 8

[9] Reference 9

[10] Reference 10

[11] Reference 11

[12] Reference 12

[13] Reference 13

[14] Reference 14

[15] Reference 15

[16] Reference 16

[17] Reference 17

[18] Reference 18

[19] Reference 19

[20] Reference 20

[21] Reference 21

[22] Reference 22

[23] Reference 23

[24] Reference 24

[25] Reference 25

[26] Reference 26

[27] Reference 27

[28] Reference 28

Appendix A Cable Issues at Existing Sites

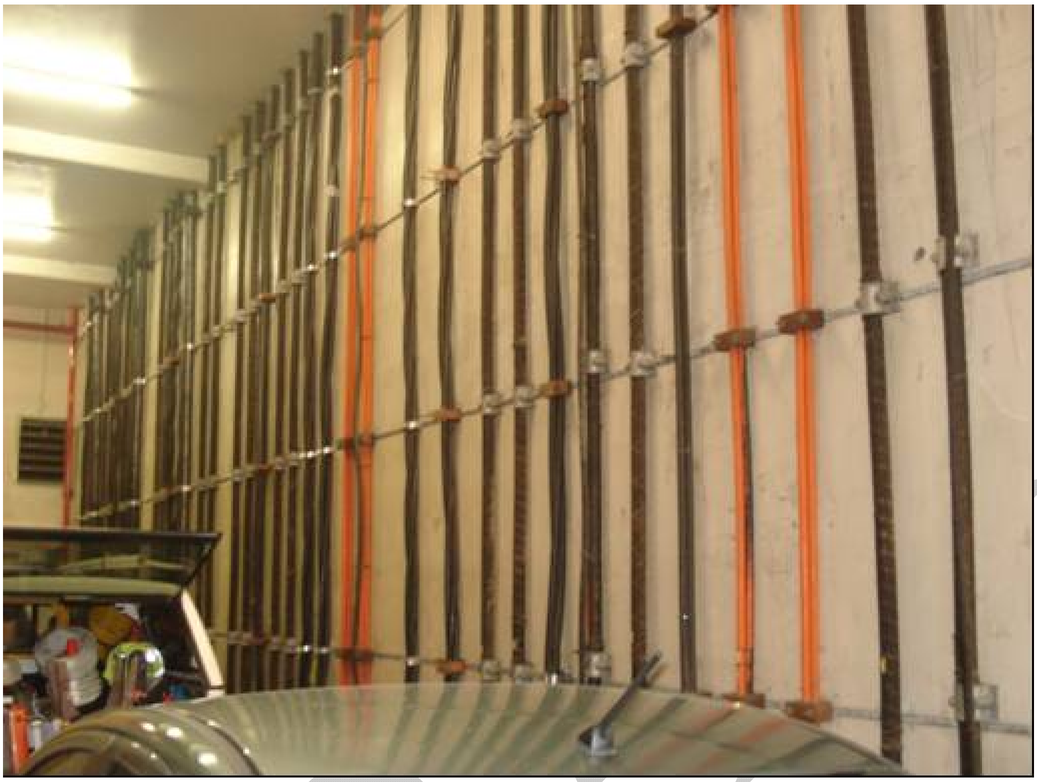


Figure 27 Existing Cable Installation Congestion at a CBD Zone Substation

Figure 28 Existing Cable Congestion

Figure 29 Existing Installed Paper Insulated Cables

■ **Figure 30 Existing Cable Tunnel Under the CBD**

Appendix B Load Growth Table

Substation	Configuration	Firm Capacity (MVA)	Power Factor	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
East Perth 132 and 66 kV	132/66/22 kV, 2x100/75/50 MVA	450.0	0.89	324.4	341.5	353.8	363.2	371.7	381.6	389.8	400.7	411.1	419.6	428.2	436.7	445.3	453.8	462.3	470.5	478.6	486.7	494.8	502.9	511.0	519.1	527.2	535.3	543.4	551.5
Hay Street 132 kV	132/11/11 kV, 3 x 71 MVA	142.0	0.88	83.2	86.7	87.6	89.8	90.7	91.6	92.6	93.5	94.4	95.4	96.3	97.3	98.2	99.2	100.1	101.1	102.1	103.0	104.0	105.0	106.0	106.9	107.9	108.9	109.9	110.9
Cook Street	132/11/11 kV, 2 x 81 MVA	81.0	0.89	78.4	80.4	81.9	83.3	84.6	87.2	88.4	90.0	91.5	93.1	94.6	96.1	97.5	98.9	100.3	101.3	102.3	103.3	104.2	105.2	106.1	107.0	107.9	108.8	109.7	110.5
North Perth	132/11/11 kV, 3 x 34 MVA	55.0	0.90	52.9	55.4	57.5	59.6	61.7	63.8	66.0	68.1	70.2	72.4	74.5	76.7	78.8	81.0	83.2	85.4	87.5	89.7	91.9	94.1	96.2	98.4	100.6	102.8	105.0	107.2
Joel Terrace	132/11/11 kV, 1 x 76 MVA, 66/11 kV, 2X 24 MVA	48.0	0.92	35.5	37.2	38.6	40.1	41.6	43.1	44.6	46.1	47.6	49.2	50.7	52.2	53.8	55.3	56.8	58.4	59.9	61.5	63.0	64.6	66.1	67.7	69.2	70.8	72.3	73.9
Summer Street	132/22, 2 X 12 MVA	12.5	0.84	12.7	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3	14.3
Forrest Avenue	66/11 kV, 2 X 39 MVA	39.0	0.87	35.0	38.6	42.5	43.2	44.4	45.6	46.4	47.2	48.0	48.7	49.5	50.3	51.1	51.9	52.7	53.4	54.2	55.0	55.8	56.6	57.4	58.2	59.0	59.8	60.6	61.4
Wellington Street	66/11 kV, 2 X 29 MVA	29.0	0.92	26.7	29.0	31.5	32.9	34.5	36.0	37.6	41.6	45.0	46.6	48.3	49.9	51.6	53.2	54.9	56.6	58.2	59.9	61.6	63.2	64.9	66.6	68.3	70.0	71.7	73.3
Milligan Street	132/11/11 kV, 3 x 71 MVA	134.0	0.89	97.6	102.8	104.1	105.5	107.8	111.6	114.7	118.0	119.4	120.8	122.3	123.7	125.2	126.6	128.1	129.5	131.0	132.5	133.9	135.4	136.9	138.4	139.9	141.3	142.8	144.3

*- Indicates load exceeding 95% of firm (N-1) capacity
*- Indicates load exceeding 100% of firm (N-1) capacity

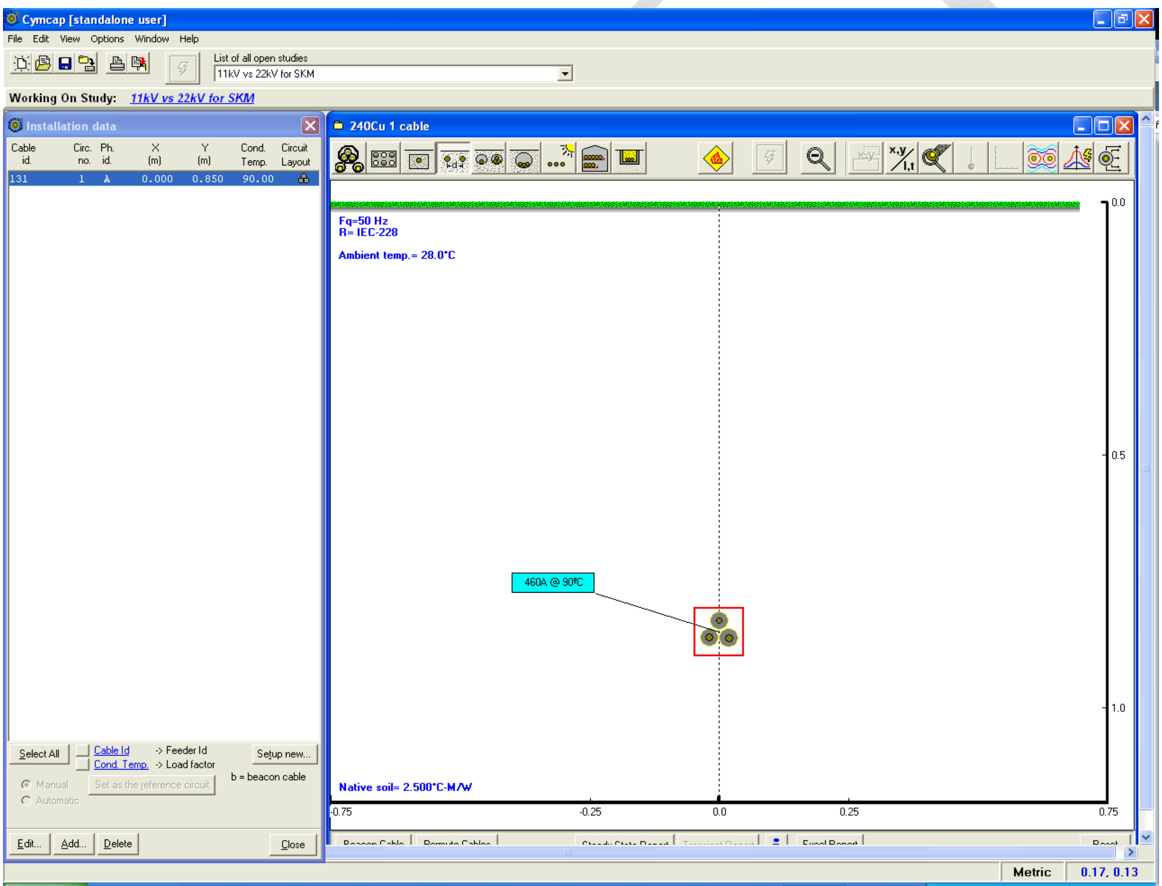
- **Figure 31 CBD Organic Load Growth Table**

This load growth table has been prepared using Western Power's forecasting tool Opal. The load forecast is based on 2011 forecasts for a 10% PoE. All load transfers have been removed and any site due to be decommissioned has been left in service to give an overall view of the organic or natural growth of load demand in the CBD Load Area. Individual site power factors have been assumed to be consistent over the 25 year period from 2011 –2036.

Appendix C Cable Rating Study

A simplified cable study was undertaken by Distribution Planning and Development to assess the thermal de-rating effects of multiple cables installed in close proximity. The study used CYMCAP software and focused on a typical distribution cable size of 240 mm^2 Cu, XLPE insulated at voltages of 22 and 11 kV. A base assumption was made that a 22 kV cable could carry twice as much current as an 11 kV cable, thereby requiring half as many cables to transport the same amount of power.

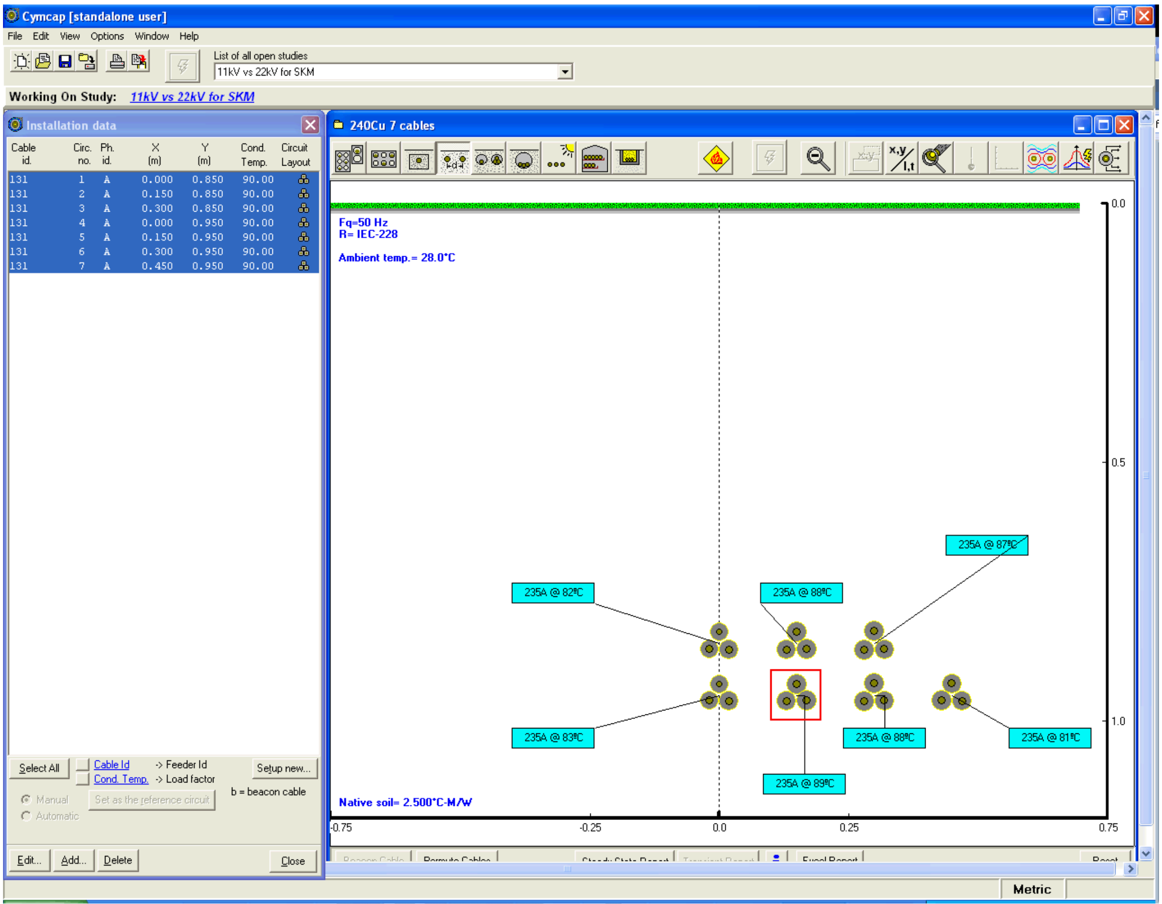
One 240 mm^2 CU, XLPE insulated cable was modelled assuming a soil thermal resistivity of 2.5, cable load factor of 0.6 and a constant loss factor of 0.2. Load was distributed evenly across the cables. It is important to note CYMCAP does not differentiate between cable voltages and instead supplies the maximum current that can be achieved on the cable under the installation conditions. This is shown in Figure 32.



■ **Figure 32 Initial Model of One Distribution Cable**

As indicated above, a single cable is capable of carrying 460 A at 90°C (8.76 MVA at 11 kV or 17.52 MVA at 22 kV).

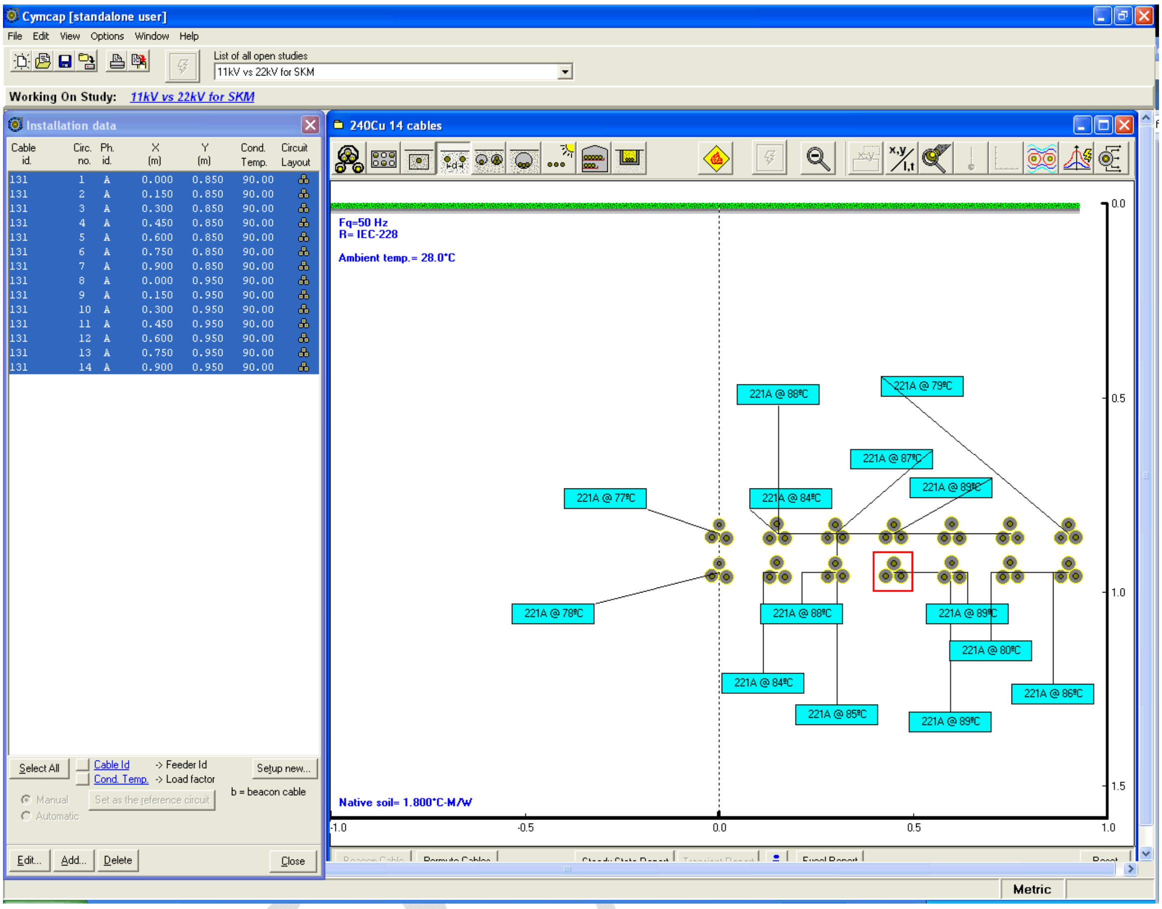
The model was then expanded to accommodate seven cables using the same modelling assumptions. This was used to reflect a 22 kV installation. The results are shown in Figure 33.



■ **Figure 33 Expanded Model of Seven Distribution Cables**

As can be seen above, seven cables installed in close proximity reduce the current carrying capability to 235 A, or approximately 8.95 MVA at 22 kV. This equates to an achievable power transport of approximately 61.6 MVA at 22 kV.

For comparison, based on the assumptions stated earlier, fourteen cables were modelled as it was anticipated that it would require twice as many cables at the lower voltage of 11 kV to achieve a similar power transfer. Using the same conditions as per the 22 kV study, it was found that each cable could carry only 221 A, or approximately 4.2 MVA per cable. This equates to a total power transfer of 59 MVA. Figure 34 shows the results of the study.



▪ **Figure 34 Expanded Model of Fourteen Distribution Cables**

Comparing the two voltages in more detail, it is now possible to state that the relationship between 22 kV and 11 kV is not direct. That is to say, the thermal de-rating experienced at 11 kV is much more severe than at 22 kV due to the larger number of cables. It can also be concluded that more than twice the number of 11 kV cables as 22 kV cables would be required to transport the same amount of power, though the studies indicate the relationship is not substantially greater than two 11 kV cables to one 22 kV cable.

Applied to the CBD Load Area, this indicates both a significant cost savings, as the number of 22 kV distribution cables required to support the anticipated load growth is slightly less than half the number of required 11 kV cables, and a significant reduction in cable congestion if the existing cables were to be replaced/uprated to the higher operating voltage.

Appendix D Distribution Network Architecture Options

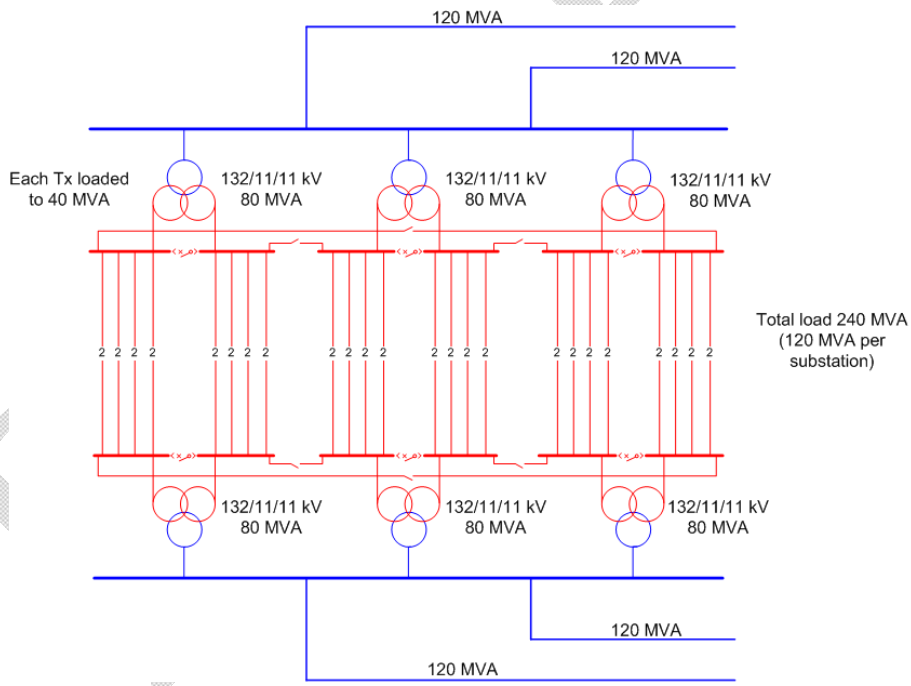
As stated in Section 1.2.2, a greenfield approach was taken to identify new distribution network architectures. The following subsections are the results of this exercise.

D.1 Two Substation Options with DTC

D.1.1 Option A – Current Perth CBD Boundary Architecture

The first option considers an arrangement similar to that found between Hay Street and Milligan Street. Currently, Hay Street and Milligan Street employ three 60 MVA (nameplate rating), 132/11/11 kV three winding transformers. The transformers each have specified LTERs ranging from 63 MVA to 76.2 MVA. A strong 11 kV interconnection exists between the two sites consisting of multiple feeder pairs. The cables are normally loaded to 50% of their current carrying capability in order to ensure N-1 compliance at the distribution level but also to allow the full load from Hay Street to be transferred to Milligan Street in the event of an N-2 contingency (and vice versa).

A similar concept was chosen for the first distribution architecture option, shown in Figure 35.



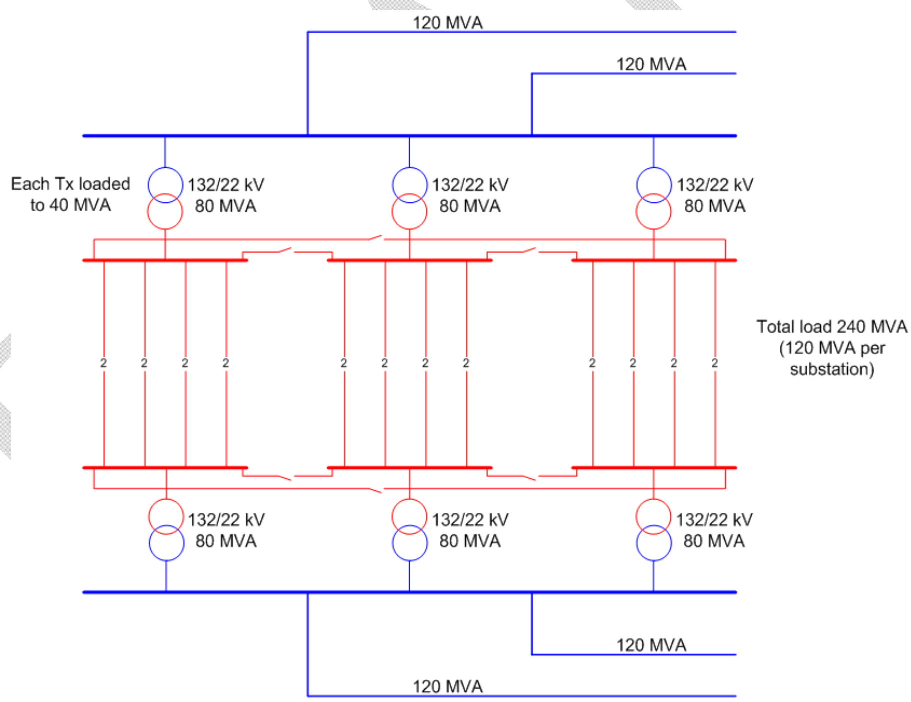
- Figure 35 Distribution Network Architecture Option A

This option calls for two new sites to be built, each capable of supporting 120 MVA under N-1 and N-2 for a total supportable load of 240 MVA, the estimated load growth within the Perth CBD Boundary over the next 25 years. This would require three 60 MVA, 132/11/11 kV three winding transformers, assumed to be capable of having LTERs of 80 MVA as shown in the figure, loaded to 50% capacity. Four 120 MVA, 132 kV incoming circuits would also be required, two to each site. The ratings of the incoming circuits have been selected to ensure full supply to the substation for an N-1 event on its paired transmission line, recognising 120 MVA as a minimum requirement. The two sites would be connected by 48 feeder pairs of 11 kV cables, each carrying 2.5 MVA. For loss of both 132 kV circuits supplying one of the sites, the other site would still be capable of supplying the full 240 MVA of load by utilising the DTC scheme.

This configuration has the advantage of being resilient to a HILP event. It lends itself to utilising a Pit and Duct system and provides a small degree of staging, as only two transformer pairs need be installed at each site initially with the third transformer pair being installed when the load materialises. Also, only one easement would be required for each site due to only two 132 kV circuits being installed at each substation. The disadvantages of this option include the use of three winding transformers, creating a risk of power imbalance in the LV windings if the LV busses are operated open and the underutilisation of assets as the transformers and circuits would only be loaded to 50% of their total capacity to ensure N-2 support. Additionally, two sites would need to be procured in order to build the substations.

D.1.2 Option B – Current Perth CBD Boundary Architecture with 22 kV Secondary

This option is similar to Option A in that it employs a similar arrange, albeit with three 60 MVA, 132/22 kV dual-wound transformers would be used instead of 132/11/11 kV transformers. Again, it is assumed the transformers would be able to achieve an LTER of 80 MVA. This distribution architecture option is shown in Figure 36.



- **Figure 36 Distribution Network Architecture Option B**

This option has some distinct advantages compared to Option A. The main advantage is the use of 22 kV at the distribution level as this would require half the number of distribution circuits to connect the two sites, in this case 24 circuits. Additionally, the dual-wound transformers would have a smaller footprint than the three winding transformers, saving space at the substation. As in

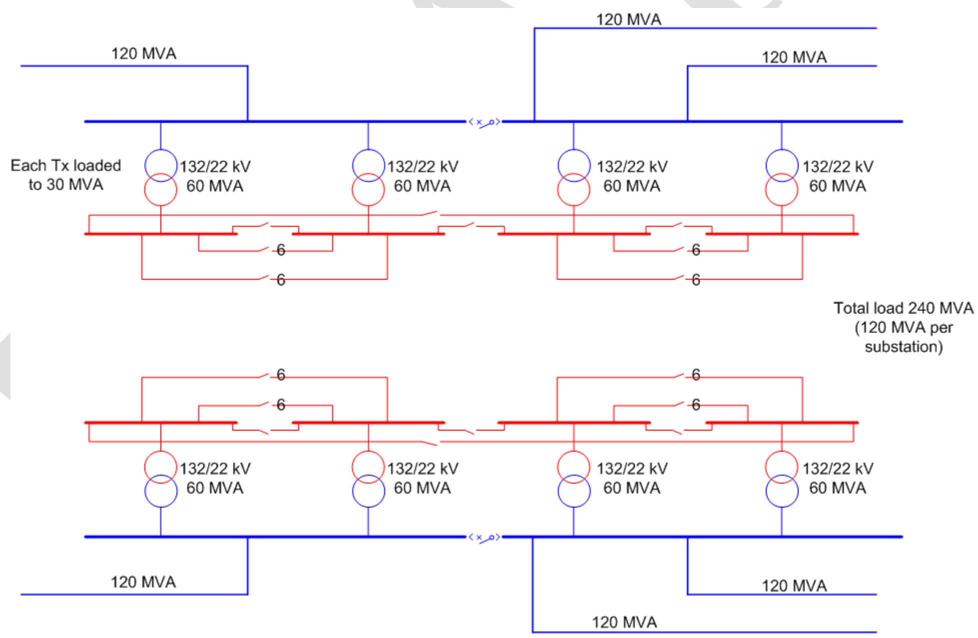
Option A this arrangement is resilient to a HILP event, so no loss of supply would occur as the load could be transferred to its paired substation.

The disadvantages are similar to Option A in that transformers and circuits would only utilise 50% of their rated capacity to ensure N-2 support and the ability to slightly stage the third transformer to meet growing load demand.

D.2 Two Substation Options without DTC

D.2.1 Option C – Melbourne CBD Architecture

The current distribution architecture supplying the Melbourne CBD utilises radial 11 kV feeders meeting at open points [10]. Groups of up to 11 feeders are backed up by a single unloaded feeder. To apply this arrangement to the Perth CBD and cater for 240 MVA of load demand, three 132 kV circuits would be required at each substation with four 60 MVA, 132/11/11 kV or 132/22 kV transformers. The difference in the architecture used for this option is that the 11 kV busbar supplying the ring main units would not be selectable as in the pure Melbourne model due to the assumed distances between zone substations in the Perth CBD Boundary. For the purposes of this exercise, it was decided that 22 kV would be used as the secondary voltage due to the benefits found in Option B (less feeders, application of dual-wound transformers, etc.). The distribution arrangement for this option is shown in Figure 37.



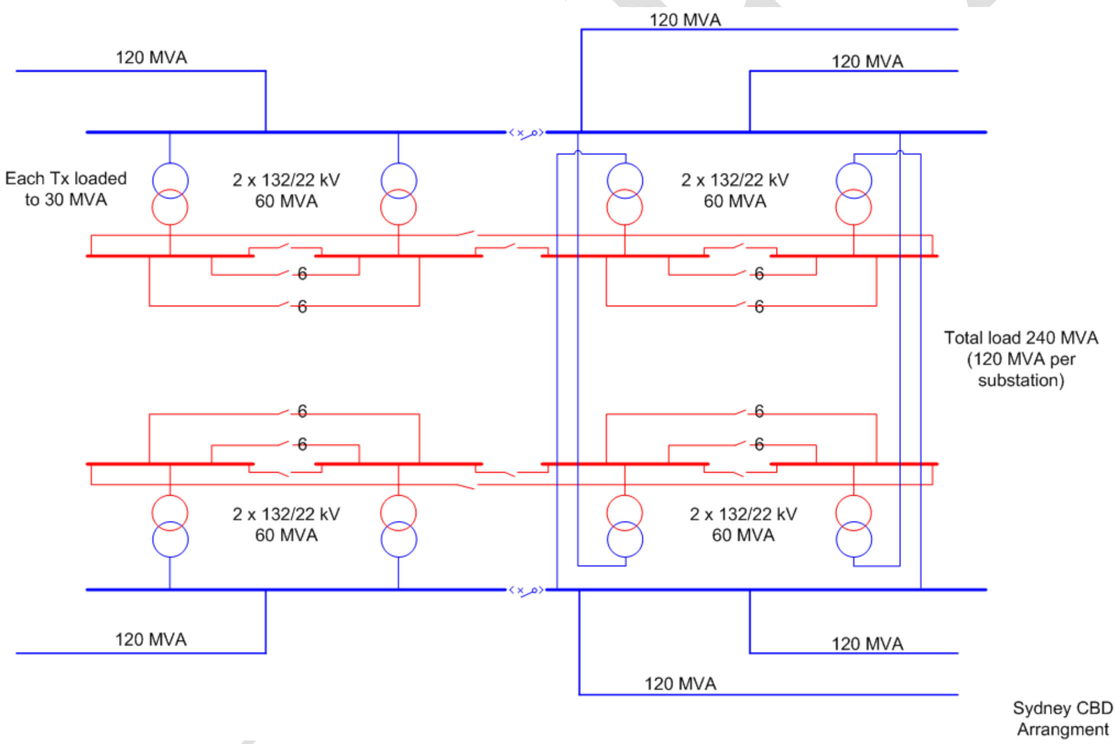
- **Figure 37 Distribution Network Architecture Option C**

This option would require the same number of 22 kV cables as Option B each feeder would need to loop back to the same switchboard and create a normally open point, limiting each side to 50%. Advantages of this option, however, include an easier to manage distribution system due to no DTC and flexibility of substation location because the sites are not interconnected. This would allow for the sites to be strategically located catering to the high density areas of load growth. Additionally, these sites could be staged fairly well as they could be built on an “as-needed” basis.

This is not to say that this architecture option is not without disadvantages. A major disadvantage for this option over Options A and B is the requirement for an additional easement for the third 132 kV transmission circuits. Obtaining corridors in a densely populated area could prove very challenging and expensive. Also, this option requires four transformers instead of three, albeit more standard sizes in line with typical Western Power procurement. Because of the additional transformer, each site would require more land adding to the overall cost. And neither site would be resilient to a HILP event, resulting in complete loss of supply from the affected substations.

D.2.2 Option C* – Sydney CBD Architecture

The Sydney CBD is based on the New York system [10]. Three transmission circuits connect to a 132 kV busbar supplying four step-down transformers. The difference from Option C is that one pair of transformers is supplied from a partner substation and one pair supplied locally. Figure 38 shows this architecture.

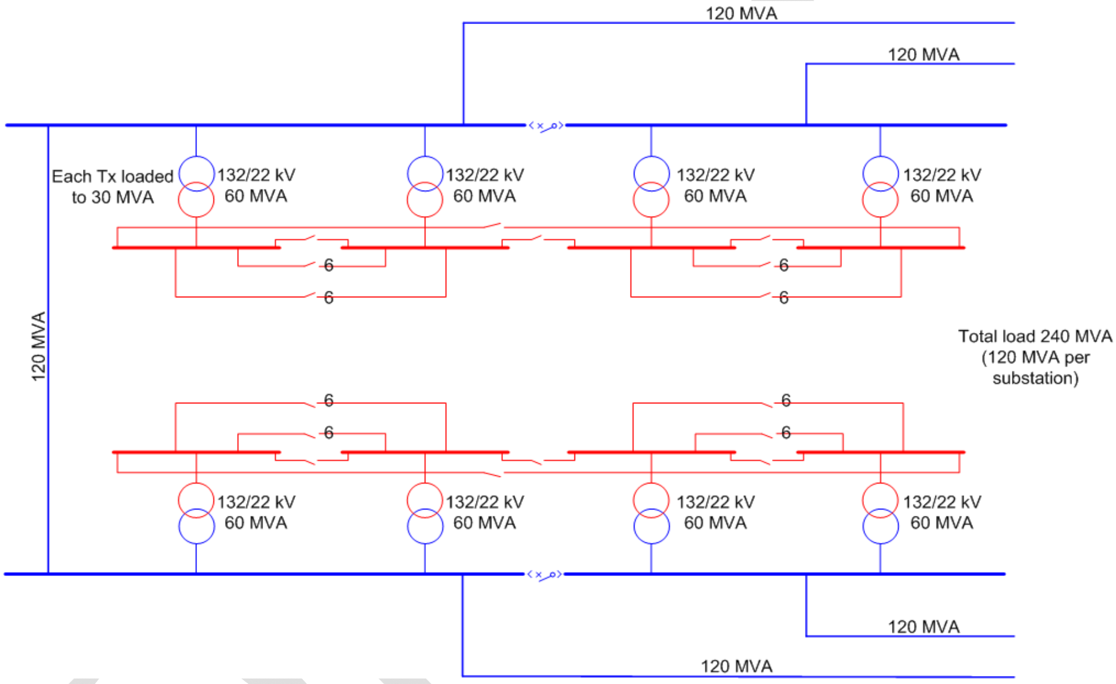


- **Figure 38 Distribution Network Architecture Option C***

This option is only a slight variation on Option C and has many of the same advantages/ disadvantages. Some additional advantages exist in terms of loss of the 132 kV busbar, however. For such an event, loss of the entire HV busbar would not cut supply to all customers in an area as only half the local load is supplied by the zone substation. In this situation, the bus couplers could be closed and maintain the 120 MVA supply at each site. Also, loss of all LV busbars at a site would result in loss of supply as no support is provided by the distribution network. This option does require additional lengths of 132 kV cable, however, making it more costly than Option C.

D.2.3 Option D – 132 kV Express Feeder

This option is a variation of Option C. It again uses the Melbourne transmission model as an example to supply the CBD boundary, but utilises less 132 kV circuits than Option C. Instead of three 132 kV circuits supplying each substation, two are installed with a 132 kV circuit connecting the two sites together. The difference from the Melbourne system is that each substation is supplied independently rather than from one site with 132 kV interconnections [10]. Figure 39 demonstrates the use of this architecture.



- **Figure 39 Distribution Network Architecture Option D**

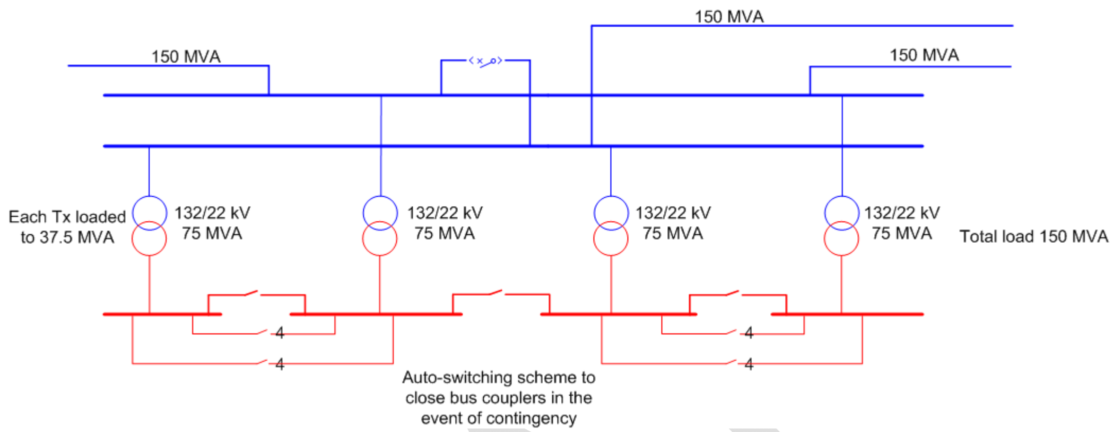
The advantages of this arrangement are similar to Option C in that no 11 kV interconnections exist between the two sites so the distribution system is less complex. This option requires less easements than Option C as there are less 132 kV circuits required and provides some degree of flexibility in staging the new substations. However, the two sites will need to be identified early as the 132 kV circuit corridor connecting the two sites will need to be available.

In order to maintain supply, the 132kV interconnection could be closed at each end to bring transfer all load from one site to another if 132 kV supply circuits were out of service. A disadvantage compared to the other options. Similar to Option C, this option is not resilient to a HILP event all load supplied by a single substation is able to be lost for some contingency events. This option also requires a large amount of real estate due to the requirement of four transformers at each site.

D.3 Single Substation Option

D.3.1 Option E – Single Substation

Option E examines the possibility of installing one single substation in the CBD Load Area to supply the expected 240 MVA load growth. This option calls for installing three 150 MVA, 132 kV circuits into a double busbar substation with four 75 MVA, 132/22 kV transformers. Figure 40 shows this architecture.



- **Figure 40 Distribution Network Architecture Option E**

As can be seen, this option is not able to supply a total load of 240 MVA. This is due to the use of smaller transformer sizes as per Western Power procurement. The four transformers would be capable of supplying 300 MVA under an intact system, 225 MVA for an N-1 contingency event and 150 MVA for an N-2 contingency event. The forecasted new load growth in the CBD Load Area is expected to exceed 150 MVA by 2026, meaning that the installation of one larger substation would defer the need for further invest by 15 years. However, after this another similar substation would be required to support the load growth.

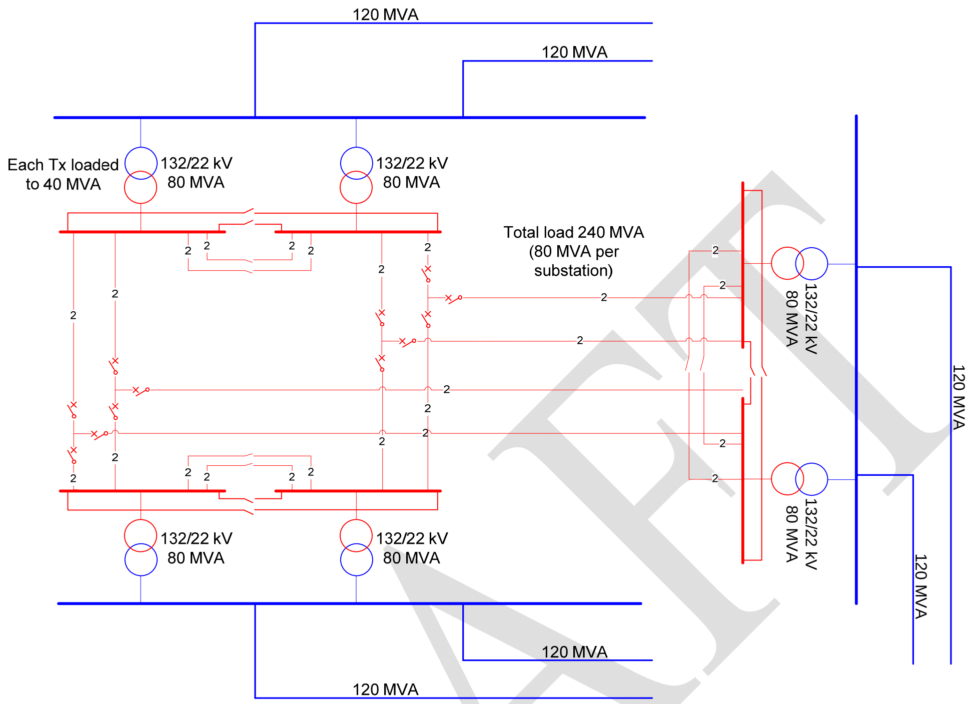
In addition to deferring investment, this option would require an auto-switching scheme to close the bus couplers in the event of an N-1 contingency. This option can be staged as necessary with three transformers installed until 2018, after which the forecasted load exceeds 75 MVA and the fourth transformer would become necessary.

A disadvantage of this option is the requirement for additional easements for the third 132 kV circuit. Also, installing four transformers at one site would require a large footprint which could prove expensive. Utilisation of assets would also be quite low as an N-2 contingency event where two transmission circuits are lost would only use 50% of the available transformer capacity.

D.4 Three Substation Options

D.4.1 Option F – Three Substations

This option examines the possibility of three substations rather than one or two in the CBD Load Area to support the forecasted load growth. In order to accommodate 240 MVA, three substations would need to be installed with two 120 MVA, 132 kV circuits and two 80 MVA, 132/22 kV transformers each (six circuits and six transformers in total). The substations would be interconnected at 22 kV providing a large distribution transfer capability between sites. Figure 41 shows this architecture.



■ **Figure 41 Distribution Network Architecture Option F**

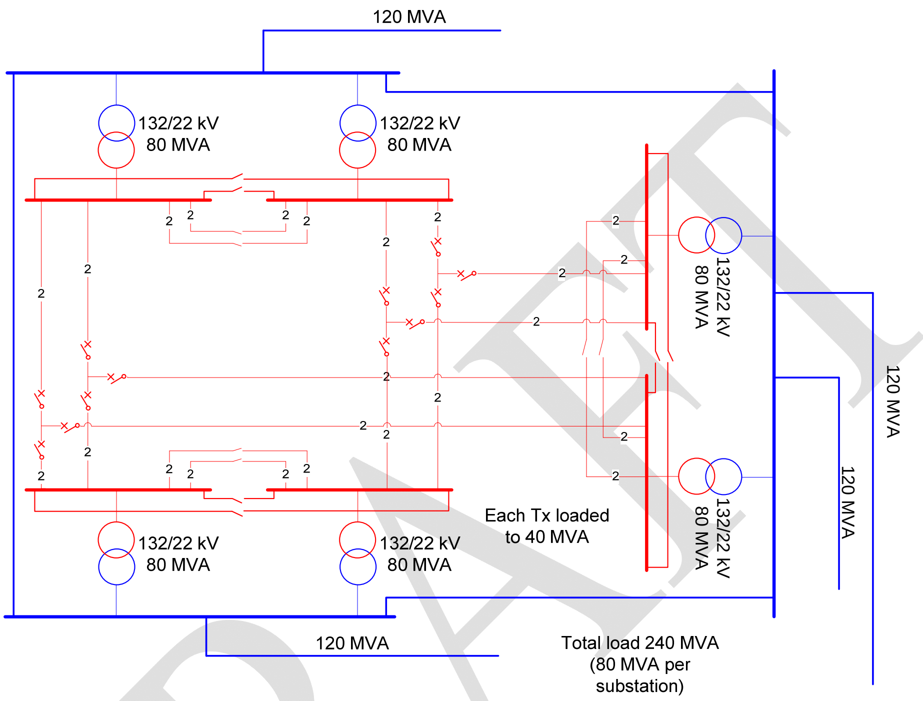
In this scenario, the DTC would be better utilised than in Options A and B as 67% of the total capacity of the cables would be used instead of only 50%. The interconnections would be operated by loading any two legs of the tee and leaving the third leg open. In the event of a contingency, this leg could be closed to supply the load from another substation.

This option provides a large amount of 132 kV capacity into the Perth CBD Boundary. It also enables supply of new bulk loads directly at 22 kV. Similar to Options A and B, this option is HILP resilient as the DTC could be used in the event of loss of a whole substation. This option also has the benefit of smaller substations as only two transformers would be installed at any one site thereby reducing the footprint and real estate costs. Additionally, the third substation could be installed on an “as-needed” basis as the load materialises.

However, real estate is also a disadvantage as three separate sites would need to be procured. Additional lengths of 22 kV cable would also be required to interconnect the sites, and a complex control system would be required to ensure appropriate use of the teed arrangement associated with the distribution interconnections. The number of 132 kV circuits also could present a problem as several easements would be required for this option.

D.4.2 Option F* – Three Substations with Express Feeders

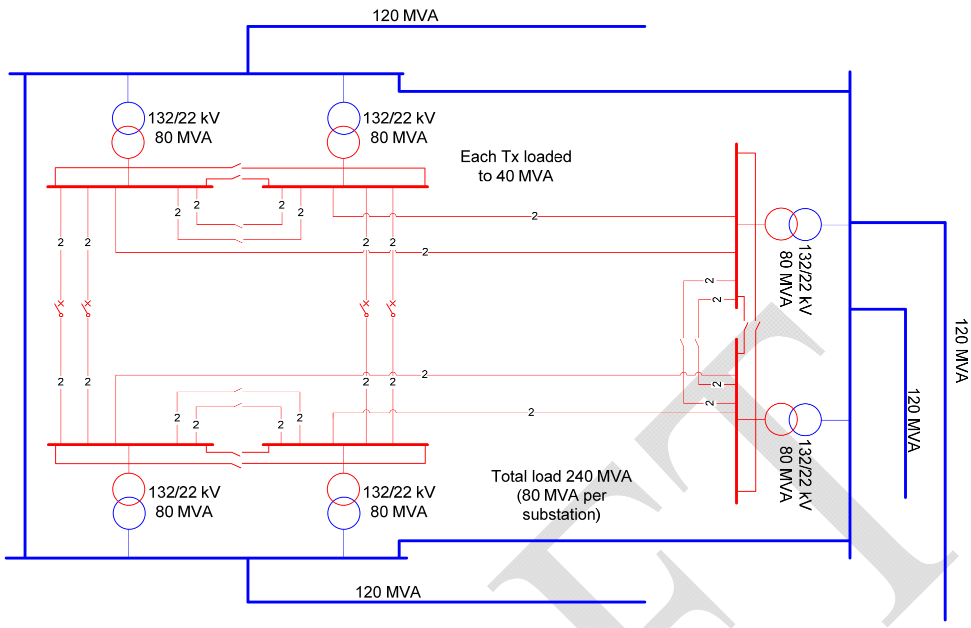
This option is similar to Option F except that only four 132 kV circuits supply the substations and a 132 kV ring is built between sites. This has the advantage of potentially reducing the total length of 132 kV circuits required. The rest of the advantages and disadvantages are similar to Option F. The figure below shows this architecture option.



- Figure 42 Distribution Network Architecture Option F*

D.4.3 Option G – Three Substations no DTC

Option G is a slight variation to Option F*. Instead of utilising a complex DTC system, the third circuit would cut into the first two sites and directly connect at 22 kV. This reduces the complexity of the distribution control system as the switching arrangement under a contingency is not as complicated. However, the feeder cables could be loaded to only 50% to ensure N-1 reliability. Figure 43 shows the architecture for this option.

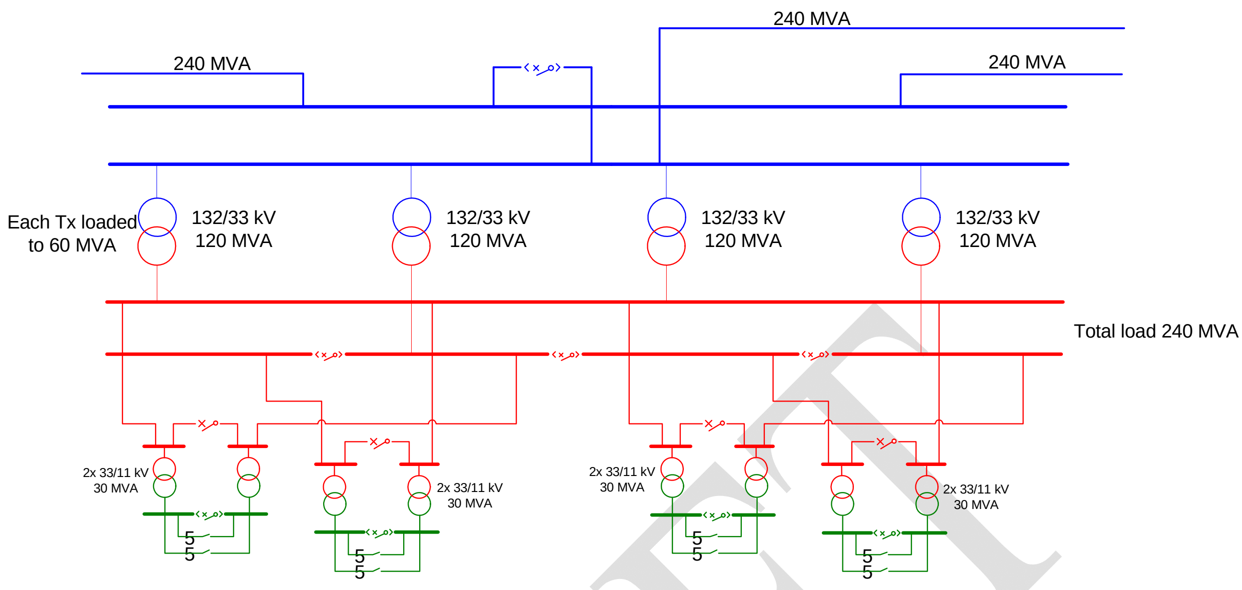


- Figure 43 Distribution Network Architecture Option G

D.5 Alternative Voltage Option

D.5.1 Option H – 33 kV Option

A final option to consider is the incorporation of 33 kV into the distribution network. This option is similar to Option E in that one large substation would be built, but the site would have four 120 MVA, 132/33 kV transformers with further 33/11 kV step-down transformers. Because only one substation would be installed, three 132 kV circuits rated at 240 MVA each would be required to ensure N-2 compliance. It should be noted the use of larger transformers for Option E, as shown in this option, were not considered practical as previous experience has not shown another utility using a 120 MVA, 132/22 or 132/11/11 kV transformer. However, the use of 120 MVA, 132/33 kV transformers has been seen before. Figure 44 shows the architecture for this option.



- **Figure 44 Distribution Network Architecture Option H**

This option has the advantage of introducing a new distribution voltage level to help support the 11 kV network. New block loads could be supplied at 33 kV, freeing up additional capacity at 11 kV. Also, the 33/11 kV step-down transformers could be strategically positioned to supply local load as it materialises.

However, the size of the substation would be quite large. Identifying route corridors may also be difficult for this option, as three 132 kV circuits would be introduced into the Perth CBD Boundary. This option is incapable of minimal staging, thereby increasing upfront capital expenditure. Additionally, no support is offered for a HILP event. A fire at the zone substation, for example, could disrupt the entire supply as there is no means to support the load demand via neighbouring substations.

D.6 Comparison of greenfield Distribution Architectures

In order to determine which distribution architecture option provides the most net benefits and should be considered for expansion of the CBD Load Area, it is important to consider a few other factors. High level costing of each option has been undertaken to get an impression of the costs of each option versus the other. It should be noted, however, that these options have been developed on a greenfield basis with no consideration of the practical limitations of the existing network. The practical limitations will be reviewed and discussed further in the Objective 3 report. After considering the relative advantages and disadvantages of each option, an option for future expansion can be suggested for further analysis.

D.6.1 High Level Costing and Performance

An initial assessment of the costs associated with each option has been undertaken. This assessment is very high level, but provides an indication of how much each option may cost versus the others. The costs have been developed using standard Western Power cost building blocks.

Where equipment deviates from the building block, a weighting factor was introduced to try to give a realistic difference in costs. This assessment does not take into account the additional costs of real estate or easements and it should be noted that both of these additional items may increase the high level cost significantly. The column entitled “NPC* P.U.” indicates the percentage difference from 100% (i.e. lowest cost option, Option E, is 100% with all other options being more expensive).

Additionally, the performance of each option under N, N-1 and N-2 network operation has been compared. The options vary in the amount of power delivered for N and N-1, but all achieve the same target of 240 MVA under N-2 network operation. Also, the underutilisation of assets has been highlighted. That is to say the excess installed capacity for both the transmission lines and the transformers to supply a total load of 240 MVA under normal network operation. This provides an additional indicator that may be used to rank the options. Table 14 shows the high level costs and network capability for each option.

In order to ensure a fair comparison, each option has been compared on the basis of providing 240 MVA under N-2 network operation. This means that Option E needs to be adjusted to be able to provide 240 MVA rather than 150 MVA. To do so, it has been assumed that four 120 MVA, 132/22 kV transformers would be used with three 240 MVA, 132 kV transmission lines.

The results of the high level costing exercise indicate that the single substation option, Option E, is the least cost option in terms of electrical equipment. The most expensive option was found to be the three substation option utilising DTC, Option F. It was also found that Options C and C* provide the highest amount of N-1 support for the network due to the number of transformers and transmission lines installed to support N-2.

However, in terms of equipment utilisation, Table 14 indicates that Options A and B have the highest utilisation factor for installed transmission lines while Options F, F* and G provide the highest utilisation factor for installed transformers. Taking this into account, Options B and D should be considered further where opportunities exist to establish new zone substations within the CBD Load Area. This recommendation has been made based on the analysis presented throughout this report, particularly in Section 3.5, as Options B and D demonstrate the extremes of the analysis through support through the distribution network and support through the transmission network.

Table 14 High Level Costs and Network Capability of Each Option

Descriptions	NPC*, Costs (AUS$ Mil.)	Rank	NPC* P.U	Sub-system loading *MVA)	N-1 capacity (MVA per system)	N-2 capacity (MVA per system)	Installed Tx Line Utilisation Factor	Installed Tranny Utilisation Factor
Option A: Two-substations, 11kV 120MVA in DTC (40 x 240 cu - 6 MVA ea. - cables 50% loaded) EG. between Milligan and Hay str for N-2 (3 hrs)	$158.60	3	114%	240	360	240	50%	50%
Option B: Two-substations, 22kV 120MVA in DTC (20 x 240 cu - 12 MVA ea. - cables 50% loaded) EG. between Milligan and Hay str for N-2 (3 hrs)	$153.12	2	110%	240	360	240	50%	50%
Option C: Two-substations, three lines in for N-2, transformers firm, 22kV rings out (shorter than DTC)	$179.09	5	129%	240	420	240	33%	50%
Option C*: Two-substations, three lines in for N-2, transformers firm, 22kV rings out, two transformers connected to other sub (longer lengths of 132kV cable)	$181.12	7	131%	240	420	240	33%	50%
Option D: Two substations, two lines plus 132kV express line in for N-2 , transformers firm (3 off), 11 or 22kV rings out	$175.15	4	126%	240	360	240	40%	50%
Option E: One substation. Three OHL lines in for N-2, 132/22 or 11kV (reconnectable) 120 MVA transformers firm (4 off) to achieve 240 MVA at N-2, 11 or 22kV rings out	$138.63	1	100%	150	360	240	33%	50%
Option F: Three substations 132/22kV. Two lines in for N-2 at each sub (utilises DTC), line transformers firm (2 off)	$193.50	10	140%	240	300	240	33%	67%
Option F*: Three substations 132/22kV. One line in at each sub (utilises DTC), line transformers firm (2 off), 132kV express lines between subs	$185.88	8	134%	240	300	240	33%	67%
Option G: Three substations 132/22kV. One line in at each sub (utilises DTC), line transformers firm (2 off), 132kV express lines between subs, 3rd sub no DTC	$186.10	9	134%	240	300	240	33%	67%
Option H: One substation. Three OHL lines in for N-2, transformers firm (4 off), 33kV rings out and 33/11kV step downs	$180.34	6	130%	240	360	240	33%	50%

**Net Present Costs*

Appendix E Transmission Network Architecture Options

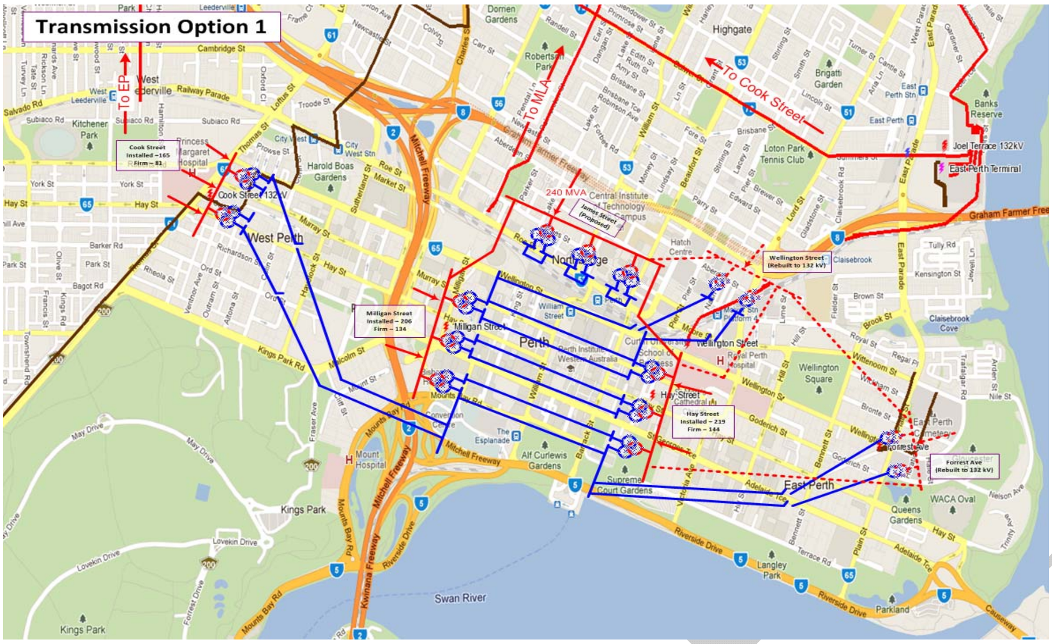
E.1 Transmission Network Architecture Options

A number of transmission architecture options have been developed to present a high level overview of possible network expansion. All of the options look to strengthen the 132 kV network within the CBD Load Area through either the transmission network, distribution network or both. For the reasons stated in Section 1.2.2, a brownfield approach was used for this analysis. It was therefore deemed prudent to undertake the analysis recognising the options outlined in Appendix D and apply other considerations that would arise in the CBD Load Area environment.

E.1.1 Option 1 – 132 kV Transmission Ring

The first option developed involves building one new large substation in the vicinity of James Street. This substation would be capable of supporting a full 240 MVA of load demand, similar to distribution Option E. One new 132 kV circuit, rated to 240 MVA, would be required into the site, potentially using the same corridor as the existing MLA-MIL double circuit, and 132 kV circuits installed to connect the new substation to Hay Street and Milligan Street. This would provide N-2 support for the new site at the 132 kV level. It is recognised the MLA-MIL circuits transition from overhead line circuits to cable circuits at the existing James Street site. Project specific factors, however, such as the ability to use the existing circuits to supply James Street have not been fully considered in this report. Further consideration has been given to this in the East Perth and CBD Load Area Development Report [3].

This option also examines the possibility of rebuilding Wellington Street and Forrest Avenue, after the sites are decommissioned, to 132/11/11 kV substations. The 132 kV network could be further extended by installing circuits between the new James Street substation and Wellington Street, Wellington Street and Hay Street, Wellington Street and Forrest Avenue and Forrest Avenue and Hay Street. This would provide a completely interconnected 132 kV system in the CBD Load Area and provide a large amount of support in the event of a transmission element failure. Figure 45 shows this transmission network option.



- **Figure 45 Transmission Network Architecture Option 1**

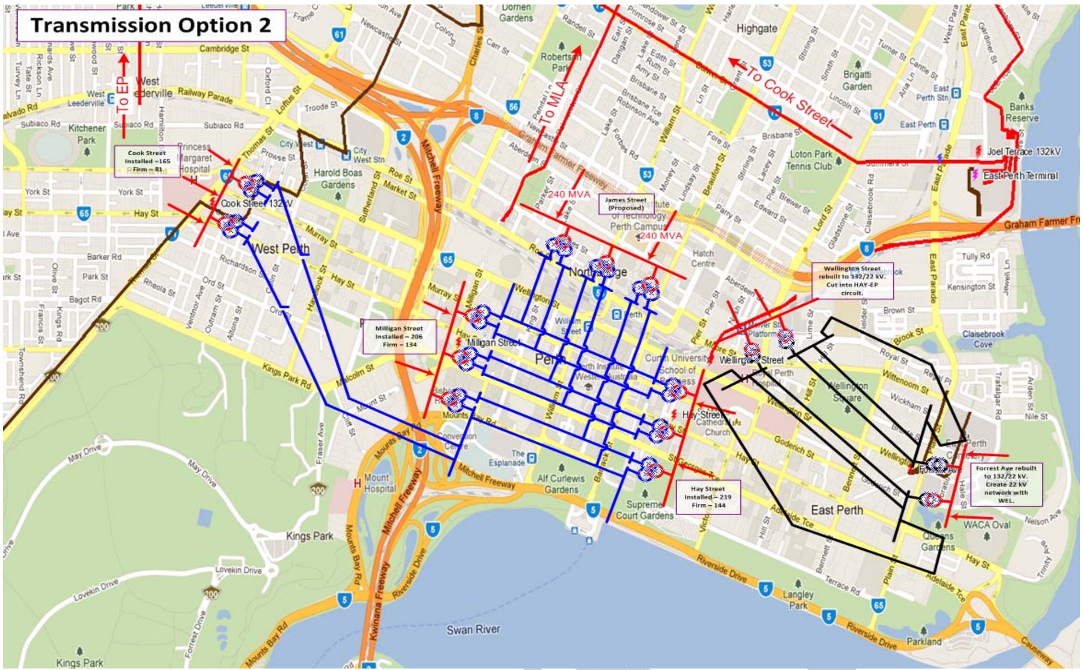
The advantages to this network architecture include the need for only one new substation in the CBD Load Area thereby reducing the amount of real estate required. As previously stated, network security would be greatly improved at the transmission level as a number of 132 kV circuits would be in operation. This option also provides a staged solution, as the new site could at first be built with fewer transformers until the load materialises, delaying the need for total upfront investment.

However, a major disadvantage of this option is the need for three 132 kV circuits at James Street initially (one from Mount Lawley, one to Milligan Street and Hay Street, respectively). This could be a major obstacle as finding cable routes and corridors through the city for 132 kV cables could be quite challenging.

E.1.2 Option 2 – Wellington Street and Forrest Avenue to 132/22 kV Substations

This option again calls for the establishment of a new zone substation at James Street. Instead of interconnecting the substations at 132 kV, the DTC scheme between Milligan Street and Hay Street would be extended to James Street. This option would be similar to distribution Option F. At a transmission level, two 240 MVA, 132 kV circuits (likely from Northern Terminal) would be required to supply the new substation in order to ensure N-1 compliance. There could be an advantage in utilising transformers with reconfigurable secondary windings, i.e. 132/11 kV reconfigurable to 22 kV. While it may be necessary to initially operate the distribution network at 11 kV, this would enable a more efficient migration to 22 kV in the future.

Option 2 also proposes rebuilding Wellington Street and Forrest Avenue to 132/22 kV substations and interconnecting at 22 kV to establish a new distribution voltage in the CBD Load Area, similar to distribution Option B where two 132/22 kV substations heavily interconnected at the distribution level were proposed, outlined in Section D.1.2. This would allow for a natural progression to 22 kV, while extending the current 11 kV system in the CBD Load Area. Figure 46 shows the CBD Load Area under this option.



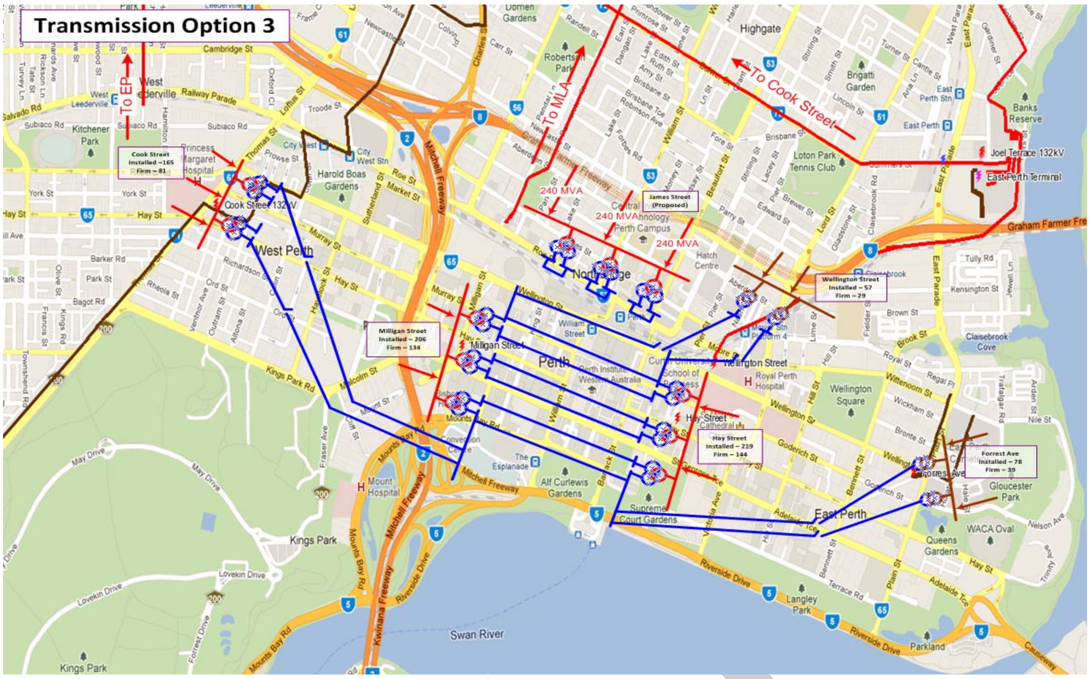
- **Figure 46 Transmission Network Architecture Option 2**

This option has the advantage of creating a strong interconnected 11 kV system in the CBD Load Area while facilitating a move to a 22 kV network to support the load growth. Only one new site is required, similar to Option 1. Staging of this option can be achieved as extension of the DTC scheme to the new James Street substation provides the necessary N-2 support to remain compliant with the Technical Rules.

The disadvantages for this option include a large amount of 11 kV cable works in order to extend the DTC between Hay Street and Milligan Street and the new James Street site. But this substation only needs to be built if load growth in the existing Perth CBD Boundary surpasses current capabilities. An additional 132 kV circuit would also be required from Mount Lawley to James St, needing potentially more easements.

E.1.3 Option 3 – One New Zone Substation

Option 3 explores the possibility of adding only one new 132/22 kV zone substation at James Street, similar to distribution Option E. The substation would be independent from the rest of the CBD Load Area network and be responsible for picking up new load. This option would require three 132 kV circuits into the new site at James Street for N-2 security, but could be established with only 2 circuits initially provided the load it served was outside the existing Perth CBD Boundary.



■ **Figure 47 Transmission Network Architecture Option 3**

By building one new zone substation, new cable routes into the Perth CBD Boundary are minimised. In addition, real estate costs are minimised as only one site need be acquired to build the substation. New load in the Perth CBD Boundary can be supplied at 22 kV. This option also has the advantage of being able to be staged as the load materialises.

However, this option potentially requires three 132 kV circuits to supply the new substation, depending on the location of load connected to it. This could be difficult as it would require multiple easements. Also, this option does not improve transfer capability within the Perth CBD Boundary, instead building an autonomous site capable of supplying the new load independently. In addition, if load does not materialise near the site, the substation will not be situated in an optimal location.

E.1.4 Option 4 – Satellite Substations

The fourth option considered for transmission architecture in the CBD Load Area utilises a concept of satellite substations positioned strategically to supply new load. This would require rebuilding Forrest Avenue after decommissioning to have one 132/11/11 kV transformer, establishing a site at James Street with one 132/11/11 kV transformer and installing one 132/11/11 kV transformer near the Perth Waterfront development. One 132 kV circuit at James Street and one at Forrest Avenue could provide the supply to the network and a 132 kV ring would be built between the new sites to support N-2 compliance. 11 kV interconnections would be established, further extending the DTC scheme between Perth CBD Boundary sites. This can be seen as a variation of distribution Option A. Figure 48 shows this architecture option.

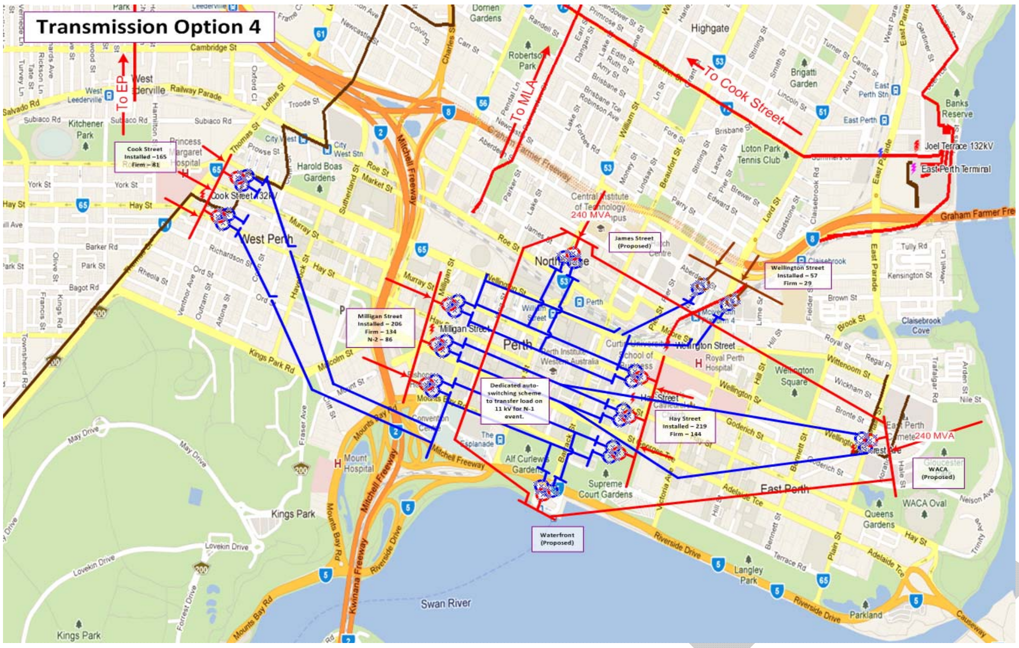


Figure 48 Transmission Network Architecture Option 4

The advantages of this option include installing transformers close to the load as it materialises. It also benefits from establishing a strong 132 kV ring to support transfers between sites. This option can also be staged as the load materialises, utilising the 11 kV interconnections until the 132 kV ring is fully complete.

The disadvantages to this option include a lot of 11 kV cable work throughout the CBD Load Area to interconnect the sites. This could present a problem if new cable routes cannot be identified. Also, a new site near the waterfront would need to be identified in order to install the transformer near the new load. Additionally, this option requires three 132 kV cable routes through the Perth CBD Boundary presenting another cable corridor issue.

Appendix F Demand Management Techniques

There are a number of demand side measures that may be used, either individually or in combination, to relieve network constraints. Each of these measures addresses specific network constraint problems and has specific applicable success factors which determine their effectiveness in achieving network related objectives. Some of these are described below:

1) **Distributed Generation, including standby generation:** Distributed Generation, also called Embedded Generation, is relatively small generators which inject energy directly into the distribution network, close to the load. They can be used to provide network support at specific geographical locations or can be installed to reduce demand at the time of network peak, called peak lopping. They can also be used to reduce network losses, improve utilisation (load factor) and provide voltage support specifically on long rural feeders. Generally, utilising existing stand-by generation instead of installing new generation is more cost effective. However, there can be significant costs involved in connecting these generators to the distribution network to meet technical requirements.

2) **Demand Response:** Demand Response comprises actions taken to reduce electricity consumption at the customers' premises in response to constraints on the supply side. Typically, demand response is used by utilities to provide targeted demand reduction during peak demand periods. The effectiveness of demand response depends critically on the speed with which it can be implemented in response to a network constraint. If the utility has direct control of demand response, the response to a network constraint would generally be more reliable. An example of demand response would be the direct load control of air conditioners.

3) **Energy Efficiency:** Energy Efficiency refers to techniques to reduce the amount of energy required to produce the same output or service. Generally, energy efficiency techniques reduce the overall consumption of energy (i.e. kWh) on the electricity network and, therefore, can be used to slow the overall load growth. These techniques can also be deployed in geographical areas to reduce demand on a substation load area. However, they are difficult to target accurately. Energy Efficiency programs can also generate regulatory and community engagement benefits.

4) **Fuel Substitution:** Fuel Substitution refers to the replacement of electricity with other fuels as a result of which the loads are effectively lost to electricity, possibly permanently. These measures reduce the overall electricity demand across the network but could also be targeted in a specific geographical area or applied to specific loads. Western Power's Green Town project successfully used fuel substitution as one of its demand side measures in the towns of Denmark & Walpole to reduce peak demand. Rebates were offered to customers in the target area on certain appliances contributing to peak demand.

5) **Interruptible Loads:** Interruptible Loads is similar to direct load control techniques and refers to measures where the utility interrupts supply to a customer load based on an existing agreement or contract typically during a network emergency. Typically, the utility has direct

control of the interruptible loads and therefore the response to a network constraint event can be very quick and reliable. Since load interruption can be disruptive to customers, especially if they occur at short notice, some form of reward or compensation is generally provided to customers for their time and effort. Generally, load interruption measures are best suited to achieving short term load reductions for up to a couple of hours. Western Power has load interruption agreements with some major customers; however, they have rarely been used.

6) **Load Shifting:** Load Shifting is a fundamental demand side measure and involves altering electricity use patterns such that on-peak energy use is shifted to off-peak periods. Typically, it involves the utility sending advance notification to the end use customers to alter their electricity use patterns in return for some compensation or discounted tariff.

7) **Power Factor Correction:** Power factor correction seeks to reduce energy wastage by reducing the difference between real power in watts and the apparent power in kVA. Typically, power factor correction measures reduce the overall demand on the network and can be effective if employed in load areas with predominately industrial or commercial loads. They usually involve installation of capacitors near the load on customer's premises, to improve power factor.

8) **Pricing initiatives, including Time of Use and demand based tariffs:** Demand side measures based on pricing initiatives involve changing customer's energy use behaviour on a voluntary basis, in response to various pricing signals. Typically, pricing initiatives are applied to specific customer classes across the whole network and are not restricted to targeted geographical areas. Different types of pricing structures can be used, either individually, or in combination, to encourage customers to alter their energy use behaviour, namely, Time-Of-Use, Real-time Pricing and Critical Peak Pricing. These measures must take into account the disaggregated electricity market structure and must also conform to government policies and regulatory regimes.

9) **Measures using smart grid:** The roll out of smart grids provides an enabling technology platform which can be used to implement a number of demand side measures. Smart grids can enable the implementation of demand side measures in the following ways:

    a) Smart meters are capable of implementing time varying pricing tariffs which can be used as part of price based programs to help change customer's energy use behaviour.
    b) Interval data from smart meters can be analysed and made available to customers to help them identify their energy use patterns and find opportunities to implement energy savings.
    c) Smart grid infrastructure can also be used to implement direct load control programs for specific appliances to enable the utility to reduce electricity consumption at the customers' premises in response to constraints on the supply side in a targeted manner.

As part of the Perth Solar City program, Western Power has implemented a direct load control of air conditioners with good results.

Costs

The actual cost of demand side projects depends upon the specific measures used and the circumstance in which they are implemented. Therefore, it is difficult to provide generalised costs without further information on the specific network constraint being targeted and the demand side technique proposed. However, it is possible to identify general categories of costs that are likely to be borne by the project proponent (in this case Western Power) for all demand side projects:

1) Set up costs: These are one off costs that may include:

    a) Project planning, design and testing costs
    b) Marketing costs
    c) Cost of purchase and installation of equipment

2) Operating Costs:

    a) Payments to project participants such as customers and third parties, in the form of incentives and/or subsidies.
    b) Project operation and management costs

It should be noted that the costs and benefits of demand side projects may also be borne by a number of different stakeholders including consumers, electricity retailers and other electricity market participants. A good framework to assess the costs and benefits of demand side projects is provided in the "California Standard Practice Manual" [23], which was originally developed in California to evaluate utility sponsored DM programs. This methodology has not yet been applied by Western Power to assess demand side alternatives.

Existing DM Projects in the Western Power Network

As an example, indicative costs for a specific demand side measure, namely distributed generation, are given below. These costs have been taken from a DM feasibility study undertaken by Western Power for the North Country Reinforcement project.

Generally, distributed generation, consisting of stand-by generation, is made up of the following cost components:

1) **Availability Charge:** Availability Charges are costs to be paid to the customer to have their generator available and ready to be dispatched.
2) **Dispatch Costs:** Dispatch Costs are charges to be paid to the customer upon actual dispatch of the generator and covers the generator running costs.
3) **Project Management Costs:** Project management costs are paid to the manager of the project to cover planning, design and implementation of the programme.

For the DM feasibility study mentioned above, these costs were:

Availability Charge: $[redacted] per month per MW, for the months for which demand response is required, generally 4 summer months from December to March.

Dispatch Costs: $[redacted] per MWh, for when the generator was dispatched.

Project Management Costs: $[redacted] per month for six months prior to project implementation and again during peak demand months.

Appendix G Multi-Use Building Case Study

A practical example of both GIS and multi-use building technology is the reconstruction of Dewar Place 275/33 kV Substation in Edinburgh, UK[19]. The substation is located in a congested commercial and financial area with many high-profile, high security customers and housed in a building of noted historical significance [24]. The site was reconstructed due to the unavailability of alternative sites in the vicinity, resulting in a complex construction programme required to continue supply to the existing distribution network.

The site was originally an outdoor substation with the 33 kV switchgear, telecoms, offices and loading bay housed in a listed building. This required the façade of the building to be retained whilst the interior would be adapted to accommodate new electrical equipment; any extension would need to blend with the existing structure and façade [24]. Figure 49 shows an aerial view of the substation prior to reconstruction.

[19] http://www.watermangroup.com/projects/get?id=62.

▪ **Figure 49 Aerial View of Dewar Place Substation [24]**

A number of constraints existed around the reconstruction of the substation. The constraints focused mainly on the age and condition of the existing building and the ability of the new structure to complement and be accepted as an integral part of the new development. In order to address the constraints, a number of options were developed. The options were as follows:

Option 1 - Replace Plant in situ and Refurbish Building

This option appeared to be the simplest, however offered little support to the plans to develop the area of the city and did not address all technical risks. At the time of replacement, a light rail network was being developed for the City of Edinburgh and the works would coincide with the new substation, which potentially extended outage periods as extensive railway tunnel strengthening was required. This option was ultimately rejected as the plan did not support the regeneration of the area in line with the aspirations of the Edinburgh City Council [24].

Option 2 - Vertical multi-story structure at Dewar Place, integrated into the existing façade

Under this option, extensive works would have been required to dismantle the existing building. The existing façade would also require extension to house the entire substation indoors. As the scheme called for oil-filled transformers, additional safety measures would be required and incorporated into the design to ensure the building could withstand the effects of an explosion and fire . The design could instead opt for gas insulated transformers which would inherently minimise the risk of fire and explosion [24].

Option 3 - Integrated substation and development

The design for Option 3 focused on a ground floor substation development with intermediate loading deck upon which an additional development could be constructed. This design would require gas insulated units, as space would be limited, resulting in a complex programme with more construction risk. The use of gas insulated equipment served to minimise the risk of fire and explosion, but presented other problems associated with access, electromagnetic compatibility and earthing. An advantage of this option was the release of maximum area for new development and integration into the major development plan for the area [24].

The selected solution

Option 3 was ultimately chosen as the design for the new substation, utilising gas insulted equipment throughout the site. As the existing façade could not be demolished, a greater amount of detail was required to satisfy the operational and development needs of the project [24]. Work is currently on-going for reconstruction of the substation. A series of buildings are planned for the master-plan though specific use has not been confirmed at this time. These may include:

- Commercial office - with retail at ground floor/1st floor
- Hotel with retail or restaurant/bar/café facilities at ground floor level
- Residential or student accommodation with the same ground floor flexibility as above

This case study serves as a good example of the issues faced when constructing or reconstructing a substation in a CBD. Similar design ideas may be required for any new substations proposed as part of the later CBD Load Area development strategies.

Appendix H Network Performance of Hay and Milligan Street

The table below lists N-1 and N-2 contingency data from 1993 to present at Hay and Milligan Street Substations. Note that loss of a 132 kV incoming feeder and its associated transformer is not an N-2 event due to the configuration of the switchgear at the substation. These events are treated as N-1 contingencies.

- **Table 15 Hay Street Substation Performance 1993 to Present, Coloured Bars are Double-Contingencies**

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
EP-HAY 82	Unknown	Unknown	Line (General)	1931		70		23	08-Oct-93	Mesh	
EP-W 71	Equipment	CB: Explosion	Line (General)	2003	10		20.2		28-Jun-95	Mesh	A fault on Capacitor 31 failed to clear via its breaker. A possible busbar flashover appears to have occurred before the fault cleared. Partial restoration of load at 23:41 hrs& full restoration (approx 3MW) at 03:15 hrs.
EP-HAY 81	Environment	Lightning/Thunderstorms	Line (General)	1931	20		0.2		23-May-94	Mesh	The line was restored at 1310 hours the next day - a leaning pole had to be repaired. The sub was restored within 30 seconds via the auto sequence switching scheme.
HAY T1	Equipment	CB: Failure	Power Transformer	2003					29-Jun-95	Mesh	Transformer 1 tripped when Bus-coupler at Hay Street was closed. Damaged Pilot cable at Wellington St stopped Tx 1 restoration. See also SD #1332/A. Total system interruptions on 1332/A.
HAY T3	Equipment	CB: Failure	Power Transformer	2003					29-Jun-95	Mesh	Transformer 3 trip caused by damaged Pilot cable at Wellington St substation. See also SD #1332/A. Total system interruptions on 1332/A.
HAY T1	Unknown	Unknown	Power Transformer	2181					28-Dec-95	Mesh	
EP-HAY 81	Environment	Lightning/Thunderstorms	Line (General)	2181					19-Jun-96	Mesh	The auto sequence switching operated hence there was no loss of load.
EP-HAY 81	Equipment	Protection Failure	Line (General)	2228					14-Apr-97	Mesh	A faulty Earth fault relay at East Perth initiated the intertrip to HAY St. The line was restored to service at 08.55 hrs.
HAY T3	Equipment	Protection Failure	Power Transformer	2228					14-Apr-97	Mesh	A faulty Earth fault relay at East Perth initiated the intertrip to HAY St. Transformer T3 at Hay Street trips with the EP-HAY 81 line. The line was restored at 08.55hrs and the transformer at 09.32hrs. The auto sequence switching scheme operated successfully
EP-HAY 81	WP Staff	WSB Protection Error	Line (General)	2228					14-Apr-97	Mesh	During testing to investigate the relay failure which occurred at 07.05hrs the line was inadvertantly tripped. It was returned to service at 14.25hrs

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
HAY T3	WP Staff	WSB Protection Error	Power Transformer	2228					14-Apr-97	Mesh	Tripped during testing to investigate the relay failure at 07.05hrs. The transformer trips with the EP-HAY 81 line. The line was restored at 14.25hrs and the transformer at 15.03hrs. The auto sequence switching scheme operated successfully to restore the
EP-HAY 81	Equipment	Protection Failure	Line (General)	2228					21-Apr-97	Mesh	The line tripped due to operation of the earth fault relay at East Perth. No load was lost due to operation of the Auto Sequence Switching Scheme. An earlier incident led to a suspicion of a faulty relay which had been replaced. Due to this it was decide
HAY T3	Equipment	Protection Failure	Power Transformer	2228					21-Apr-97	Mesh	The transformer tripped due to operation of the earth fault relay at EP The transformer trips with the EP-HAY 82 line. The auto sequence switching scheme operated successfully to restore the load after a 10sec delay.
EP-HAY 81	Equipment	ISOLATOR: Failure	Line (General)	2228					22-Apr-97	Mesh	The line tripped due to operation of the earth fault relay at East Perth. Initially it was thought that the earth fault relay on this and the 82 line were faulty. Subsequent inspection revealed that one of the isolators on 81 line located at Wellington St
HAY T3	Equipment	ISOLATOR: Failure	Power Transformer	2228					22-Apr-97	Mesh	The transformer tripped due to operation of the earth fault relay at EP The transformer trips with the EP-HAY 82 line. The auto sequence switching scheme operated successfully to restore the load after a 10sec delay.
EP-HAY 81	Equipment	TX: Oil/Gas/Pressure	Line (General)	2228					21-Jun-97	Mesh	The transformer gas trip alarm was received. Transformer T3 at Hay Street was found to have a low oil level. A subsequent inspection found that the oil level float was badly set. The auto sequence switching scheme operated incompletely. The line was returned
HAY T3	Equipment	TX: Oil/Gas/Pressure	Power Transformer	2228	10		0.5		21-Jun-97	Mesh	The transformer gas trip alarm was received. Transformer T3 at Hay Street was found to have a low oil level. A subsequent inspection found that the oil level float was badly set. The auto sequence switching scheme operated incompletely. The transformer left
EP-HAY 81	Equipment	LINE: Failure	Pole/Tower	2456					17-Sep-97	Mesh	Pole number 9A North caught fire due to possible induction from guard wire strung below conductors.

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
HAY T1	WP Staff	Switching Operation	Power Transformer	2346	7.5		0.25		19-Sep-98	Mesh	HAY304 operated instead of HAY340.0 on planned switching programme.
HAY T3	WP Staff	Switching Operation	Busbar (Multiple Circuits)	2346	3.3		0.11		19-Feb-99	Mesh	While switching on programe N1/926/PA, the SOC mistakenly tripped Hay 351.0 ocb (HAY T3-P) instead of Hay 315.0 (HAY T1-A) as the programe directed. Realising the mistake, the SOC re-energised Hay 351.0 ocb, then contacted NOCC and tripped Hay 315.0 ocb.
EP-HAY 81	Public	Contact with Plant	Line (General)	2346					12-Apr-99	Mesh	Line tripped due to a star picket being driven through a pilot cable. Line I/trip took T3 off at HAY Re disturbance no. 2621
HAY T3	Equipment	Pilot Cable	Power Transformer	2346	30.5		3.55		12-Apr-99	Mesh	T3 tripped via I/trip for fault on EP-HAY 81 line. A.S.S. partial operation due to loss of both local supplies. Delay in supply restoration to the B S R & P bars. Re disturbance report no. 2620 for prot flag details.
EP-HAY 82	Public	Contact with Plant	Pilot Cable	2446					24-Aug-99	Mesh	3-pilot cables were damaged on the corner of Summer St and East Pde, East Perth. The EP-W-HAY82 line and HAY Tx 1 were taken out of service as both pilot protections were damaged. Other circuits affected. EP-NP71, EP-WT81, EP-W71, see report #2682 for mo
EP-HAY 82	Equipment	ISOLATOR: Failure	Line (General)	2446					04-Oct-99	Mesh	Line tripped due to isolator W802.5 not closed properly. 2 phases out.
HAY T1	Equipment	ISOLATOR: Failure	Power Transformer	2446					04-Oct-99	Mesh	T1 trip due to I/trip from EP-HAY82 line fault. Re fault report 2710. Customer supplies restored via auto sequential switching.
EP-HAY 81	Equipment	ISOLATOR: Failure	Line (General)	2446					04-Oct-99	Mesh	Isolator W801.5 not closed correctly. Centre phase not made. Arcing tip gone, moving contact melted. Line de-energised manually after Hay s/s off loaded. Isolator contacts replaced.
HAY T3	WP Staff	WSB Protection Error	Circuit Breaker	2599					11-Mar-01	Mesh	CB Tripped was HAY 351.0 During protection mtce CT wiring was disconnected. On restoration CT wiring flashed over tripping CB and damaging circuit cards in battery charger. No Customer supplies affected. No Flags
HAY Buszone (132kV)	WP Staff	Non Operational Staff	Busbar (Multiple Circuits)	2599					14-May-01	Mesh	Hay Street 132kV busbar 8A2 tripped via transformer 2 winding or oil temp. Contractor working around transformer 2 which was out of service. No load lost as T1 and T3 remained in service.

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
HAY T1	Public	Contact with Plant	Power Transformer	2599	7.9		10		07-Jun-01	Mesh	Winding T1D tripped. Loss of Supply to 11kV busbars D and F. Load transferred onto other feeders by NOCC. Winding T2E on Transformer T2 also tripped (refer #3317). Probable cause was cable fault on frd 329.0. Busbars D and F to remain out of service
HAY T2	Public	Contact with Plant	Power Transformer	2599	7.7		9.75		07-Jun-01	Mesh	Winding T2E tripped. Loss of Supply to 11kV busbars E and G. Load transferred onto other feeders by NOCC. Winding T1D on Transformer T1 also tripped (refer #3316). Probable cause was cable fault on frd 329.0. Busbars E and G to remain out of service
HAY Substation	Equipment	Unknown	Busbar (Multiple Circuits)	2679					25-Aug-01	Mesh	Auto Sequential Switching Scheme initiated after operation of the H.V.Bus Section firing into HAY806.0 (open prior to this operation). Protection Staff on site could not confirm the initiation point for this operation. It was found that with the ASSS now
HAY T1	Equipment	CB: Failure	Power Transformer	2679	5.8		1.5		02-Oct-01	Mesh	CB HAY317.0 failed while opening (Refer #3403)
HAY CAP32	Equipment	CB: Failure	Power Transformer	2679					02-Oct-01	Mesh	CB HAY317.0 failed while opening. HAY Transformer T1A LV circuit breaker also tripped Refer (#3402) Note: made available for emergency operations (minimum switching) during summer peak early 2003
HAY CAP37	Equipment	CB: Failure	Circuit Breaker	2679					30-Jan-02	Mesh	Unable to close circuit breaker. Switching programme to isolate for repair. CB out for long duration RTS ttime and date unkown (warranty) Note: made available for emergency service (minimum switching) during summer peak early 2003.
HAY T2	Equipment	CB: Failure	Power Transformer	2886	8.3		0.4		20-Oct-03	Mesh	Tx2H CB - HAY 322.0 Tripped on LV frame leakage. When supply to the HQ bus bars was restored via CB 327.0 the 98 Pier St CB 323.0 tripped with a cable fault. Faulty insulating washers were found and will require replacing. Transformer 2H winding was retur

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
HAY T1	Equipment	CAP/REA/SVC: Failure	Power Transformer	2886	1.6		0.64		09-Feb-04	Mesh	Capacitor HAY C31 tripped and HAY Tx1D tripped at the same time on frame leakage prot. Capacitor CB failed to open properly. Found CB had flashed over refer to SD4465. Load transferred by NOCC.
HAY CAP31	Equipment	CB: Flashover	Circuit Breaker	2886					09-Feb-04	Mesh	Capacitor HAY C31 tripped and HAY Tx1D tripped at the same time on frame leakage prot. Found CB had flashed over. Refer to SD4460.
HAY T3	Public	Contact with Plant	Power Transformer	3256					20-Oct-05	Mesh	Drilling rig cut through the EP-HAY optic fibre cable and pilot cable in Tully Street near Kensington Road East Perth. EP-HAY 81 Line Taken off manually as intertrip did not operate see #5133. The Automatic Sequence Switching Scheme operated successfully
EP-HAY 81	Public	Contact with Plant	Line (General)	3256					20-Oct-05	Mesh	Line Switched out of service by SOCC ref #5132
HAY CAP32	Equipment	CB: Failure	Capacitor	3256					07-Feb-06	Mesh	HAY CAP32 circuit breaker could not be opened via SCADA. CB taken OOS to check.
EP-HAY 81	Public	Non Operational Staff	Cable	3256					18-May-06	Mesh	Line taken out of service following low oil pressure alarms. The cause of the leak ,horizontal boring in Wellington street near the Blood Bank.. Only one core was damaged.
HAY T3	Equipment	Secondary Equipment	Power Transformer	3256					18-May-06	Mesh	EP-HAY 81 cable oil pressure alarm operated causing HAY T3 to trip. Refer to SD 5307. Autotomatic sequence switching scheme restored supply of T3. Report of a slow changeover of supply from head office.
HAY T2	Equipment	Distribution Equipment	Power Transformer	3768	9.9		2.55		04-Mar-10	Mesh	Insulation failure of circuit HAY335 caused " frame leakage protection" to operate resulting in de-energising of 11kV busbar G & E and tripping of transformer HAY T2E circuit breaker HAY333.0. NOCC started restoring customer supply via DTC at 0742hrs
HAY CAP34	Equipment	CB: Failure	Capacitor	3768					04-Mar-10	Mesh	HAY CAP 34 circuit breaker 335 failed to close on remote by SCADA. While attempting to close circuit breaker, insulation failure on circuit caused "frame leakage protection" to operate, resulting in in de-energising of 11kV busbar G & E and tripping
HAY T2	Equipment	Distribution Equipment	Power Transformer	4028	7.29		1.8		18-Sep-10	Mesh	MIL 339.0 tripped on fault. During fault switching to shift MIL 339.0 load to HAY334.0, HAY T2 tripped. HAY T2 load was picked up by DTC starting at 2349hrs.

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
HAY Substation	Equipment	Communication	Line (General)	4028					25-JaN-11	Mesh	EP-HAY 81 VF intertrip equipment failed thus requiring repair. HAY T3 and EP-W-HAY 81 line had to be de-energised to enable comms to repair equipment. Line and Tx RTS after comms equipment repaired.

- **Table 16 Milligan Street Substation Performance 1993 to Present, Coloured Bars are Double-Contingencies**

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
MIL-MLA 81	Environment	Bushfire	Power Transformer	2003	15		0.1		04-Nov-94	Mesh	The auto sequence scheme at Milligan Street resulted in the load on transformer T1 being restored within 10 seconds.
MIL CAP34	Equipment	Protection Failure	Capacitor	2003					11-Dec-94	Mesh	Overcurrent relay tripped both Cap34 and Cap35 banks.
MIL-MLA 82	Equipment	Protection Failure	Line (General)	2228					08-Jul-96	Mesh	There was no supply loss. The 132 kV bus bar protection at Milligan Street operated when item 70 of switching program 1357 was carried out.
MIL-MLA 81	Equipment	Secondary Equipment	Line (General)	2228					26-Jul-96	Mesh	Battery No2 failed at MIL and sent an intertrip to MLA. No prior warning of battery problems. No load was lost
MIL-MLA 82	Public	Vandalism	Line (General)	2228					27-Jan-97	Mesh	Vandals threw wire over 132kV busbar at MLA causing a bus zone protection operation. T3 at MIL lost supply. Auto switching scheme at MIL did not operate causing loss of control on the 11kV buscouplers at MIL. Refer SWDA 1825/A.
MIL T3	Public	Vandalism	Power Transformer	2228	5.5	45	4.5	11	27-Jan-97	Mesh	Vandals threw wire over 132kV busbar at MLA causing a bus zone protection operation. T3 at MIL lost supply. Auto switching scheme at MIL did not operate causing loss of control on the 11kV buscouplers at MIL. Refer SWDA 1824/A.
MIL T3	Equipment	Protection Failure	Power Transformer	2456					20-Jul-97	Mesh	
MIL CAP34	Equipment	Distribution Equipment	Capacitor	2456					02-Jan-98	Mesh	MIL 320.0 tripped on close, cb - cable & cap bank isolated and checked for faults, harmonic recorder put on protection and is still under test
MIL-MLA 81	Equipment	Communication	Line (General)	2346					15-Dec-98	Mesh	Line taken out of service due to VF intertrip failure. (If fault on TX 1 Mil line would not clear fault. No TX protection) VF commstps card found damaged and replaced at MLA end.

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
MIL T1	WP Staff	WSB Protection Error	Power Transformer	2446					30-Jan-00	Mesh	Protection got opposite pilot cables at opposite ends of MLA-JAM-MIL81 and tripped TX1 ASS restored sub.
MIL CAP35	Unknown	Unknown	Capacitor	2599					10-Sep-00	Mesh	Capacitor 35 tripped on fault. Requires further investigation. Note RTS date is estimated
MIL CAP35	Equipment	Secondary Equipment	Capacitor	2599					08-Oct-00	Mesh	It appears that we have 2 problems. 1. Capacitors 320 and 335 should not be on overnight. (Time clock problem) 2. This happened on the 10-09-00 same circuit and flags and investigations found nothing. Note RTS date is estimated
MIL-MLA 81	Equipment	CB: Failure	Circuit Breaker	2599		28		1.16	16-Jun-01	Mesh	CB MLA803.0 b phase pole shattered on opening during switching prog. SO10730 (item 12). Isolator MLA803.4 required repairs prior to the restoration of "x" bus bar
MIL T3	Equipment	CB: Failure	Power Transformer	2679					14-Jan-02	Mesh	MIL306.0 would not close on restoration of switching programme 11975. Latching mechamism repaired .
MIL-MLA 81	Equipment	Pilot Cable	Line (General)	2679					23-Apr-02	Mesh	Car vs pole cnr. Alexander Dve and Central Ave in Morley (street light pole carrying pilot cable). Resulting in damage to pilot cable junction box. Both protections for MIL-MLA 81 line were in pilot cable and there was no standby route to transfer them i
MIL CAP31	Equipment	CAP/REA/SVC: Failure	Capacitor	2679					08-May-02	Mesh	MIL302.0 (CAP31) tripped via intertrip from MIL317.0 (CAP33) Refer SD# 3684
MIL CAP33	Equipment	CAP/REA/SVC: Failure	Capacitor	2679					08-May-02	Mesh	Capacitor out of balance relay did not operate correctly and trip MIL317.0 (CAP33) but intertrip was sent to MIL302 (CAP31) which did trip. Refer SD#3683 MIL302.0 was manually tripped.
MIL CAP35	Equipment	CAP/REA/SVC: Failure	Capacitor	2616					05-Jul-02	Mesh	MIL320.0 (CAP34) tripped with MIL335.0(CAP35). (as it should !) Note: Made available for emergency service (minimum of switching) during summer peak early 2003.
MIL T2	Equipment	Secondary Equipment	Power Transformer	2616					31-Jul-02	Mesh	The Automatic Sequence Switching (ASS) scheme operated to restore supply. Suspect Transformer failure. Circuit breaker MIL310.0 did not trip via the ASS to separate the R and P bus-bars. Trip relay would not reset.

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
MIL CAP34	Unknown	Unknown	Unknown	2616					03-Jun-03	Mesh	Cap 34 tripped when MIL806.0 was closed during SW/prog to isolate MLA-MIL81. Cap 35 intertriped on fault at the same time. Trip indicated Red phase fault on Cap 34. Capacitors checked and RTS.
MIL T2	Equipment	CB: Oil/Gas/Pressure	Circuit Breaker	2886					05-Jan-04	Mesh	Load on T2E winding transferred to enable it be switched out of service to allow repair of close lockout on busbar coupler circuit MIL328.0
MIL Substation	Equipment	CB: Oil/Gas/Pressure	Busbar (Multiple Circuits)	2886					19-Jun-04	Mesh	MIL328.0 Gas Pressure lockout occurred. As this c.b. is normally on, and coupling the 'E-G' busbars it was necessary to offload & de-energise the 'E' & 'G' busbars to enable Maintenance Personnel to regas the c.b. Feeders offloaded were MIL319.0, 321.0,
MIL-MLA 82	Environment	Vegetation Intrusion	Line (General)	3171					13-Aug-04	Mesh	Large palm tree touching line. Line taken oos to cut tree.
MIL Equip not in a Cct	Equipment	CB: Failure	Circuit Breaker	3171					28-Feb-05	Mesh	Mtce requested MIL803.0 A2-A3 Bus Section C.B. to be taken off to replace spring charge motor.
MIL CAP34	Equipment	Distribution Equipment	Capacitor	3171					01-Apr-05	Mesh	Cap 34 tripped at the same time as feeder MIL325.0 was switched off on a programmed job to off load MIL sub. Cap 34 (MIL320.0) tripped on R and W phase IDMT with an intertrip flag. MIL Cap 35 tripped at the same time. Refer to SD4495. Assets Integrity i
MIL CAP35	Equipment	Distribution Equipment	Capacitor	3171					01-Apr-05	Mesh	Cap 35 (MIL335.0) tripped due to intertrip signal sent by Cap 34. Refer to SD4494. NOTE: SD not issued earlier as SCADA switching partitioned to NOCC.
MIL CAP34	Equipment	Unknown	Capacitor	3256					25-Jul-05	Mesh	MIL CAP34 tripped. Suspected cause harmonics. D Potts investigating. Flags: 50
MIL CAP35	Equipment	Unknown	Capacitor	3256					25-Jul-05	Mesh	MIL CAP35 tripped. Suspected cause harmonics. D Potts investigating. Flags: 03, 50, 87
MIL T1	WP Staff	WSB Protection Error	Power Transformer	3256	5		0.42		19-Oct-05	Mesh	Cable Oil Low Pressure Trip on MLA/MIL 81caused tripping of TX1. MLA/MIL 81 was out of service to relocate it for the new metro rail project. The cable protection had not be correctly isolated. The Automatic Sequence Switching Scheme operated to restore s

Circuit	Description of CIGRE disturbance code	Cause of Disturbance Code Description	Code Description for Equipment	System Peak Load (MW)	Lost MW due to Interruption	Lost MW due to Undervoltage	Estimated MWH Lost (Interruption)	Estimated MWH Lost (Undervoltage)	Date of Disturbance	System Configuration	Approved Comments
MIL Equip not in a Cct	Unknown	Unknown	Circuit Breaker	3256	3		0.1		31-Oct-05	Mesh	During a switching program restoration, BusCoupler MIL310.0 tripped without a command being issued by theController at SOCC (Although the SCADA indicates a Controlled Change of State). Supply was lost to some customers. Note that this CB had been closed o
MIL-MLA 82	Environment	Vegetation Intrusion	Line (General)	3256					09-Jan-06	Mesh	Line taken OOS to cut tree close to line.
MIL T3	Equipment	CB: Flashover	Power Transformer	3256					30-May-07	Mesh	Discharge Noise from CB MIL306.0. MIL T3 taken oos.
MIL T1	Equipment	Distribution Equipment	Power Transformer	3768	7.59		10.52		30-Oct-09	Mesh	A feeder fault caused a frame leakage operation, tripping transformer T1D circuit breaker MIL342.0. Investigation showed two feeders had been incorrectly earthed to frame MIL 336 and MIL349. All customers were restored via distribution transfer. System
MIL T2	Equipment	Distribution Equipment	Power Transformer	3768	16.13		5.65		30-Oct-09	Mesh	During switching to isolate faulty section of feeder (refer to SD6519), frame leakage protection operated causing tripping of transformer T2E circuit breaker MIL333.0. Customer loads were restored by distribution transfer. System minutes being verified
MIL T1	Equipment	Communication	Power Transformer	3768					08-JaN-10	Mesh	MIL-MLA81 VF Direct Intertrip defective alarm came up at MLA suspect intertripping scheme faulty. As a result of this decided to take MILT1 and MIL-MLA81 off as could not guarantee i/trip being sent to MLA line C.B. if there was a fault on MILT1. MILT1 o
MIL T1	Equipment	Protection Failure	Power Transformer	4028					08-JaN-11	Mesh	TX1 tripped on planned energisation using CB 806.0. Investigation found differential protection had operated and relay has history of mal-operations. Trial energisation performed and successful.

For more information please contact:

AUSTRALIA Laurie Curro

Sinclair Knight Merz
11th Floor, Durack Centre
263 Adelaide Terrace
PO Box H615
Perth WA 6001 Australia

T: +61 8 9469 4400 E: lcurro@globalskm.com

www.globalskm.com

UNITED KINGDOM Paul Espie

Sinclair Knight Merz
13th Floor, Cale Cross House
156 Pilgrim Street
Newcastle upon Tyne
NE1 6SU

T: +44 191 211 2400 E: pespie@globalskm.com

SINCLAIR KNIGHT MERZ

SKM