Annual Planning
Report 2017

westernpower

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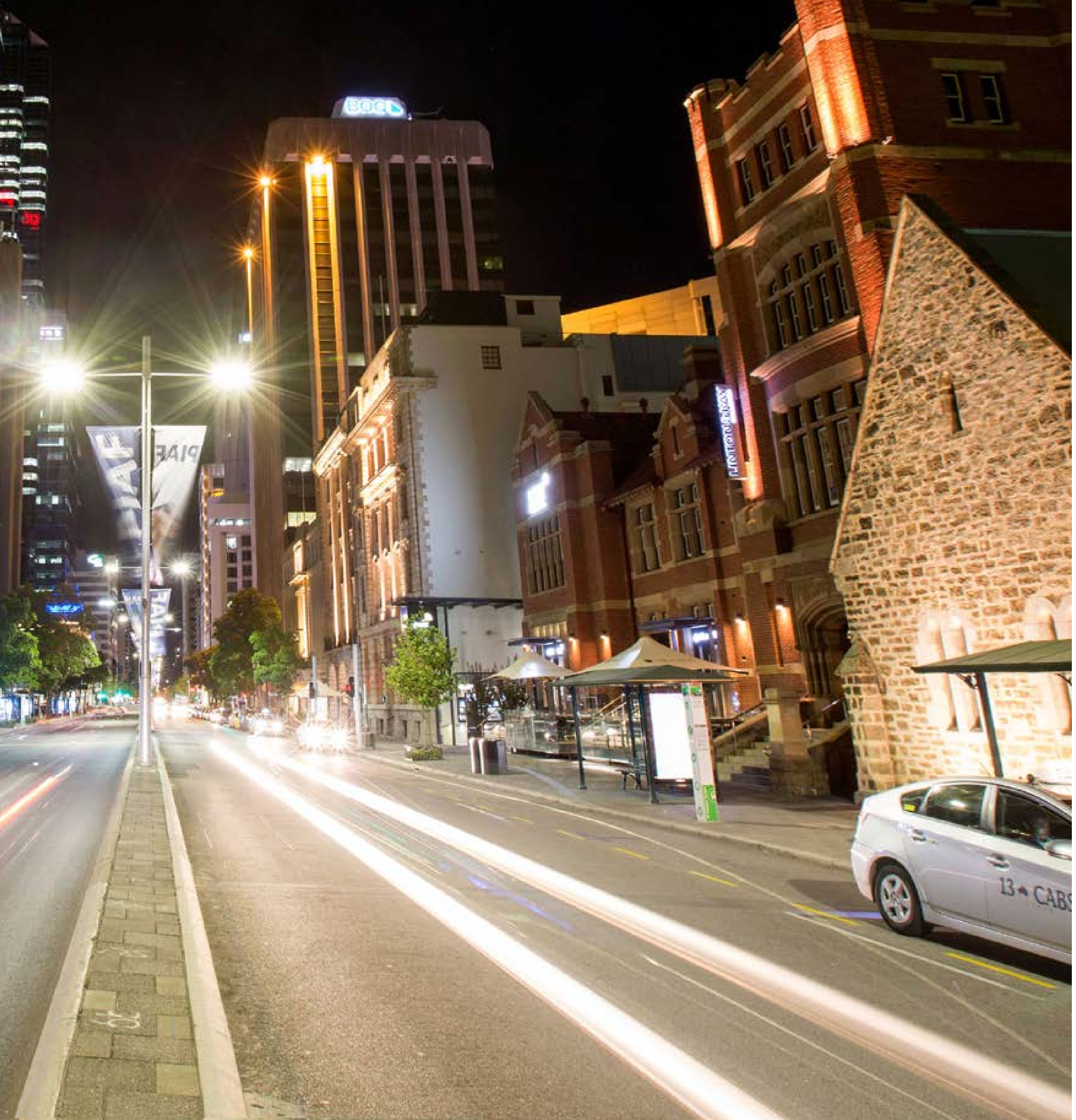

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ANNUAL PLANNING REPORT 2017

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1. INTRODUCTION

1.1 Our role

Western Power is a Western Australian State Government-owned corporation that connects more than one million customers with electricity in a way that is safe, reliable and efficient.

We build, maintain and operate the electricity network in southern Western Australia, across an area bounded by Kalbarri, Albany and Kalgoorlie. The Western Power network forms the vast majority of the South West Interconnected Network (SWIN), which together with all of the electricity generators and consumers, comprises the South West Interconnected System (SWIS).

We are governed by an independent Board and report to the Western Australian Minister for Energy as the owner's representative.

1.2 About the Annual Planning Report

We publish the Annual Planning Report (APR) to provide information to electricity market participants and interested members of the broader Western Australian community on the nature and location of the emerging capacity constraints on the Western Power network.

The APR provides an open and transparent view into the factors we consider in addressing network issues responsibly and efficiently, to produce timely network and non-network solutions to manage both emerging constraints and meet developing evolving customer needs. The APR aims to provide a strategic view of network development, illustrating the foundations for the planning and development of the Western Power network into the future from a whole-of-network perspective.

As the operator of an unconstrained network, Western Power is required to connect generators that apply for a reference service to the network. While in recent years the Wholesale Electricity Market has experienced an over-supply of capacity, Western Power continues to connect generators in line with this obligation and intends the APR to provide guidance on emerging capacity constraints for the benefit of new generator, as well as load connections. Additionally, there is a focus on presenting emerging capacity constraints for the benefit of existing and potential network users.

This report also articulates the guiding principles of the processes through which existing and potential network users (including generators, major loads, local councils and other organisations with planning and development interests) can engage us on the development of network access agreements.

This report is supported by a number of subordinate internal documents containing detailed planning information on issues such as network capability, power reliability and asset performance in discrete areas of the network. Among these are Network Development Plans (NDPs), which articulate the medium-to-long-term planning advice (2 to 50 year horizon) to ensure the efficient development of individual load areas. The NDPs provide more detailed and specific information on potential network developments.

Our customers' needs are dynamic so the information and plans change from year to year and we recognise the importance of keeping the plans up to date. Existing and potential customers are encouraged to contact us to receive specific advice as early as possible[1].

1.3 Interaction with the Electricity Statement of Opportunities

The APR complements the Australian Energy Market Operator (AEMO) Deferred 2015 Electricity Statement of Opportunities,[2] released in June 2016. While the Statement of Opportunities focuses on the overall adequacy of generation capacity, the APR's focus is the identification of emerging network capacity issues and major assets issues and potential solutions for our transmission and distribution networks.

Although these artefacts are prepared separately and from distinct forecasts, they jointly provide a valuable insight into current and future opportunities for new and existing generators, developers and consumers.

1.4 Structure of the 2017 APR

The 2017 APR is similar to the previous year, consultation with key internal and external stakeholders has influenced this year's release and we believe this has improved the usefulness of the document.

1.5 Invitation to provide feedback

We welcome feedback on this APR. Please direct comments on this document to:

Head of Network Planning
Western Power
GPO Box L921
Perth WA 6842
Telephone: (08) 9326 6647

Comments may also be submitted by email to *apr@westernpower.com.au* and through our website.

This APR is based on the most current information available at the time of writing with respect to generation and load development expectations. We welcome contact from parties considering investments that, based on the information provided here, would appear to either:

- delay requirements for network development options, or
- accelerate requirements for network development options.

Relevant information will be incorporated in our planning process and reflected in future editions of the APR.

[1] https://www.westernpower.com.au/connections/new-connections/
[2] https://www.aemo.com.au/-/media/Files/Electricity/WEM/Planning_and_Forecasting/ESOO/2015/Deferred-2015-Electricity-Statement-of-Opportunities-for-the-WEM.pdf

2. PLANNING CONSIDERATIONS

This section presents a high-level overview of the legislative and regulatory requirements that inform our planning processes, together with a description of these processes.

2.1 Electricity regulation in Western Australia

We are subject to a number of regulatory regimes that are administered by the following regulatory bodies:

» Economic Regulation Authority (WA)
» EnergySafety (WA)
» Environmental Protection Agency (Commonwealth)
» Department of Environment Regulation (WA)
» Department of the Environment (Commonwealth)
» Department of Planning (WA)
» Australian Energy Market Operator (AEMO)[3]
» Public Utilities Office (WA)
» Worksafe (WA).

These bodies are responsible for ensuring that our activities are consistent with regulatory requirements, with some having the authority to impose financial penalties and legal action against Western Power should it be found in breach of its obligations.

The main regulations and codes governing Western Power's activities include:

» *Electricity Networks Access Code 2004 ("the Access Code")*
» *Electricity Corporations Act 2005*
» *Code of Conduct for the Supply of Electricity to Small Use Customers 2014*
» *Wholesale Electricity Market Rules 2004*
» *Electricity Industry (Code of Conduct) Regulations 2005*
» *Environmental Protection Act 1986*
» *Planning and Development Act 2005.*

In developing its investment plans, one of the most important pieces of legislation we must consider is the Access Code, which is administered by the ERA. The ERA is an independent economic regulator, whose role is to help ensure we provide a quality service at a reasonable price. The primary regulatory instrument is the Access Arrangement, which the ERA reviews every five years (see Section 2.1.1).

During its Access Arrangement review, the ERA scrutinises the capital investment we undertook in the previous Access Arrangement period to test whether it was efficient and eligible to be added to our Regulated Asset Base (see Section 2.1.4).

The ERA also examines our forward plans to test whether they satisfy the Access Code objective of:

> *"… promoting the economically efficient investment in, operation and use of, networks and services of networks in Western Australia in order to promote competition."* [4]

It is essential that our ongoing operations and investment activities consider this objective, the conditions of the Access Arrangement and the investment tests applied by the ERA to Western Power's activities.

2.1.1 Access Arrangement

The Access Code requires us to have an Access Arrangement approved by the ERA. The Access Arrangement determines the regulated revenue we may receive (e.g. from network tariffs) for connecting customers with electricity, together with the level of service customers can expect during its five-year duration.[5] The Access Arrangement provisions must be approved by the ERA, together with any subsequent amendments.

The Access Arrangement covers:

» regulated revenue we may earn
» charges and conditions for accessing the network, including a standard access contract
» policies on customer contributions, applications and queuing that describe how charges are calculated for customers wishing to connect to the network and the process we follow for processing connection applications
» performance and reliability standards
» performance incentives.

The term of the current Access Arrangement period (AA3) is 1 July 2012 to 30 June 2017. Western Power is due to submit its next Access Arrangement (AA4) to the Economic Regulation Authority (ERA) in October 2017. This is an extension of the legislatively mandated submission date of December 2016, granted by the then Minister for Energy to reflect the change in the regulatory submission's direction from the Australian Energy Regulator (as part of broader energy market reforms) back to the ERA.

AA4 will cover the period from 1 July 2017 to 30 June 2022, providing a further five years of revenue stability for us under the provisions of the Electricity Networks Access Code.

2.1.2 Technical Rules

The Technical Rules prescribe the technical requirements for the design and operation of the network and connection to it, with which Western Power, generators and consumers must comply. These rules form part of the Access Code and provide the technical basis for investment decisions and capital expenditure forecasts.

2.1.3 Regulatory Test

Under Chapter 9 of the Access Code we are required to conduct a Regulatory Test for major augmentation projects whose estimated costs exceed the following thresholds:[6]

» transmission: $36.0 million
» distribution: $12.0 million
» combined transmission and distribution: $36.0 million.

The Regulatory Test requires us to demonstrate the following in relation to solutions we propose to address network issues:

» all viable options have been considered, including non-network options (e.g. contracted demand management and generation support)
» the proposed approach maximises the net benefit to those who

[3] The roles of independent energy market operator and independent power system operator in Western Australia were transferred to the Australian Energy Market Operator (AEMO) as part of the State Government's Electricity Market Review, (Market operations function took effect 30 November 2015).

[4] See ERA site: https://www.erawa.com.au/electricity/electricity-access
[5] The two previous Access Arrangements were both three years in duration.
[6] As at 1 July 2016. These thresholds are indexed annually by the ERA.

generate, transport and consume electricity.

Examples of benefits include improving supply reliability, improving or maintaining safety standards, reducing electricity generation costs and increasing the productivity of electricity consumers through reduced electricity prices.

The Access Code also obliges us to conduct public consultation processes for major augmentation projects.

2.1.4 New Facilities Investment Test

The New Facilities Investment Test (NFIT) is the formal methodology[7] for assessing the efficiency of expenditure and whether we can earn a return on that investment.

Satisfying NFIT is essential for us to recover a full commercial return on investments. The ERA may exclude from our regulated asset base the cost of any investment not satisfying this test, limiting our ability to:

» earn revenue from that investment
» pay back past borrowings
» operate as a sustainable commercial entity.

To minimise the risk of inefficient expenditure, we assess NFIT as part of all investment justifications.

To ensure that we are certain that we have made prudent and efficient investment decisions, it is important that all investment decisions and the considerations made when applying the NFIT are documented and can be provided to the ERA on request.

2.2 Our funding process

As our forecast retained cash flows are not sufficient to meet capital expenditure requirements, debt funding is required. These funds are sourced from the Western Australian Treasury Corporation and therefore have a direct impact on State net debt.

Our State Budget position determines the approved borrowing limits over the forward estimates period. This is co-ordinated by the Department of Treasury and is reviewed twice yearly as part of the State Budget and Mid-Year Review processes. The Minister for Energy is required to endorse any adjustments to the State Budget position we submit.

The approval of any adjustments to the State Budget position over the forward estimates period enables us to update the expenditure forecasts.

[7] Defined in Section 6.52 of the Access Code.

We may also submit funding requests for additional capital expenditure through business cases, as recommended to us by the Expenditure Review Committee in November 2012.

2.3 Our planning processes

2.3.1 Network development planning

Our network development planning applies prudent risk management principles with the aim of optimising the balance between safety considerations, costs and the impact on customers of unreliable or insufficient supply.

The Network Development Plan (NDP) is fundamental to this process, ensuring optimal investment decisions and efficient project delivery to achieve the required outcomes. NDP depends on a range of inputs, including:

» The Technical Rules[8]
» Load and generation forecasts. These are developed from observed historical trends and take into account projections of State economic growth and customer and generator connection enquiries (discussed in detail in Section 3). Our forecasts also make prudent assumptions about the development of generation projects (see Section 4) and consumer usage trends
» Asset management plans. These ensure that network assets can continue to provide a safe and reliable service. Condition assessments drive asset replacement and maintenance activities
» Our commercial objectives, reflecting our legislated obligation to act in a manner likely to maximise the long-term profitability of the business
» The State of the Infrastructure Report. This is an annual snapshot of the performance of the network. It is used by planners and asset managers to ensure that Network Management Plan (NMP) and NDP address identified performance risks.

These inputs are considered within the network analysis to ensure that each network element satisfies a number of technical criteria:

» Ability to operate within design limits. This requires voltage and power transfer for each asset to be assessed under a wide range of potential conditions, including the modelling of the effect of faults on the network. The failure to meet design specifications can result in malfunction or damage to customer equipment, while exceeding power transfer limits creates potential safety hazards and reliability issues arising from the overload and failure of network equipment
» Ability to tolerate credible faults and unplanned outage scenarios. A fault is considered credible if it has a reasonable probability of occurring given the prevailing circumstances
» Ability to continue operating within design limits and at the required performance level in the event of a credible fault or unplanned outage.[9]

Key network planning considerations include:

» maintaining quality of supply[10] to the appropriate standard
» catering adequately for future growth to facilitate economic development, where it is economically prudent to do so
» the responsible management of environmental impacts through formal approval processes and adherence to internal and external environmental management requirements
» stakeholder expectations.

The NDP (2 to 10 year outlook) aims to achieve sufficient capacity for transmitting power from generators to consumers as cost-effectively as possible. This may involve alternative non-network solutions, such as demand management (DM) or local generation support.

From the NDP, detailed plans are developed for the transmission and distribution networks. Detailed system studies are undertaken for a variety of

[8] https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules
[9] The radial nature of the distribution network means that the loss of a network element will generally result in the loss of supplyto a number of customers. We attempt to minimise the impact of these events by installing reclosers, sectionalisers, fault indicators, load break switches and remote control pole-top switches.
[10] Quality of supply encompasses voltage, frequency and other power supply parameters.

load and generation scenarios, in conjunction with investigations to capture network issues and associated drivers.

For the transmission network (66 kV and above), a typical timeframe of up to ten years is considered. Distribution planning (below 66 kV) is limited to a five-year horizon due to lower visibility of block loads beyond that interval and the inherently dynamic characteristics of planning needs.

These activities lead to the preparation of detailed Works Planning Reports (WPRs), which:

- articulate the network issue(s) and driver(s) being addressed
- include a risk assessment of the network issue(s) against set deterministic criteria, including the likelihood and consequences of each risk to determine individual and overall risk ratings
- propose any mitigation measures that may be required prior to implementation of the final solution
- comprehensively evaluate available technical options
- conduct economic and financial analysis on the options
- recommend a solution based on an optimal investment strategy that maximises net benefit
- apply risk-based planning techniques to further quantify net benefits of transmission network augmentation and to define the optimal trigger year for investment[11]
- conceptually describe the project that delivers the solution
- identify the benefits to be realised by the end of the project.

The WPR forms the basis of a business case and regulatory submissions (where required) recommending a solution and seeking approval to proceed with it.

2.3.2 Long-term strategic planning

The long-term strategic planning process guides short and medium-term planning activities by articulating strategic long-term views of the network's evolution. With this view, options for addressing short to medium-term issues can be considered in the context of the network's envisaged future state.

To successfully plan for the long-term, it is necessary to monitor trends and changes in the external environment and their potential impacts on us and our customers.

This involves active participation in various working groups, close engagement with stakeholders and interaction with other electricity sector participants, such as manufacturers and national and international organisations.

Maintaining awareness of energy policy issues is achieved by contributing to reviews of energy policy, the regulatory framework, the Wholesale Electricity Market (WEM), the Technical Rules and the Access Code.

By considering a range of scenarios, we explore the potential impact of uncertain future demand and generation requirements on the network. The scenarios cover a range of potential directions and explore the impact of government policy initiatives. These include emission reduction policies, renewable generation policies and targets and the development of adding new technology solutions.

Effective long-term strategic planning identifies and creates options for short to medium-term planning and projects, as well as maintaining their viability and minimising the risk of their becoming time-critical. This strategic positioning can occur in a variety of ways, including:

- strategic land purchases for future zone substations and terminal stations
- securing access corridors via the strategic statutory planning process (undertaken by the Department of Planning)
- adopting appropriate emerging technologies.

Long-term planning also requires regular environmental scans of the technological landscape to ensure that appropriate standards are in place for the shorter term planning horizon.

[11] The planning criteria in the Technical Rules (current version published 1 December 2016) are inherently deterministic and do not explicitly consider the application of risk-based (or "probabilistic") planning techniques. However, if a decision on a risk-based planning investment conflicts with compliance obligations prescribed in the Technical Rules, we will engage with the ERA to assess the risks associated with the cost of compliance (compared to non-compliance) to determine if an exemption is applicable. This approach is undertaken on a case-by-case basis to reconcile the outcomes of the two planning approaches.

2.3.3 Network Control Services

Through the Regulatory Test and NFIT provisions, the Access Code requires us to demonstrate that we have efficiently minimised costs when implementing a solution to remove a network constraint. In all cases, this requires a comprehensive and robust assessment of all viable options, including Network Control Services[12] (NCS) and other non-network solutions, where available and appropriate. The Access Code regards NCS as an option requiring assessment.

NCS assists in managing network flows to ensure secure and reliable operation and can be provided through demand management and local generation support.

In generation, it may take the form of a power station connected to the transmission or distribution network (or directly to a zone substation) that is operated for a short duration during peak load periods.

In demand management implementations, specific customers may agree to curtail load, run on-site standby generation or disconnect from the network for short periods to reduce their impact on the network during specified conditions (for example, at times of peak load).

NCS is treated as an operating expenditure, in contrast with the capital expenditure treatment of network solutions (e.g. the construction of a new transmission line). The implementation of NCS leads to additional operating expenditure for us that results in the deferral of the capital expenditure associated with the alternate network solution (i.e. where the annualised cost of the network solution is more than the annual cost of NCS). In some cases it may be a connecting block load or generator that agrees to special conditions (under an NCS contract or through special conditions in the connection agreement) in order to defer network augmentation.

If NCS does not appear to be viable, or if its procurement tender process does not yield a satisfactory outcome, we may proceed to implement the network augmentation solution.

Where NCS is implemented to meet general load growth, the costs will be recovered from all customers via network tariffs. In the event of a specific customer driving the need for NCS, applicable costs will be recovered directly from that customer to avoid cross-subsidies from other customers.

The regulatory framework provides for the ability to directly recover operating expenses where appropriate. For NCS, this can be in the form of both a fixed rate plus a rate per kWh to echo the payments made to the service provider for both capacity and energy. It is envisaged that NCS providers would secure capacity payments from the AEMO via its Reserve Capacity Mechanism, so that any capacity payment we make to a NCS provider covers only additional capacity costs incurred (if any).

2.4 Customer contributions and connections

2.4.1 Customer contributions

Customers seeking to connect to our network may be required to make a financial contribution (in addition to the payment of network tariffs) towards the cost of any network augmentation required to facilitate the connection. Customer contributions may be in the form of up-front capital contributions, periodic payments for non-network solutions (such as NCS), or a combination of both.

Customer contributions are determined in accordance with the Contributions Policy,[13] as approved by the ERA as part of our Access Arrangement. In essence, the required contribution can generally be calculated as follows:

Contribution =

1. forecast costs of augmentation (if any) of shared network assets
   minus
2. the value of this work that meets NFIT
   plus
3. full cost of new assets used only in the connection of the customer.

2.4.2 Applications and Queuing Policy

We progress connection applications and make access offers in accordance with the Applications and Queuing

[12] Section 6.19 details identified network limitations and NCS opportunities.

[13] http://www.erawa.com.au/cproot/8270/2/20100119%20AA2%20Appendix%203%20-%20Contributions_Policy.pdf

Policy (AQP)[14] as approved by the ERA as part of our Access Arrangement.

The AQP underpins and regulates the connection process, which is designed to progress customers along a pathway consisting of several milestones. These milestones provide the customer opportunities to review their connection requirements, monitor project costs as they mature and make informed decisions on how they wish to progress. The end result of the connection process is that we can make Access Offers to connect customers to the Western Power network.

The AQP contains a construct (a Competing Applications Group, or CAG) that groups applicants behind common network constraints to assess and tailor joint network access solutions. This approach provides the opportunity for competing applicants to share costs for solutions to remove (or reduce) the impeding network constraints. The AQP also allows applicants to proceed on an individual basis (via an Applicant Specific Solution), if preferred.

For each application, technical studies determine:

1. the network impact of the connection of the generator or load, and the level of reinforcement, if required
2. compliance with the Technical Rules.

In addition to understanding the AQP, potential generators and loads should be aware of their obligations under the Technical Rules[15] governing connection to the Western Power network.

2.5 Safety, health and environment

2.5.1 Objectives

In planning, constructing and operating its network, we consider safety, health and environmental (SHE) legislative requirements to manage risks to our workforce, the community and the environment.

We comply with relevant SHE legislation by establishing requirements and assurance activities in our Safety, Health and Environment Management System.

2.5.1.1 Public impact and workforce safety

We seek to satisfy the requirements of the *Occupational Safety and Health Act 1984 and Regulations 1996* to comply with the relevant occupational health and safety Codes of Practice and Australian Standards (administered by Worksafe WA and Energy Safety).

Public impact

We design and operate our network to relevant Australian safety standards and manage third-party work and development near our network to ensure that safety risks to the community are managed.

We are improving our mitigation of public impacts by establishing new requirements and assurance activities within the Safety, Health and Environment Management System and updating our internal Network Standards for the design of the network. We are also improving our management of third-party applications and referrals regarding works and proposed developments in proximity to planned and/or existing operational network infrastructure. This incorporates engagement with the planning and development industry, through forums and integration with the Western Australian town planning system (administered under the Planning and Development Act 2005). This engagement seeks to achieve safe design, controls and work practices prior to the execution of any third-party works near the network.

Workforce safety

By designing our network to relevant Australian Standards, we manage our duty of care to provide a work environment in which employees and contracting partners are not, as far as is reasonably practicable, exposed to danger. The communication of health and safety requirements through the Safety, Health and Environment Management System and Work Practices Manuals enables our operational workforce and contracting partners to take reasonable steps to care for their own safety and health while operating and maintaining the network.

2.5.1.2 Environmental management

Environmental impact assessment in Western Australia is regulated by environmental legislation, including (but not limited to):

» *Western Australian Environmental Protection Act 1986 (EP Act)*
» *Commonwealth Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act)*
» *Wildlife Conservation Act 1950*
» *Biosecurity and Agriculture Management Act 2007*
» *Contaminated Sites Act 2003*
» *Dangerous Goods Safety Act 2004*
» *Swan and Canning River Management Act 2006.*

Before commencing any construction and maintenance activities with environmental impact potential, we must obtain all necessary approvals from relevant authorities and confirm compliance with legislative obligations, by:

» quantifying the potential environmental impacts of a proposed project or activity
» demonstrating that the risk of environmental impact has been reduced as far as is reasonably practicable
» developing avoidance, management, mitigation and offset strategies for the project.

2.5.1.3 Land access

We endeavour to notify all landowners and operators of property containing our network infrastructure when access is required to construct and/or maintain our infrastructure. All reasonable efforts are made to avoid damage to land and minimise disturbance to landowner activities while accessing land. This approach is consistent with land access obligations under the Energy Operators (Powers) Act 1979.

2.5.1.4 Statutory approvals

Statutory approvals under relevant legislation may be required prior to any construction or maintenance network activity works located:

» on zoned land within a regional planning scheme (development approval required under the Planning and Development Act 2005)
» within access roads controlled by Main Roads WA under the Main Roads Act 1930
» within a rail reserve typically managed by the Public Transport Authority or Brookfield Rail under the Rail Safety Act 2010
» within the jurisdiction of the Swan River Trust.

Exemptions to the above may apply in certain circumstances. We may also be required to obtain approval or consult with other utilities and asset owners (such as the Water Corporation and Main Roads WA) if works occur in close proximity to their assets, or if the development itself will impact the future operation of their asset.

These statutory approvals are intended to address safety, land access, operational and/or community requirements relevant to the reservation areas.

2.5.1.5 Heritage approvals

We are conscious of our obligations to preserve and protect Western Australia's heritage in conducting our network operations and ensuring it meets the requirements of the State's heritage laws, including:

» *Aboriginal Heritage Act 1972*
» *Native Title Act 1993*
» *Heritage of Western Australia Act 1990.*

We minimise heritage impacts by ensuring that the relevant legislative requirements are satisfied and appropriate consultation is undertaken with relevant custodians.

[14] https://www.westernpower.com.au/media/1428/application-queuing-policy.pdf
[15] https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/technical-rules

2.6 Stakeholder and community engagement

2.6.1 Approach

We take a structured approach to our engagement with the local communities in which we operate, and our corporate values are reflected in all of our community engagement activities.

To align our performance with customer and community expectations, we create opportunities to both improve our awareness of community needs and foster a better stakeholder understanding of our operating environment.

We have adopted the core values of the International Association for Public Participation to guide our community engagement activities. We actively seek community and stakeholder input on future project and planning options, supported by the systems, processes and people that deliver them.

We are committed to early stakeholder engagement on major infrastructure projects to inform decision-making and infrastructure design processes. This also ensures that our assessment of technical options considers the community's current and anticipated needs.

2.6.2 Outcomes

Our community initiatives in 2015/16 included:

- Identification of and participation in targeted public events to reach a diverse range of community members
- Regional forums to provide communities with information on local works and an opportunity to express their concerns directly to us
- Education forums for community and industry on public safety around the network, vegetation management, land access and bushfire and storm preparedness
- Regular meetings with local government representatives across the network to address their concerns in a timely manner and discuss our strategic intent
- Visits to State and Federal MPs to understand the concerns of their electorates.

2.6.3 Network Capacity Mapping Tool

The Network Capacity Mapping Tool (NCMT) presents detailed network planning information through a geospatial map viewer. It is freely accessible from our website.[16] Introduced in 2011, it has proven popular with a wide range of user groups and surpassed our usage and site visitor expectations.

We developed the NCMT in collaboration with the Department of Planning and the Western Australian Planning Commission. The result of this collaborative effort was the first of its type in Australia, presenting infrastructure and planning information from multiple agencies through a common geospatial view.

It provides greater transparency of the existing electricity network and network expansion plans and was driven, in part, by stakeholder requests for more detailed network planning information.

By displaying our existing network and proposed augmentations, the NCMT highlights the interplay between a range of factors, contributing to more informed development plans. Users can create the precise view for their needs by selecting "layers" corresponding to the information of interest.

Updated annually to maintain consistency with the current APR, the NCMT currently provides the following information about the Western Power network:

- forecast remaining capacity for each zone substation (excluding any applicable upstream network supply constraints)
- locations of existing zone substations, terminals and most power stations
- indicative location and likely year of commissioning for committed future zone substations and terminals
- reference details to the current APR to obtain information about approved network projects for each existing and committed future Western Power zone substations
- reference details to the current APR to obtain information about specific supply issues for each zone substation's supply area
- high voltage overhead transmission lines indicating operating voltage

[16] https://www.westernpower.com.au/technical-information/calculators-tools/network-capacity-mapping-tool/ (this page also contains a short introductory video on the NCMT).

- reference links to details associated with current Western Power approved projects and scheduled community engagement sessions
- a snapshot of the overhead and underground high voltage distribution feeder reticulation, including the number of phases
- potential distribution connection points for generators to the Western Power network, shown for four capacity bands.

Although some customer-specific information is not displayed for confidentiality reasons, the NCMT presents ample detail for developers and investors at the early stages of decision-making. In some cases, additional information may be requested, such as transmission network loading information and power system modelling information[17].

2.7 Current state of the network

The Western Power network supplied a record system peak demand of 3,906 MW on 8 February 2016. This was an increase of 212 MW over the previous peak demand of 3,694 MW reached in the summer of 2011/12.

Section 6 identifies a number of areas of the Western Power network that are currently constrained, in which all new loads and load increases which do not satisfy the organic load growth criteria are subject to a more detailed assessment of connection requirements. In some cases, this may result in additional connection requirements such as a requirement for network augmentation or mitigation measures, the user's agreement to be curtailed under certain conditions, or a requirement to procure adequate Network Control Services (NCS). The non-competing criteria is subject to review to ensure that it continues to provide an appropriate mechanism for determining how costs are allocated to network users (see section 6.19 for details).

To date, the development of the Western Power network has been managed prudently to minimise the requirement for the construction of new lines, terminals, substations and circuits in order to reduce capital costs. This is particularly important in a time of rapid technological change and changing customer expectations of the network.

One of the outcomes of this approach is the high level of meshing between the 330 kV and 132 kV networks, with a heavy reliance on the 132 kV transmission lines to transfer power directly from generation, in parallel with the 330 kV bulk system. In some areas, this can result in:

- overloading of the meshed 132 kV network under contingency conditions
- insufficient reactive support at 132 kV levels under contingency conditions
- increased 132 kV line losses and high 132 kV fault levels.

There are also significant difficulties controlling 132 kV power flows to avoid post-contingent overloading of some 132 kV circuits. This creates system operability challenges, such as planning network outages for operational activities (e.g. maintenance) without interrupting supply to customers.

However, much of the existing ageing asset base is either approaching its design life or has already exceeded it. We remain committed to working collaboratively with Government, regulators and stakeholders to apply a risk-based investment program to ensure capital expenditure is targeted to manage public safety and system reliability optimally.

2.8 Future network strategy

We have developed a long-term view of the strategic development of the network and the ongoing need to effectively manage assets to the full extent of their useful lives. Sections 6 and 7 discuss the issues associated with the transmission and distribution networks and describe potential strategies for optimising their utilisation.

The objective of network planning is to develop, over a reasonable period, a highly efficient electricity network that presents the optimal balance between performance and cost. One of the key requirements to meeting this objective is improving load sharing among existing 330 kV and 132 kV assets to relieve congestion at 132 kV, particularly through the increased utilisation of 330 kV infrastructure. Key considerations in planning the network are listed below.

[17] https://www.westernpower.com.au/support/sharing-computer-models-with-third-parties/

Power flow controllability
The current network is heavily meshed with multiple parallel 330 kV and 132 kV paths. This creates limitations in controlling power flow from an operational perspective, particularly under peak demand conditions. Planning will consider options to address this, such as creating open points in the network. Proposed solutions will consider the need for operational flexibility under post-contingent conditions, including "black start" requirements (the process of returning a generator to operation when there is no network supply).

Ageing infrastructure
Some areas of the Western Power network contain assets that are more than 60 years old. For example, our planning considers the need for staged replacement and upgrade of aged 66 kV assets to 132 kV, to support load growth with minimal additional or a smaller footprint. This also removes one transmission voltage level in the area, resulting in improved backup supply options, fewer spares and increased flexibility for future reinforcement, while avoiding the need for 66 kV transformation costs. We seek to plan and make investment decisions that take into account both short and long-term outcomes, based on evaluating the whole of lifecycle cost of creating, owning, operating, maintaining and disposing of assets. This principle applies to all drivers for investment, including asset replacement, maintenance and growth.

New generation location
Lead times associated with transmission development can often exceed those required for generation construction and commissioning. Planning considers the likely connection and location of future generation plant under a range of scenarios, to facilitate the timely connection of new entrants. Further information is provided in Sections 4 and 6.

Fault level considerations
Numerous locations within the Western Power network are now approaching fault level limitations and in some cases, operational mitigations are already in place to avoid protection risks. These operational procedures can reduce network reliability or limit the maximum supportable demand by constraining generation, therefore potentially affecting the least-cost generation dispatch and unduly influencing market operation.

Connection of new large loads
The transmission network should not impede State economic growth through an inability to supply power to new large customer loads. Given the lead times associated with transmission development, Western Power regularly engages with stakeholders regarding the potential commitment of new loads and their influence on planning of the transmission system. We balance the needs of existing and new customers to prevent stranded investments due to the uncertainty of new load connections. Further information is provided in Section 6.

Network support from local generators or demand management
Load-constrained parts of the network may benefit from network support that can be provided by locating generation capacity or demand management capacity in the "catchment area" (supply area) of the load constraint. Further information is provided in Section 6.

Operational and market-related issues
A clear understanding of other operational and market issues that relate to the development of the network is important. Where applicable, solutions to these issues also feature in the Network Development Plan (NDP) cost/benefit option analysis.

Emerging technologies
We acknowledge the Western Australian electricity industry is facing a changing mix of generation, storage and consumption. We continue to keep abreast of changing technology, consumer behaviour and environment, considering these in our network planning. Further information is provided in Section 8.

These strategic considerations are used in developing the longer term plan as a means of guiding the selection of alternative projects to address a particular need. However, simple alignment with these strategic considerations is insufficient for us to commit to any particular project and does not replace the detailed power system studies and economic comparison of options that are performed within detailed business planning processes.

3. DEMAND FORECASTS

Electricity consumption and peak demand drive the level of investment in our network to deliver a safe, reliable and efficient supply of electricity to our customers.

We forecast both demand and annual peak demand every year to assist with our planning processes.

This section of the Annual Planning Report presents our latest forecast of annual peak demand. Each year we provide a new 10 year forecast. This forecast supersedes previous forecasts in our planning. In addition, we have provided insight into the key drivers of demand, our methodology and how the outlook is different as a result of our continuous improvement initiatives.

3.1 Annual peak demand forecast: 2016/17 to 2025/26

The 2015/16 central PoE 50 annual peak demand forecast for the Western Power network predicts a compound annual growth rate (CAGR) of 0.5 per cent from 2016/17 to 2025/26 (inclusive). This growth is lower than compared to the 3.8 per cent growth in the 1979/80 to 2015/16 period, yet higher than we predicted last financial year (0.3 per cent). The 2016/17 central PoE 50 peak demand forecast is approximately 2 per cent lower than the actual recorded peak in 2015/16. The 2015/16 summer was particularly hot and we do not expect a repetition of such unusual conditions in the near future.

Glossary of key terms

Demand	The amount of electricity consumed at any given time. This is expressed in units of power, usually megawatts (MW).
Annual peak demand	The highest average electricity consumption in any five minute interval during the course of one year, usually expressed in MW.
Annual average demand	Average electricity demand over the course of one year, usually expressed in MW. In this discussion, annual average demand refers to the annual average measured at five minute intervals. This is equivalent to the average annual volume of electricity consumed.

PoE	Probability of Exceedance. This is the percentage of time that an actual value will exceed the forecast value e.g. a PoE 10 forecast is expected to be exceeded 10 per cent of the time i.e. one year in ten; and a PoE 20 forecast, one year in five.
Load	Customers' electrical power and energy requirements.
Load factor	The ratio of annual average demand to annual peak demand. This is a partial indicator of network utilisation.[19]
Heatwave	The Bureau of Meteorology defines a heat wave as three or more consecutive days with maximum temperatures of 35°C or higher.

[19] Load factor is not a precise measure and can vary across different areas of the network. A trend of decreasing load factor is generally consistent with lower network utilisation, assuming a constant relationship between network capacity and annual peak demand.

This result reflects the overall combined effect of expected new block loads, continued growth in several substation zones and compensates for the temperature response demonstrated in the 2015/16 actual. Key positive growth components include:

» a number of expansion projects expected to impact substations supplying the Kwinana industrial area over the next year
» numerous urban development projects expected to maintain demand growth observed on substations supplying the coastal region between Baldivis and Margaret River - particularly the area around Mandurah and Meadow Springs, and the area between Bunbury and Busselton.

Compared to the 2014/15 forecast, the central PoE 10 Western Power network forecast for 2016/17 has been revised from 3,962 MW to 4,071 MW (i.e. +109 MW). The corresponding forecast change for 2025/26 has been revised from 4,134 MW to 4,230 MW (i.e. +96 MW). This represents an average increase for the forecast period of 2.6 per cent.

3.1.1 Key drivers of annual peak demand growth

The following three key drivers of annual peak demand growth are identified in our current forecasting process:

Underlying growth trend at each substation

This growth component reflects the consistent stable longer term trend within a geographic area supplied by a substation. It is derived through the application of appropriate econometric techniques and indicators such as:

» population growth
» growth in State and regional economic activity
» electricity price changes, cooling and heating degree days
» appliance and technology improvements resulting in reduced energy consumption
» growing solar PV penetration in the distribution network.

Table 1: Western Power network annual peak demand forecast - 2016/17 to 2025/26 (MW)

Financial year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2015/16										
Central PoE 50 Distribution Load Forecast	3,394	3,407	3,414	3,428	3,434	3,453	3,477	3,503	3,531	3,558
Central PoE 50 Western Power network Load Forecast	3,819	3,832	3,839	3,852	3,859	3,878	3,902	3,928	3,955	3,983
Central PoE 10 Western Power network Load Forecast	4,071	4,083	4,085	4,099	4,106	4,125	4,148	4,175	4,202	4,230
Change from 2014/15 forecast										
Central PoE 50 Distribution Load Forecast	139	154	166	159	160	171	173	177	181	187
Central PoE 50 Western Power network Load Forecast	112	127	139	132	133	144	146	150	154	160
Central PoE 10 Western Power network Load Forecast	109	117	120	107	102	107	103	100	97	96

Block loads at each substation

This is the increase in peak demand expected from major block loads. For each substation, timing and a degree of certainty for the block load to occur are determined. Based on the degree of certainty, three forecast load growth scenarios, Low, Central and High are produced.

For example, a block load with a determined certainty of between 67 per cent and 100 per cent is highly likely to proceed and will be added to the low forecast scenario for the substation; a determined certainty of between 33 per cent and 67 per cent will go in the central forecast scenario; and a determined certainty of between 0 per cent and 33 per cent will go in the high forecast scenario.

To ensure a consistent and systematic treatment of anticipated block loads, we have developed a block load forecast framework to determine the certainty and timing of each of them.[19] This framework provides a clear and consistent method for determining and allocating new block loads across our low, central and high forecasts.

Variability in annual peak demand due to the effect of high temperature and other factors

To cater for this effect, we develop PoE forecasts by examining the volatility of peak demand. This approach captures probable variability due to a range of factors, including the likely timing and peak demand impact of extreme temperature events, such as heatwaves.

3.2 Annual peak demand – Forecasting method

We review our 10-year annual peak demand forecasts each year to ensure:

» changes in trends are identified in a timely manner
» risks in year-to-year load variations are assessed carefully
» efficient network expansion plans are developed.

About the network hierarchy

We develop annual peak demand forecasts for the Western Power network (i.e. that portion of the SWIS we own and operate). The forecasts exclude:

» transmission and distribution network losses
» loads supplied from the SWIS but not connected to the Western Power network.

Approach to forecasting

Annual peak demand is forecast at zone substation level and then summed to produce the Western Power network peak demand forecast. This bottom-up approach ensures there is sufficient geographic resolution of the forecast annual peak demand for network capacity planning purposes.

Two peak demand forecasts are developed for each zone substation:

1. non-coincident annual peak demand
2. coincident annual peak demand.

Non-coincident zone substation forecasts indicate likely annual peak demand for each zone substation. Coincident peak demand forecasts indicate the likely demand at each zone substation recorded at the time of the SWIS annual peak demand.

The difference in coincident and non-coincident peak demand provides an indication of geographic diversity in peak demand across the Western Power network.

The non-coincident zone substation peak demand forecasts identify peak demand and growth at a detailed geographical level, allowing both distribution and transmission capacity planning to cater for expected developments at a suburb, shire or regional level.

In some cases, the non-coincident annual peak demand recorded on a given zone substation is much higher than the demand recorded on the substation, at the time of the coincident SWIS annual peak demand.

Since the early 1990s, coincident peak demand on the Western Power network has occurred during summer i.e. the annual summer peak demand has consistently exceeded the winter peak demand. A key contributor to this has been the increased use of air conditioners, which tend to increase the magnitude of peak demand during periods of extreme temperature, relative to average demand.

Forecast method

Changes in our forecasting methodology implemented for the 2013/14 forecast year have yielded a

[19] Section 4.2.1.1 of the 2012 APR presents a detailed description of Western Power's block load framework: http://www.westernpower.com.au/documents/apr_2012_web.pdf

significant improvement in forecast accuracy (discussed further in Appendix E). These changes are designed to:

» more closely track the non-linear trajectory of peak demand growth
» better separate the underlying trend from year-to-year volatility
» break down the aggregate trend growth into components that can be attributed to specific indicators (e.g. population growth, changes in economic activity, changes in consumer preferences, changes in and the adoption of technology, and changes in electricity prices and energy efficiency).

Trend growth has fallen to a low annual rate, which makes separating trend from volatile movements in peak demand (due largely to extremes in temperature variation) more challenging. For example, annual growth in customer numbers combined with the high adoption rate of reverse cycle air-conditioning indicated that temperature spikes in demand are likely to grow over time and annual volatility will remain.

For our latest (2015/16) central PoE 50 coincident forecast, the calculated volatility range due to temperature response is +250 MW. This equates to about 6.4 per cent of the PoE 50 forecast values for the period 2016/17 to 2025/26 and is represented by our 2015/16 central PoE 10 coincidental forecast.

The change in forecasting method has confirmed the historical evidence and our view that the deceleration in trend growth has stabilised. Should trend growth begin to accelerate again, more advanced forecasting methods will permit earlier detection of this change than a simple linear extrapolation method.

Treatment of block loads and transfers

A block load is one that results in a load increase that exceeds the demonstrated underlying growth trend calculated for each respective substation.

A critical element in the new forecasting methodology is the correct treatment of load transfers and block loads to ensure they are reflected accurately in underlying trends. This considers historical and future load transfers between substations and the impact of past and future block loads. These refinements ensure that the underlying trend forecast is not distorted by irregular step changes in demand. Load transfers and block loads are then added back to the forecast trend to produce the composite forecasts.

3.3 Demand changes in 2015/16

Review of previous forecasts

Reviewing the performance of the previous year's forecast is an integral part of the annual forecast cycle. This begins with a thorough assessment of the previous summer's forecast to understand the key drivers of variations in peak demand and trends (see Sections 8.4.9, Appendix E, 8.4.10 and 8.5).

Following this assessment, Western Power conducts a detailed review of block loads, comparing the actual load demand of recently-connected block loads against forecast. Forecast block loads are also carefully reassessed in consultation with stakeholders to identify changes to underlying assumptions. Any identified block load changes are incorporated in the new forecasts.

As shown in Tables 2 and Table 3 the following changes in annual peak demand and annual average demand were observed in 2015/16:

» Western Power network's annual peak demand was 194 MW above the corresponding Central 50 per cent PoE forecast.
» Annual peak demand in 2015/16, as measured at SWIS, Western Power network and Distribution Network levels, exceeded 2014/15 annual peak demand values. This was due primarily to a five-day heatwave that impacted much of the south-western landmass over the period 7-11 February 2016. Maximum temperature during this heatwave was not as extreme as seen during the 2014/15[20] summer but persisted over a longer time period than any other heatwave recorded in the last five summers. As a result, all-time record peak demand was recorded in 2015/16 at the SWIS, Western Power network and Distribution Network levels, exceeding the previous records set during the 2011/12 summer[21]. The impact of weather on the 2015/16 load demand is discussed in Appendix E.

[20] The 2014/15 summer recorded a maximum of 44.4°C on 5 January, 2015 for Perth. This is Perth's third hottest January day on record and its sixth hottest day overall.
[21] The previous annual peak demand record was in 2011/12: values for the SWIS, Western Power network and the distribution network were 4,054 MW, 3,694 MW and 3,381 MW respectively. The corresponding previous SWIS instantaneous record was 4,068 MW. The instantaneous 2015/16 SWIS annual peak demand set a new record and was 4,304 MW.

Annual average demand in 2015/16 also exceeded 2014/15 average demand as measured at the Western Power network, Distribution Network and SWIS levels.

The historical compound annual growth rate (CAGR) in annual peak demand for the Western Power network from 1979/80 - 2015/16 (inclusive) was 3.8 per cent. As shown in Table 4, the trend growth rate of the last four years has slowed to 1.4 per cent following three successive four-year periods of moderate but declining growth. This is faster than the five year average reported in the 2014/15 APR, the increase being a result of the extraordinary increase in peak demand recorded in 2015/16.

The decelerating trend growth reflects a range of changes in structural factors, such as:

» a 73 per cent increase in scale (i.e. a given increase in MW in 2015/16 corresponds to a smaller percentage increase than it would have in 1999/2000)
» changes in technology, which tend toward increasing energy conservation over time
» changing consumer preferences, particularly the continued take-up of self-generation via solar PV.

Note: Trend growth for the three year period 2011/12 – 2014/15 is -0.8 per cent. It is the 2014/15 to 2015/16 change in annual peak demand (301 MW or 8.35 per cent) that is responsible for the exaggerated growth rate in this later four year period. Appendix E discusses the reasons behind this change.

Table 2: Change in annual peak demand - 2014/15 to 2015/16 (MW)

	2015/16	Change from 2014/15
SWIS	4,286	6.30%
Western Power network	3,906	8.35%
Distribution Network	3,515	10.67%

Table 3: Change in annual average demand - 2014/15 to 2015/16 (MW)

	2015/16	Change from 2014/15
SWIS	2,301	0.96%
Western Power network	1,976	1.51%
Distribution Network	1,578	2.54%

Table 4: Summary of trend change in peak demand for the Western Power network - 1999/00 to 2015/16

FYE	1999/00 - 2003/04	2003/04 - 2007/08	2007/08 - 2011/12	2011/12 - 2015/16
CAGR	5.1%	4.1%	3.3%	1.4%

3.3.1 Independent audit and review

We periodically commission independent auditors to review our annual peak demand forecasting methods to ensure that good industry practice is applied consistently. In 2016 NIEIR[22] was commissioned to perform such a review. While favourable, NIEIR suggested changes in method that may lead to further improvement in terms of insight and forecast accuracy.

In summary, these are:

» Where suitable data is available, utilise more regional specific growth drivers (such as regional population forecasts) to better capture differences in growth pressures across the Western Power network. This is in contrast with current practice of modelling zone substation demand using State-level growth drivers.

» Instead of a bottom-up forecast method, develop a top-down forecast method that explicitly separates base demand and temperature responsive demand at the Western Power network level. A top-down forecast method facilitates more precise identification of sectoral influences on demand, and helps differentiate between regional specific trend and volatile components of demand. This could result in a change in the balance between trend growth and risk estimates at the zone substation level.

We are in the process of assessing NIEIR's recommendations with a view to implementing those that will improve our current forecasting methods, and ultimately most benefit the business.

[22] NIEIR (National Institute of Economic and Industry Research)

4. GENERATION SCENARIO PLANNING

Under present arrangements in the SWIS, the standard form connection agreement for large generators (Electricity Transfer Access Contract or ETAC) provides generators with unconstrained access rights to the Western Power network. This is commonly referred to as a 'reference service'.

4.1 Generation connection arrangement

Under the current unconstrained access regime, Western Power undertakes generation planning with consideration to the access rights of existing users with 'reference services'.

Where the assessment identifies a need to reinforce the network to preserve those access rights, and the cost of that reinforcement is uneconomic, we seek to collaborate with the user and other stakeholders, to identify alternative options to facilitate the timely and economic connection to the SWIS. Technical studies are also undertaken to assess the impact on other aspects of system performance, such as network fault levels and power system transfer limits. Accurate computer modelling information forms a vital component of the assessment undertaken by Western Power.[23]

4.2 Use of scenarios in transmission planning

Western Power periodically refreshes the generation development scenarios in the Annual Planning Report. This informs customers about assumptions underlying our projections of emerging limitations on the transmission network. Developing generation scenarios can be a complex process. It relies on a number of assumptions about the location of new generation based on an understanding of likely new generation sites, expansion plans of incumbent generators and the planning directions of government policy.

We seek to align our network development plans with generation development scenarios, to anticipate future network capacity requirements, and optimise investment plans. Scenario planning also helps align network augmentation and customer project development timelines.

The generator connection process is governed by the Applications and Queuing Policy. Under revisions to this policy introduced in our third Access Arrangement, connection applications are aggregated into Competing Applications Groups, with connection solutions developed for each group. Connection applicants may pursue an Applicant Specific Solution.

4.3 Generation scenario development

The current Wholesale Electricity Market features an oversupply of generation and stagnant demand growth forecasts. In present conditions, the Australian Energy Market Operator (AEMO) has not identified a need for new generation capacity[24].

However, Western Power recognises that that the Federal Government's

[23] https://www.westernpower.com.au/media/1888/generator-and-load-model-guidelines-20160511.pdf

[24] Deferred 2015 Electricity Statement of Opportunities for the WEM

Renewable Energy Target (RET) is likely to provide incentive for connection of renewable generation in the short-to-medium term. As current legislation requires the RET trajectory to be maintained at its present level from 2020 to 2030, it is expected that the bulk of development under it will occur prior to 2020.

To analyse current electricity market conditions, we engaged independent consultants to assist with the development of several network outlooks capturing a range of possible future scenarios, with potential to affect transmission network development. These are summarised in Table 5.

Table 5: Summary of network outlooks

	Central Network Outlook	High-Growth Network Outlook	Rapid Change Network Outlook
Outlook description	Central network outlook based on our view.	Return to demand growth, including entry of electric vehicles. Climate policy remains static.	Engaged consumers and strong centralised action contribute to significant changes to the electricity market. The longer term return of carbon pricing, combined with State-based schemes, result in WA building its pro-rata share of RET generation. Aging capacity is retired.
Peak demand	Based on the central scenario load forecast in the 2014-15 Annual Planning Report.	Based on the expected case load forecast in IMO's 2014 Statement of Opportunities.	Assumed lower load forecast due to improved energy efficiency.
Electric vehicles (EV)	Few EVs.	High growth in EVs from 2020. Engaged consumers charge vehicles predominantly overnight and during midday solar peaks, limiting impact on peak demand.	Moderate growth in EVs from 2020. Engaged consumers charge vehicles predominantly overnight and during midday solar peaks, limiting impact on peak demand.
Rooftop PV	As per demand forecast.	As for demand forecast.	Higher PV penetration, but contribution is limited to peak demand reduction.
Battery storage	No significant large scale or domestic battery storage.	As for Central Network Outlook.	As for Central Network Outlook.

Table 5: Summary of network outlooks (continued)

	Central Network Outlook	High-Growth Network Outlook	Rapid Change Network Outlook
Demand management (DM)	Existing DM providers.	As for Central Network Outlook.	Additional 50 MW of DM by 2020.
Thermal generation retirements	Retirement of Kwinana C units.	As for Central Network Outlook.	Moderate retirement of units.
Gas price	Based on AEMO's modelling of international gas price.	Lower than Central Network Outlook.	As per Central Network Outlook.
RET and renewable development	33000 GWh by 2020. No State-based WA schemes or incentives for renewable generation. WA builds less than pro-rata share of RET generation.	As for Central Network Outlook.	Higher share of renewables in WA, driven by State-based incentives. WA builds pro-rata share of RET generation, based on regional energy.
Emissions reduction ambition	No carbon price. No State-based WA emissions reduction schemes. No mandated retirement of thermal capacity.	As for Central Network Outlook.	Carbon price returns in 2020 at $30 per tonne CO2e.
Technology cost	Derived from Australian Energy Technology Assessment[26] and 2014 National Transmission Network Development Plan[27] data.	As for Central Network Outlook.	Lower capital costs for renewable technologies.

Even within a particular network outlook, there is uncertainty regarding the way that investors and market participants will respond to external market, economic and regulatory drivers. Therefore, multiple generation planting schedules may be developed for each network outlook. The two most likely generation scenarios based on our view of the network outlooks are shown in Table 6. These generation planting scenarios are used to identify existing and emerging limitations in the transmission system and are periodically refreshed.[2526]

[25] http://www.industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-technology-assessments.aspx
[26] http://www.aemo.com.au/Electricity/Planning/Archive-of-previous-Planning-reports/~/media/Files/Electricity/Planning/Reports/NTNDP/2014/NTNDP%202014%20%20main%20document.ashx

Table 6 : Generation planting for the two most likely scenarios

Year	Generation Planting Schedule A	Generation Planting Schedule B
2015/16	Biomass South 40 MW Retired Metro 361 MW Retired Metro 123MW	Retired Metro 361 MW Retired Metro 123MW
2016/17	None	None
2017/18	Wind North 130 MW Solar North 30 MW Biomass Metro 30 MW	Solar North 30 MW
2018/19	Wind North 50 MW Wind South 50 MW	Wind South 40 MW Solar Metro 30 MW Wind North 130 MW
2019/20	Solar Metro 30 MW	Biomass South 40 MW Solar North 20 MW
2020/21	None	None
2021/22	None	None
2022/23	None	None
2023/24	None	None

5. COMPLETED PROJECTS

This section describes augmentations completed in the period between the publication of the 2015/16 APR and 31 December 2016.

The tables in this section list projects completed up to 31 December 2016. These projects respond mainly to the drivers of load growth and new connections, but also include asset condition drivers relating to substation power transformers, transmission lines and switchboards. The key benefit delivered by each project is also listed.

Table 7: Completed projects - zone substation augmentations 1 July 2015 - 31 December 2016 (18 months)

Project	Benefit/s
Joel Terrace: substation reinforcement – conversion to 132 kV	Mitigate safety and reliability risks associated with the failure of 66 kV and 11 kV assets that are in degraded condition.
Refurbish switchboard at Mason Road substation	Address degraded asset condition.
Installation of a third 132-66/11 kV transformer at the new Medical Centre substation	Accommodate the remaining load from the 66kV Medical Centre substation and load transfer of entire University substation load to facilitate the decommissioning of the substation.
Establish a new Shenton Park 132/11 kV substation	Accommodate increasing demand in the area; create additional feeder capacity (voltage conversion) to accommodate future peak demand and additional distribution transfer capacity. Facilitates the future decommissioning of University, Herdsman and Nedlands substations.
Address non-compliance issues on Moora substation's transformer	
Replace indoor switchboard at West Kalgoorlie substation	
Replaced failed transformer at Bunbury Harbour substation	
Decommissioning of old Medical Centre substation, following establishment of the new Medical Centre substation	Address degraded asset condition.
Installation of a new 132-66/22 kV transformer at the Margaret River Substation	
Resupply British Petroleum from Mason Road Substation	

Table 8: Completed projects - distribution feeder network augmentations 1 July 2015 - 31 December 2016 (18 months)

Project	Benefit/s
Albany: Mitigate under fault rated conductors	
Busselton: Mitigate under fault rated conductors	
Bunbury Harbour: Mitigate under fault rated conductors - Stage1	
Darlington & Hazelmere: Mitigate under fault rated conductors	Mitigate safety risk and risk of outages due to under fault rated conductor; ensure compliance with the Technical Rules in relation to fault level requirements.
Kalamunda: Mitigate under fault rated conductors	
Wagerup: Mitigate under fault rated conductors	
Wanneroo: Mitigate under fault rated conductors	
Yanchep: Mitigate under fault rated conductors	
Bridgetown: Mitigate under fault rated assets and protection reach	Mitigate safety risk and risk of outages due to under fault rated conductor; ensure compliance with the Technical Rules in relation to fault level and protection requirements.
Kondinin: Mitigate under fault rated conductors and protection reach	
Busselton: Distribution network reinforcement	Reduce feeder peak loading; improve distribution transfer capacity; reduce the risk of long duration outages in the area.
Forrest Avenue: Distribution network reinforcement	Reduce feeder peak loading; improve distribution transfer capacity; reduce the risk of long duration outages in the area.
Joel Terrace : Transfer of distribution feeders	Temporary transfers of distribution feeders between 11 kV switchboards at Joel Terrace substation to enable work on conversion from 66 kV to 132 kV to be carried out in stages.
Manning St: Network reconfiguration and install new feeders	Reduce feeder overloading; improve distribution transfer capacity; reduce the risk of long duration outages in the area.

Table 8: Completed projects - distribution feeder network augmentations (continued)

Project	Benefit/s
Medical Centre & University: Conversion of existing Medical Centre and University distribution network to 11 kV	Voltage conversion and load transfer of the 6.6 kV Medical Centre and University load to the new 132/11 kV transformers at the new Medical Centre substation. Accommodate increasing demand with voltage conversion and address assets in degraded condition.
Northam: Single phase feeder reinforcement	Creation of capacity on single phase line and catering for compliance issues
Replacement of under fault rated equipment at North Fremantle, Collier, Milligan Street, Summer Street, Wembley Downs and Western terminal substation	Mitigate fault level constraints and associated safety and reliability of supply risks associated with under fault rated equipment.
Resupply British Petroleum substation from Mason Road substation	Address degraded asset condition at British Petroleum substation. Transfer four feeders from existing British Petroleum substation to Mason Road Substation and Medina substations due to the decommissioning of British Petroleum substation.
Northam: Install Isolation Transformer (Batch 5)	Compliance issue – address protection reach, improve the feeder imbalance and the spur capacity.
South Country: Install Isolation Transformers (Priority 2)	

6. TRANSMISSION SYSTEM ISSUES AND DEVELOPMENTS

The Western Power network extends from Kalbarri in the north to Albany in the south and from the West Coast to Kalgoorlie in the east. This area covers five major regions that are divided into 15 load areas for transmission planning purposes, as shown in Figure 1.

We routinely assess the condition of transmission assets and the ability of the transmission network to supply existing and future demand growth in accordance with the Technical Rules. The rules specify the level of supply reliability and system security that must be maintained. Our routine assessments identify existing and future transmission constraints, which are typically associated with:

» thermal capability of transmission lines
» fault levels limitations
» requirement for voltage support
» asset condition.

This section describes the current supply arrangements on the transmission network, the existing constraints, those forecast to emerge over the next five years, and those which may emerge due to load or generator connection proposals. We will also discuss the conceptual transmission augmentations being considered to address transmission limitations.

6.1 Bulk transmission capacity and constraint

Since the early stages of the development of the State's modern electricity infrastructure, base load generation development has been concentrated in the south west of the system, within close proximity to major coal resources.

With comparatively little base load generation elsewhere on the system, power supplies are typically transferred from the south of the system to the major load centres to the north.

A 330 kV transmission system provides a backbone for the bulk transfer of electricity to strategic points in the network, including supply to areas north of the metropolitan region. There is currently considerable spare capacity for increased power transfer on the 330 kV network from major generation centres in the south (around Muja and Kemerton) to the Kwinana region and further north to Southern, Cannington (via Kenwick Link), Guildford, Northern and Neerabup terminals.

There is considerable flexibility for future expansion of the 330 kV network to support generation reserve sharing between the north and south of our network from the Collie area to the Neerabup area. This is due to:

» the Northern terminal to Pinjar 330 kV circuit and one of the Guildford to Northern terminal 330 kV circuits currently being energised at 132 kV

» the Southern terminal to Guildford 330 kV double circuit (currently strung on one side).[27]

In 2015, we completed the Mid West Energy Project (MWEP) Southern Section transmission line to increase the power transfer capacity to Three Springs, provide support to Geraldton and to reduce the reliance on generation at Mungarra. The project included a new 330 kV terminal at Three Springs and a double circuit 330 kV transmission structure from Pinjar to Three Springs terminal. One of the Pinjar to Three Springs terminal circuits is currently energised at 330 kV to connect Neerabup terminal to Three Springs terminal and the other circuit is energised at 132 kV to connect Pinjar to Three Springs via Eneabba. This circuit, together with the existing Northern terminal to Pinjar 330 kV circuit (which is also currently energised at 132 kV) provides an opportunity to further increase transfer capability between the northern metropolitan area and Three Springs through future operation at 330 kV. This uplift from 132 kV to 330 kV is planned to occur as part of the Mid West Energy Project Southern Section Stage 2. The timing of this project is dependent on new entrant generation and large loads connecting in the North Country area.

The bulk transmission system north of Three Springs terminal operates at 132 kV and is considered relatively weak. Constraints on power transfers currently apply under condition of high generation north of Three Springs and there are considerable ageing assets in the area. We will continue to investigate expansion of the bulk transmission system north of Three Springs as part of the MWEP Northern Section. This project would significantly improve bidirectional transfer capability north of Three Springs and the system is likely to be constructed at 330 kV, but may be operated at 132 kV for some time. Studies are underway to identify the optimised growth and asset condition timing, which is dependent on new entrant generation or large loads connecting north of Three Springs.

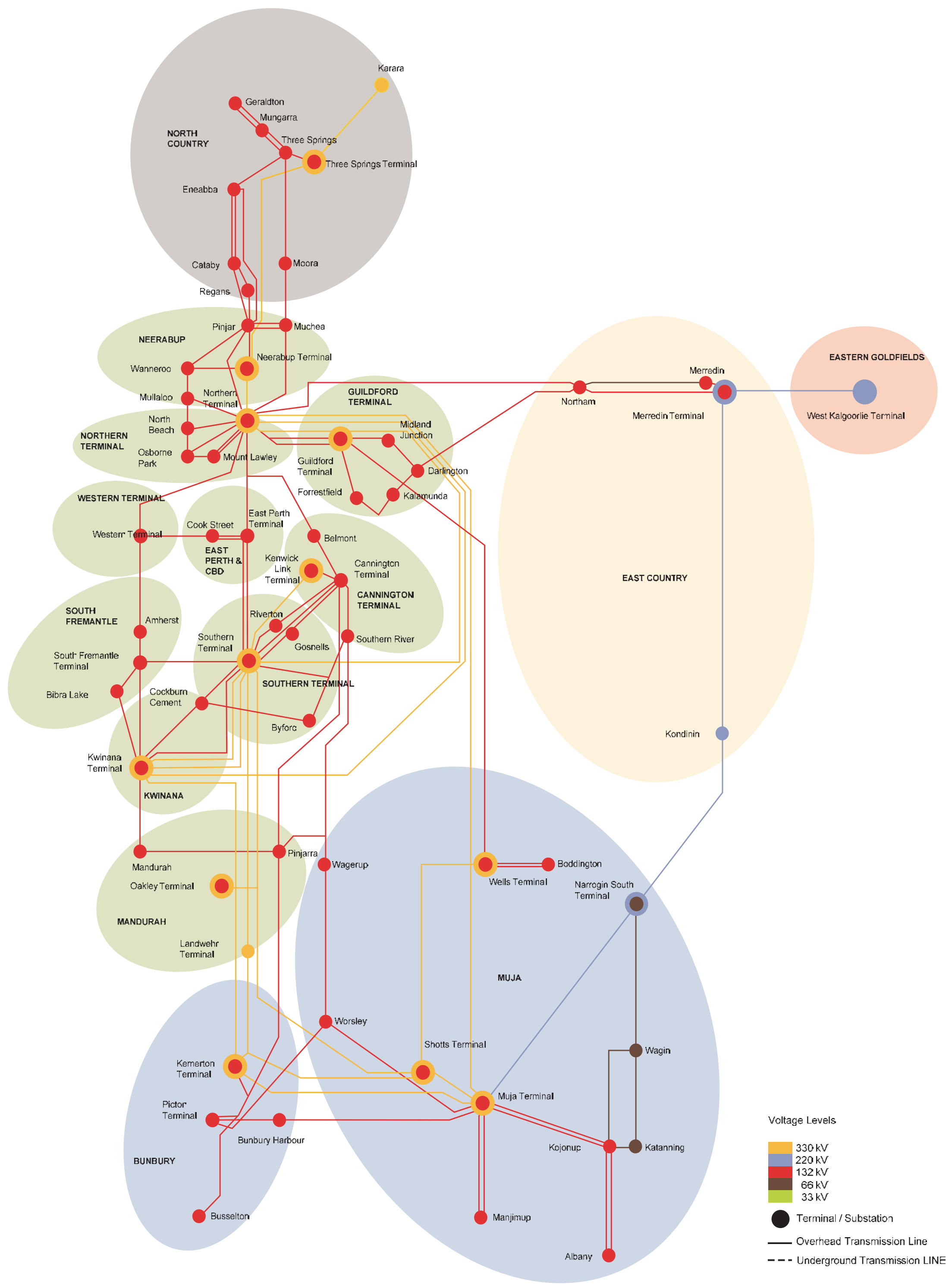
For many years, the 330 kV transmission network has been planned and operated in parallel with the underlying 132 kV network. Augmentations at 132 kV have resulted in a heavily meshed arrangement in many areas, particularly around the inner metro areas. While this was a prudent strategy at the time, it has led to heavy use of the 132 kV system and lower use of the 330 kV bulk transmission network. Under maximum demand conditions, some areas of the 132 kV network are now operating at capacity, due partly to the 132 kV network being used for bulk power transfer between major terminal sites.

The meshed nature of the network also increases fault levels at various locations, some of which are expected to exceed equipment specifications in the near future. The connection of new generation to the network will also drive increasing fault levels.

We have identified benefits associated with de-meshing the 330 kV and 132 kV transmission systems at strategic points in the network. This would improve the use of the 330 kV transmission network for bulk power transfer, while offloading the underlying 132 kV network and reducing fault levels. It is anticipated that de-meshing the networks may affect reliability of supply and operational flexibility to manage incidents and will result in a need for additional works to meet mandated obligations. The alternative to this strategy would be ongoing development of the 132 kV meshed network and installation of fault level mitigation equipment. This would result in continued underutilisation of the 330 kV transmission system and higher overall network development costs in the longer term.

[27] This is a double circuit structure for the majority of the distance, with some single circuit structures near the Guildford and Southern terminal ends. A number of additional structures are required to support a double circuit.

Figure 1: Western Power network - transmission load areas



The power transfer capacity of the network is dependent on a number of factors, including the potential for thermal overload of conductors, fault levels in excess of equipment specifications and voltage or other dynamic stability related issues. Network augmentations are necessary to ensure all plant continues to operate within its capability and the power system remains reliable and secure in accordance with the Technical Rules.

The Western Australian Wholesale Electricity Market (WEM) is administered and is now also operated by the AEMO[28]. The WEM provides the trading environment for generation and generation developers and demand-side proponents to make investment decisions taking into account forecast revenue available from the market arrangements.

As we do not direct the location of new generation, we must make prudent assumptions when modelling long-term generation scenarios in its network planning process. Generation planning scenarios provide an understanding of the likely location of emerging constraints in the future, which in turn informs the need for investment in different parts of the network. We use probabilistic generation scenario based planning techniques together with information about new entrant enquiries to inform decisions on the areas where network development is most likely required.

6.2 Local generation and demand management opportunities

As part of our usual assessment of alternative solutions, we may seek expressions of interest for the provision of Network Control Services (NCS) to provide network support. However, demand management and localised generation support proponents may equally wish to proactively anticipate load areas where connection and dispatch of energy services capacity is likely to provide network support and therefore have the potential to be facilitated by Western Power.

Sections 6.4 to 6.18 provide a summary of emerging limitations in the transmission network that arise over the five year outlook. We anticipate in some cases local generation and/or demand response capacity could potentially provide useful support to the network and defer more costly network investments. We invite any present and aspiring market participants with local generation or demand management capacity capable of alleviating any of the emerging limitations to contact us directly.

6.3 Committed works

This section describes transmission augmentation projects that have been approved and will be completed over the next five years.

Table 9 lists the committed transmission augmentation projects as at 31 December 2016. To be considered as committed, transmission augmentations must satisfy all of the following criteria:

» Ministerial approval (if required)
» Board commitment has been achieved (if required)
» funding approval
» the project has satisfied the Regulatory Test (if required)
» for augmentations required to connect a customer, that a customer has unconditionally signed an Interconnection Works Contract (IWC) with Western Power (if required)
» construction has either commenced or a firm commencement date set.

Any that do not meet all of these criteria are classified as 'proposed network projects'.

* Projects marked with an asterisk increase zone substation thermal capacity.

[28] The roles of independent energy market operator and independent power system operator in Western Australia were transferred to the Australian Energy Market Operator (AEMO) as part of the State Government's Electricity Market Review, (Market operations function took effect 30 November 2015).

Table 9: Committed works as at 31 Dec 2016

Project	Benefit/s	By when
Kwinana to Southern terminal partial de-mesh	Reduce fault levels; relieve thermal limitations.	Summer 2017/18
Resupply North Fremantle substation from adjacent substations and decommissioning of the remaining fluid-filled cable section between North Fremantle and Edmund Street	Address degraded asset condition.	Winter 2017
Install switches on Pinjarra-Kemerton-Picton-Busselton 132 kV line	Address the reliability issues during bushfire for the four ended line Pinjarra-Kemerton-Picton-Busselton 132 kV line	Summer 2016/17
Install a third 132/11 kV transformer at Rangeway substation*	Accommodate increasing demand in the area; create additional feeder capacity to allow for load growth and additional distribution transfer capacity.	Summer 2017/18
Install a third 132/22 kV transformer at Meadow Springs*	Accommodate increasing demand in the area.	Summer 2017/18
Decommission University substation following establishment of the new Medical Centre substation	Address degraded asset condition.	Summer 2017/18
Decommission the existing Shenton Park substation following establishment of the new Shenton Park substation	Address degraded asset condition.	Summer 2018/19
Partial conversion of Busselton 66 kV substation to 132 kV*	Address degraded asset condition; accommodate increasing demand in the area.	Winter 2017
Replace failed 220/132 kV bus tie transformer BTT2 at Muja terminal with a new unit	Replace a failed asset.	Summer 2017/18
Decommission Herdsman Parade substation following establishment of the new Shenton Park substation	Address degraded asset condition.	Summer 2018/19
Replace under fault rated equipment at Collier, Summer Street, Wembley Downs and Western terminal substation	Mitigate fault level constraints.	Summer 2018/19
Decommission Durlacher substation	Address degraded asset condition.	Summer 2021/22
Partial decommissioning of Nedlands substation	Address degraded asset condition.	Summer 2018/19
Install additional special protection schemes on Eastern Goldfields' transmission network	Relieve rotor angle stability issues in the area.	Summer 2017/18
Replace SVCs at West Kalgoorlie terminal	Address degraded asset condition	Summer 2020/21

6.4 North Country load area

The North Country load area extends from Pinjar and Muchea at the northern edge of the Neerabup terminal load area to Kalbarri at the northern extremity of the network. The load area extends inland approximately 150 km to service the northern Wheatbelt.

The network is approximately 400 km long, from Pinjar to Geraldton, and is largely comprised of two single circuit 132 kV lines north of Three Springs, and three 132 kV circuits to the south of Three Springs (Figure 2) and one 330 kV circuit from Neerabup terminal to Three Springs terminal. A number of generators inject at various locations within the North Country network. The network has evolved over time, primarily supplying relatively small loads distributed over a large geographical area. To ensure we can continue to provide a reliable supply to customers and facilitate future generation connections, we anticipate the North Country load area will be subject to considerable network development over the coming decade.

The MWEP Southern Section (Stage 1) was completed in early 2015. This development increases power transfer capacity to Three Springs, and provides additional support through to Geraldton, reducing reliance on Mungarra generation and facilitating future work.

New generation entrants are showing considerable interest in new renewable energy and fuel resource developments in the area. Given the volume of connection enquiries, it is anticipated that over the medium to longer term, the North Country load area is likely to serve the purpose of a generation hub and also service a growing number of larger mining load developments.

Last year the State Government directed Synergy to reduce it's generation cap and the business is doing this by retiring four generation assets[29]. This may lead to traditional coal fired and gas generation being replaced with renewable generation. With abundant renewable resources (in particular wind and solar) available, new generation proponents may be offered incentives to connect in the North Country load area.

To facilitate the connection of potential new entrant generation and block loads, we will also propose to expand the MWEP as the need arises. This staged proposal currently includes building a 330 kV terminal at Eneabba, followed by the MWEP Southern Section (Stage 2) and the MWEP Northern Section.

The MWEP Southern Section Stage 2 involves:

- energising the second side of the double circuit 330 kV line (constructed as part of Stage 1) to 330 kV
- reinforcement works at Three Springs terminal
- new 330/132 kV terminal at Eneabba and 132 kV reinforcement between Eneabba and new Eneabba terminal
- resupply of Regans substation
- 132 kV reinforcements in the Neerabup load area.

The MWEP Northern Section will increase the transfer capacity between Three Springs and Geraldton. This supports potential connection of new entrant generators and load north of Three Springs.

The timings for these projects are triggered by the connection of new load and generation customers. However, there are also strong drivers for certain stages of the project due to asset condition. The condition of numerous wood pole assets between Muchea and Geraldton will require extensive reinforcement and replacement. Investigations are underway to establish the optimal timing of certain stages of the project with consideration to revised load and generation projections, as well as long-term wood pole management costs.

6.4.1 Emerging transmission network limitations within a five year period

Generator connection applications

There are a number of connection applications being progressed in the North Country load area (see Section 6.20.2 for additional information).

Substation capacity

Load forecasts indicate that the capacity of all substations in the North Country load area is sufficient for the five year outlook.

Switchgear asset condition issues exist at the Geraldton, Moora and Three Springs substations. We are currently investigating options for optimising their replacement.

Asset condition assessments have identified that a transformer at Geraldton substation is in degraded condition. Treatment assessments have identified an opportunity to partially refurbish the transformer which is expected to defer the replacement plans beyond the five year horizon.

Durlacher substation and its associated transmission line infrastructure have been assessed as being in degraded condition and has limited capacity to support new customers. A committed project is currently in the execution phase, which involves decommissioning Durlacher substation and transferring all loads to the neighbouring Rangeway substation. In order to accommodate additional loads, a third transformer will be installed at Rangeway substation. This transformer will support expected load growth in the Geraldton area for the foreseeable future, based on current load forecasts.

Fault levels

There are no significant fault level limitations in the North Country load area at present. There are, however, numerous generation connection enquiries and fault levels are expected to increase with commissioning of new generation. Depending on the location and type of future generation, fault levels may become problematic in some areas.

Thermal limits

Following thermal overloads exist today or emerge over a five year horizon, some of which are dependent on the dispatch profile of generation in the north:

- 132 kV circuits between Three Springs and Mungarra for loss of either parallel circuit
- 132 kV Three Springs substation busbar.

Overloads on the Three Springs to Mungarra 132 kV corridor can occur under conditions of high generation north of Three Springs in the event of loss of one circuit. These constraints are managed by generation runback schemes. At present, the majority of the generation capacity connected north of Three Springs is wind turbines, apart from the Mungarra gas turbine power station, Tesla Geraldton diesel power station and the Greenough River solar farm.

With existing generation, the incidence of a Three Springs busbar overload is unlikely and would be managed operationally through generation re-dispatch, rather than reinforcement. The amount of new entrant generation north of Three Springs anticipated within the five year outlook will significantly increase the need for augmentation works.

Voltage limits

Following the completion of the MWEP Southern Section (Stage 1), power transfer capacity within the North Country load area has increased. As a result, no voltage instability issues are forecast in the area over the next five years.

[29] https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/04/Electricity-reforms-ensure-fairer-system-for-all.aspx

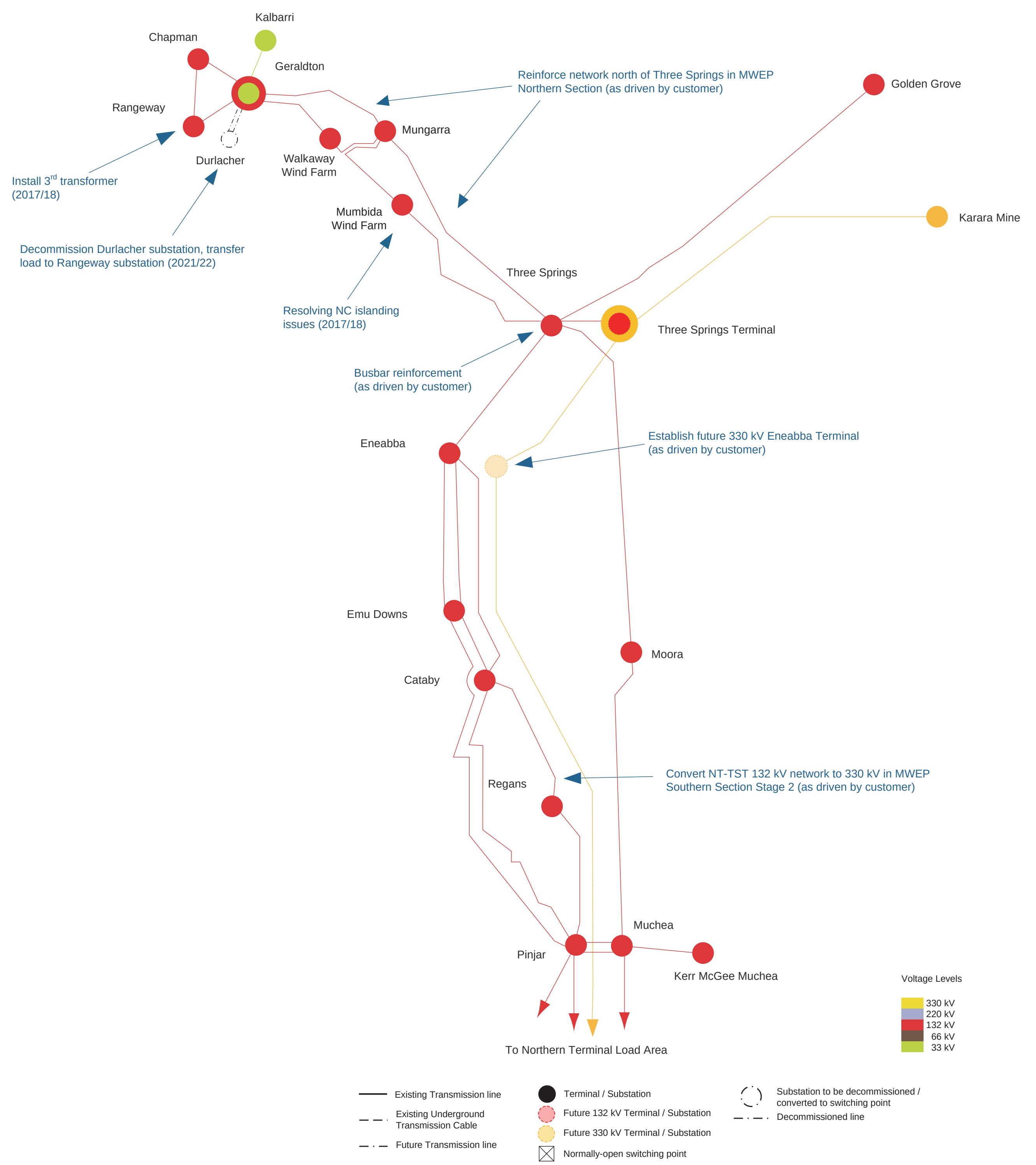
6.4.2 North Country load area transmission system development

Figure 2 shows the preferred transmission network strategy for the North Country load area, reflecting the impact of the MWEP Northern Section. Table 10 lists the expected benefits of the planned works.

Table 10: North Country load area - planned works and expected benefits

Project	Benefit/s	By when
Resolve North Country Islanding Issues	Address network islanding issues	Summer 2017/18
Install a third 132/11 kV transformer at Rangeway substation*	Accommodate increasing demand in the area; create additional feeder capacity to allow for load growth and additional distribution transfer capacity.	Summer 2017/18
Decommission Durlacher substation	Address degraded asset condition.	Summer 2021/22
Three Springs busbar reinforcement	Relieve bus bar thermal overload.	As driven by customers
Establish Eneabba 330 kV terminal	Accommodate new entrant generation connections in the North Country area.	As driven by customers
Mid West Energy Project (Southern Section Stage 2)	Accommodate increasing demand and new entrant generation connections in the North Country area; facilitate future staging of a 330 kV network north of Three Springs.	As driven by customers
Mid West Energy Project (Northern Section)	Accommodate increasing demand in the Geraldton area, as well as new entrant generation north of Three Springs.	As driven by customers

Figure 2: North Country load area - preferred transmission solutions



6.5 Eastern Goldfields load area

The Eastern Goldfields load area is centred around the City of Kalgoorlie-Boulder. The load area extends west of Kalgoorlie-Boulder to Merredin and south to Kambalda.

The network in the area supplies residential and mining loads and provides a transmission link to the rest of the network. The bulk of supply to the area comes from a long 220 kV single line to the Merredin terminal in the adjacent East Country load area. There is also a significant amount of local diesel and gas-fired generation installed at Kalgoorlie-Boulder, the bulk of which is private power producers supporting in-house mining loads.

Because of its single connection to the rest of the network, the Eastern Goldfields load area 220 kV network is operated to an N-0 standard, which reduces the level of network security.

A complicating factor in the planning of network augmentation needs in the area is the nature of the surrounding loads. These are typically block loads required to meet mining needs, which makes them difficult to forecast due to their inherent volatility in response to market economics and commodity prices. Considerable uncertainty in demand forecasts in turn creates difficulties when evaluating the need to commit to transmission system reinforcements. NCS opportunities may therefore present alternatives to network solutions, especially given the high costs associated with augmenting the transmission network reaching out to the Eastern Goldfields system.

Given its length, the transmission system to the Eastern Goldfields presents considerable operational challenges, particularly in relation to system stability. A number of special control schemes are in place to control system stability and to allow considerable amounts of the Eastern Goldfields load area to continue to have supply following separation from the rest of the Western Power network.

6.5.1 Emerging transmission network limitations within a five year period

Load connection applications

There are presently a number of load connection (and demand increase) proposals being actively progressed in the Eastern Goldfields (EGF) load area (see Section 6.19.2 for additional information).

- » limitations impacting the ability to connect new loads include:
- » thermal limitations in the East Country 132 kV network, EGF 132 kV network, and West Kalgoorlie 220/132 kV substation
- » voltage stability limitations in the EGF for faults and for load rejection events
- » synchronous stability limitations whereby gas turbine generators in the EGF lose synchronism with the main system
- » other considerations, such as impact on load rejection ancillary services, spinning reserve, and electrical losses.

Substation capacity

Load forecasts indicate that the capacity of all substations in the EGF load area is sufficient for the five year outlook.

Fault levels

No fault level issues are forecast in the Eastern Goldfields load area over the next five years.

Thermal limits

Thermal limitations are not expected to present any issues over the next five years. At present, there are voltage and stability limitations which determine the power transfer capability to the Eastern Goldfields load area. Should these voltage and stability limits be relieved in the future, thermal limitations may then become the dominant constraint.

Voltage limits

There are voltage and transient stability limitations in the Eastern Goldfields load area, which are influenced by:

- » the power output of local generators in the area
- » total power import into the Eastern Goldfields load area.

These limitations are driven, in part, by the relatively low inertia of generating units and insufficient reactive reserve. These limitations are currently managed through special control schemes and a Dispatch Support Contract operated by Australian Energy Market Operator (AEMO).

Saturated reactors at Merredin and West Kalgoorlie terminals provide dynamic reactive support in the area, in addition to local generating units. Condition assessment of these saturated reactors shows that both are deteriorating and reaching the end of their lives. A project is in execution to replace these ageing saturated reactors with STATCOM technology, whilst maintaining the power transfer limit to Eastern Goldfields by 2020/21.

Oscillatory stability issues (small signal) have also been identified between machines in the area and other SWIS generating units. We installed a dynamic power system monitoring tool (Psymetrix) to help identify oscillatory stability-related issues in the area and to improve system security.

Furthermore, due to the unavailability of fast acting anti-islanding protection, we have identified a risk of maintaining the power quality performance standards in the Eastern Goldfields (EGF) network, following a single 220 kV line contingency that results in an islanded network.

Due to the relatively low capital cost of installing protection and control schemes compared to traditional network reinforcement options in the Eastern Goldfields load area, a large number of protection and control schemes have been installed over recent years. During the replacement of secondary assets supporting these schemes, an opportunity to streamline and optimise the existing schemes has been identified which will offer increased capacity to accommodate future schemes.

6.5.2 Eastern Goldfields load area transmission system development

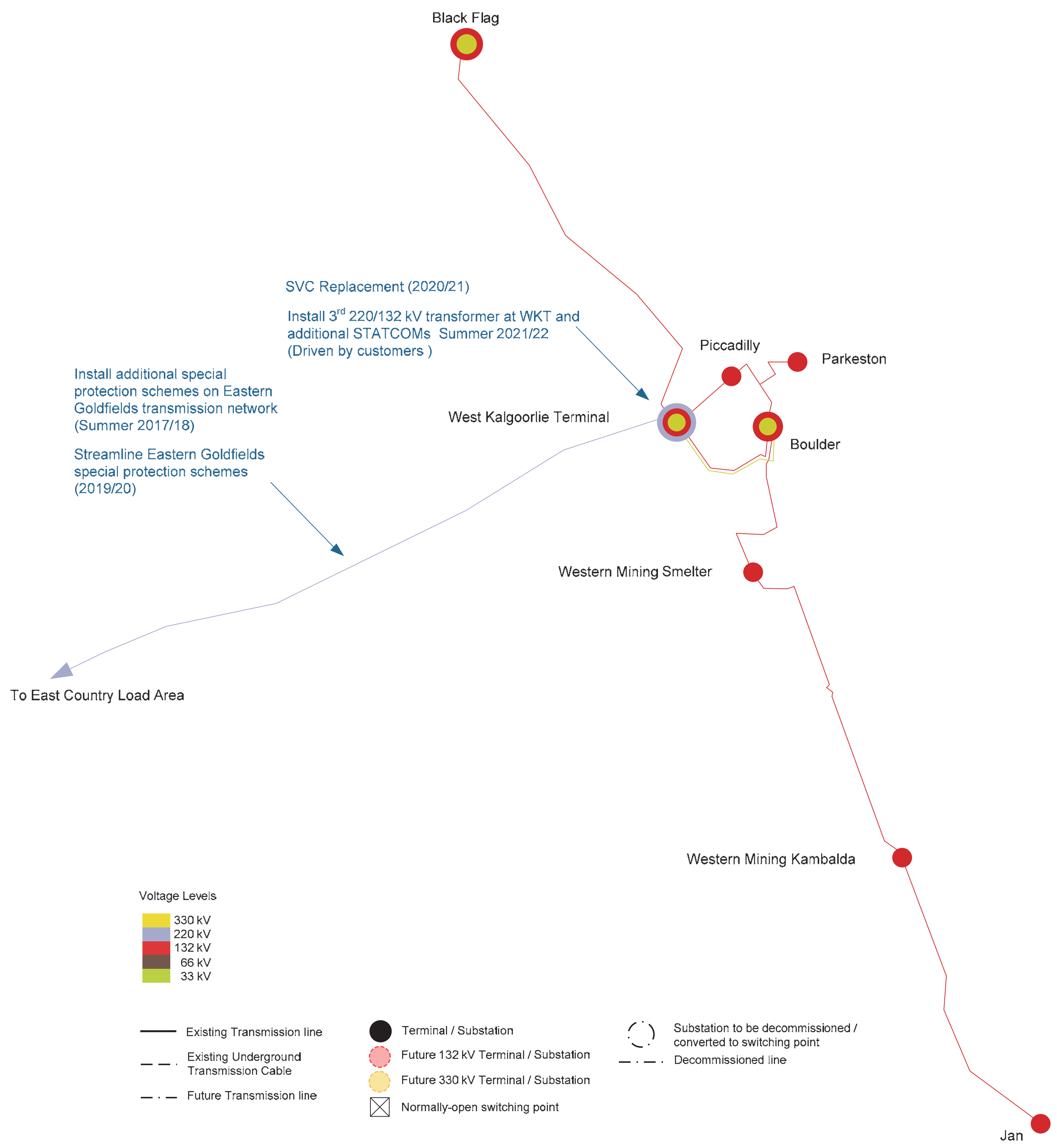
We are currently investigating a number of options to alleviate the voltage and transient stability limitations in the Eastern Goldfields load area. The expected replacement of the ageing saturated reactors at West Kalgoorlie and Merredin terminals with new technology are likely to offer an increase in transfer limits. Table 11 lists the expected benefits of the planned works.

Table 11: Eastern Goldfields load area - planned works and expected benefits

Project	Benefit/s	By when
Install an additional special protection schemes on Eastern Goldfields' transmission network	Relieve rotor angle stability issues in the area.	Summer 2017/18
Streamline Eastern Goldfields special protection schemes	Mitigate operational and maintenance issues associated with the large number of special protection schemes in the area.	Summer 2019/20
Replace SVCs at West Kalgoorlie terminal	Address degraded asset condition	Summer 2020/21
Install a third 220/132 kV transformer at West Kalgoorlie terminal and additional STATCOMs	Accommodate increasing demand in the area.	Summer 2021/22 (Driven by customers)

The preferred transmission network strategy for the Eastern Goldfields load area is shown in Figure 3.

Figure 3: Eastern Goldfields load area - preferred transmission solutions



6.6 East Country load area

The East Country load area covers the Wheatbelt district of the south west and is bound by Sawyers Valley and the outer metropolitan area in the west, Southern Cross in the east, the Muja load area to the south and the North Country load area to the north.

The purpose of the network in the area is to support local load, as well as to provide a link through to the neighbouring Eastern Goldfields load area from the Muja and Guildford load areas. The load area is mostly comprised of rural, water-pumping, mining and residential loads and has historically been characterised by low demand growth rates. The supply to water pumping loads is critical to the water supply to the Eastern Goldfields load area.

The East Country transmission network is connected via 132 kV lines to the Northern terminal and Guildford load areas, as well as 220 kV lines to the Muja and Eastern Goldfields load areas and a 66 kV line to the Cannington load area. The 132 kV networks are normally operated in parallel with the 220 kV interconnection.

Large generation installations, such as Collgar Wind Farm and Merredin Power Station, are connected to the East Country's transmission network. Under some operating conditions, East Country load area can be a net generation exporter.

There is an expectation that with the increased penetration of local generation, particularly from wind farms, the power flow of the local network may become volatile with the fluctuations in their output. This could present some difficulties with operation of the transmission network and system dispatch may become more difficult.

6.6.1 Emerging transmission network limitations within a five year period

Generator connection applications

There are presently a number of connection applications being actively progressed in the East Country load area (see Section 6.20.2 for additional information).

Substation capacity

Load forecasts indicate that the capacity of all substations in the East Country load area is sufficient for the five year outlook.

Asset condition assessments have identified a number of transformers in degraded condition at the following substations:

» Cunderdin substation
» Kellerberrin substation
» Merredin substation
» Mundaring Weir substation
» Northam substation
» Wundowie substation.

Treatment assessments have identified an opportunity to partially refurbish the transformers at Cunderdin, Kellerberrin, Merredin, Northam and Wundowie substations which is expected to defer the replacement plans beyond the five year horizon. However, the Mundaring Weir transformers require mitigation within the five year horizon.

The 66 kV transmission lines supplying Mundaring Weir substation and the 66 kV transmission line connecting Merredin, Carrabin and Yerbillon are ageing and in a degraded condition. Future proposals to address these asset issues will be aligned with the 66 kV long term strategy.

Fault levels

No fault level issues are forecast in the East Country load area over the next five years.

Thermal limits

Under peak demand conditions and following an outage of a 220 kV line between Muja and Merredin terminals, thermal limitations on the 132 kV line between Northam and Merredin may arise due to the loads in Eastern Goldfields. This limitation is currently managed by a protection scheme that will island Eastern Goldfields.

Thermal limitations may also arise as a result of power exports from the East Country load area under lighter load conditions, particularly if these occur in conjunction with high output from generation in the load area. As part of the connection requirements, generation connected in the East Country region operates under a runback scheme to assist with management of this constraint.

Voltage limits

Due to the network security issues in the Muja and Bunbury load areas following the transformer failures at Muja terminal, one of the 220/132 kV transformers at Merredin terminal was relocated to Muja terminal on an interim basis (see Section 6.7.1). This reduces the network security in the

East Country load area. In particular, voltage stability may become problematic in both 66 kV and 132 kV networks west of Merredin under low local generation. In the short term, the use of different network configurations in this area (by moving normally-open points) as a temporary measure is expected to be sufficient to manage these issues. In the medium term, options under investigation include returning the 220/132 kV transformer to Merredin terminal. Voltage issues are also evident around Southern Cross substation.

Merredin substation has two 132/66 kV transformers supplying a local 66 kV sub-transmission network that extends to Northam. This network has the capacity to be operated in parallel with the 132 kV network between Merredin and Northam, however this is rare. Under normal operating conditions, there is an open point between Cunderdin and Kelleberrin to prevent thermal and voltage issues.

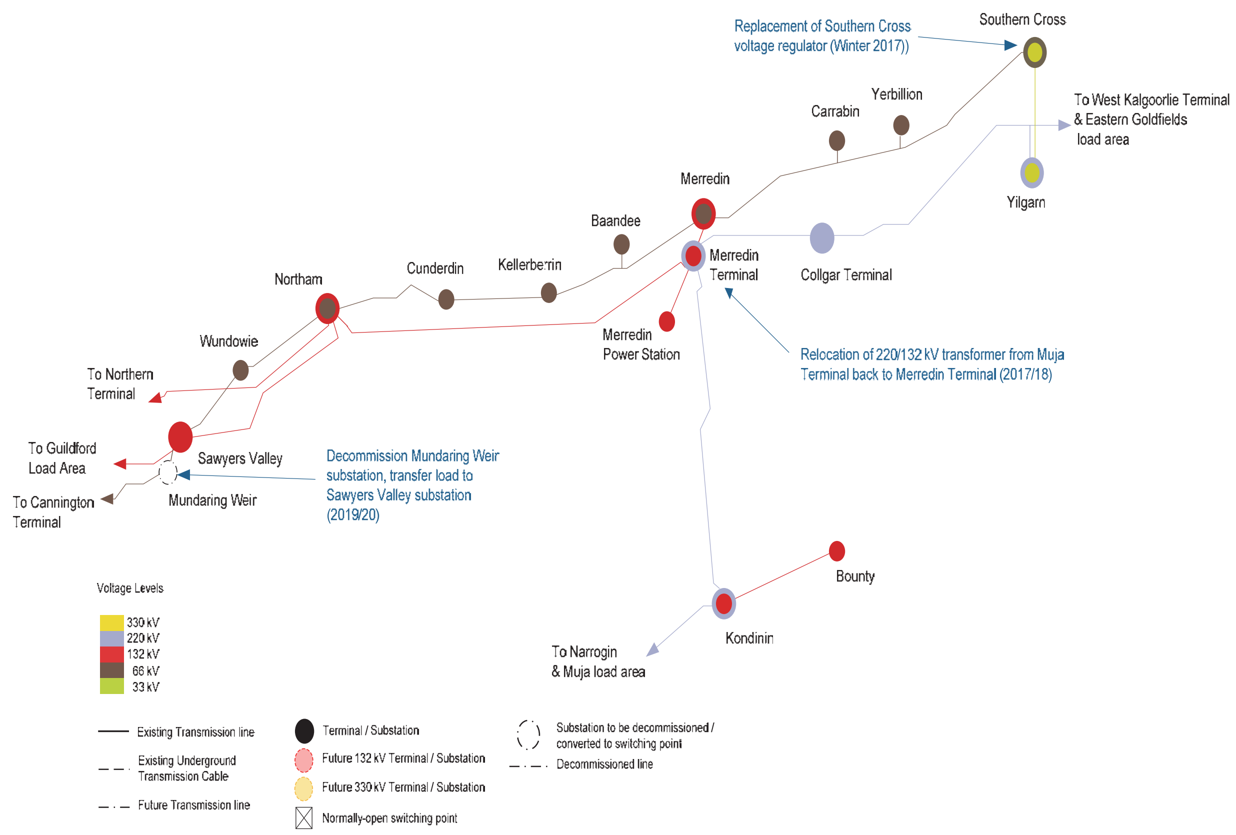
6.6.2 East Country load area transmission system development

The preferred transmission network strategy is shown in Figure 4; Table 12 lists the expected benefits of the planned works.

Table 12: East Country load area - planned works and expected benefits

Project	Benefit/s	By when
Replace Southern Cross substation voltage regulator	Address potential voltage constraints in the area	Winter 2017
Relocate ex-Merredin terminal 220/132 kV transformer from Muja terminal back to Merredin terminal	Address potential voltage constraints in the area.	Summer 2017/18
Decommission Mundaring Weir substation	Address degraded asset condition.	Summer 2019/20

Figure 4: East Country load area - preferred transmission solutions



6.7 Muja load area

The Muja load area extends from Muja Power Station to Manjimup and Beenup in the south west, Albany to the south-east, Boddington to the north and Narrogin in the north-east. The load area includes the agricultural areas of Wagin, Katanning, Kojonup, Mount Barker, Denmark and Albany.

Due to the large geographical extent of the load area, its substations supply peak loads at various points across the period of a year. Substations supplying mostly residential loads have a winter peak pattern with substations supplying predominantly agricultural loads having a summer peak pattern. As a whole, however, the Muja load area is winter-peaking due to heating load.

The Muja load area is connected to the Perth metropolitan area and Bunbury load area via a strong 330 kV transmission network. There is also a single 220 kV transmission line from Muja terminal that supplies Narrogin South terminal and then continues to the Eastern Goldfields, as well as several 132 kV sub-transmission systems connecting to the Bunbury load area.

Given the availability of fuel resources, particularly coal, the area is home to the bulk of base load generating capacity on the network. There is also considerable interest in wind generation projects in the area principally on the coast, but also inland adjacent to transmission infrastructure proposed for mining developments where wind resources are also favourable.

The security and reliability of the network in the Muja load area are paramount because of the reliance of neighbouring load areas on the generation capacity connected to it. In April 2016, the Worsley Alumina 123 MW Worsley co-generation unit was retired, which has reduced security in the area. This is currently managed through operational measures.

The area itself is divided into a number of independent sub-networks supplying load via 132 kV and 66 kV transmission lines. A significant portion of the 66 kV transmission network was built at 132 kV and the long term development strategy for the 66 kV network is to convert it to 132 kV to ensure sufficient network capacity will be available to meet forecast load growth and new customers.

6.7.1 Emerging transmission network limitations within a five year period

Generator connection applications
There are presently a number of connection applications being actively progressed in the Muja load area (see Section 6.20.2 for additional information).

Substation capacity
No substation capacity shortfalls are forecast in the Muja load area over the next five years.

A number of transformers at Wagin and Katanning substations are expected to be replaced between summer 2019/20 and summer 2020/21 respectively due to asset condition. In order to align with the long term development strategy of the area, the replacement transformers are proposed to be 66 kV and 132 kV reconfigurable. Whilst there are no capacity constraints at these sites, the transformer replacement ensures capacity is available for the foreseeable future.

In addition, one of the Beenup transformers is also in degraded condition, however, this transformer can be refurbished which is expected to defer replacement plans beyond the five year horizon.

A number of assets supplying the Collie substation and plant equipment within the substation are degraded. These assets are expected to require replacement beyond the five year horizon. We are currently managing the maintenance of these assets, while investigating network options holistically to optimise plans to address the multiple asset condition issues. Options include a rebuild and resupply of the site from 132 kV, or potential decommissioning and transferring the load to a neighbouring substation.

Fault levels
No fault level issues are forecast in the Muja load area over the next five years.

Thermal limits
Thermal limitations currently exist in the Muja load area under peak demand conditions. These limitations include:

- overloading of Muja BTT2 transformer following outage of Muja BTT3 or Muja BTT1 transformer
- overloading of the Kojonup to Wagin 66 kV circuit following outage of the Kojonup to Katanning 66 kV circuit.

In 2014, Muja terminal was operating in a reduced security state. Two of the three high capacity Bus Tie Transformers (BTT) installed at Muja terminal (Muja BTT1 and BTT2) were out of service following two separate catastrophic failures: one in 2012 and the other in 2014. To mitigate these issues, we completed the following works:

- new 132 kV line from Kemerton terminal to Picton, Pinjarra and Busselton
- relocation of a smaller capacity Merredin terminal 220/132 kV transformer to Muja terminal to replace the failed Muja BTT2 transformer on an interim basis
- replacement of the failed Muja BTT1 transformer with a new similar unit
- Rockingham to Waikiki 132 kV line uprate.

Muja terminal now has all three transformers back in service but Muja BTT2 transformer is of a smaller capacity. As a consequence, the power transfer capacity to Eastern Goldfields is reduced for an N-1 contingency of Muja BTT3 transformer. Overloading of Muja BTT2 transformer may reduce the maximum supportable demand to the Eastern Goldfields and Southwest network. This is currently managed through the out of merit dispatch of generation, special protection schemes and network reconfiguration.

In October 2016, we received the replacement transformer for BTT2 at Muja terminal. This transformer is 250 MVA in capacity and is expected to be in service by the end of 2017.

The Kojonup to Wagin 66 kV circuit is also overloading following the loss of the Kojonup to Katanning 66 kV circuit under peak demand. We are investigating the use of different operational configurations in the 66 kV network by moving or closing normally-open points to manage thermal overloads between Kojonup and Wagin. This has proven effective in managing thermal loading on the Muja to Kojonup 132 kV circuits.

Voltage limits
Under peak demand conditions, voltage instability issues are also experienced in the 66 kV network around Katanning, Wagin and Narrogin for a number of contingencies. To alleviate this issue we are investigating the use of reactive compensation and different configurations in the 66 kV network by moving or closing normally-open points.

Two reactors connected to the tertiary of Muja BTT2 transformer have been assessed to be in degraded condition. We are currently investigating options to address the asset condition issues whilst optimising the reactive power requirements in the area.

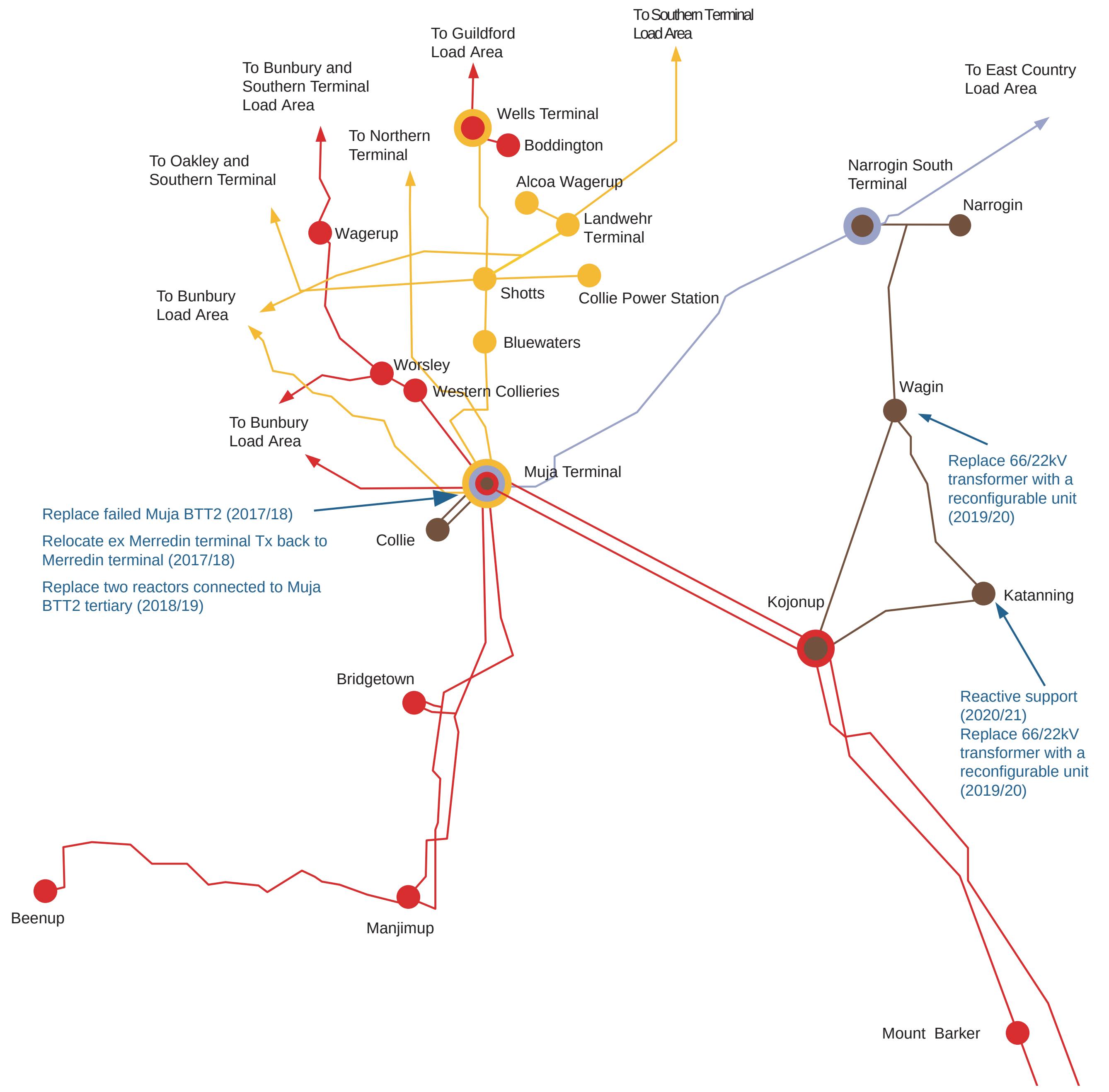
6.7.2 Muja load area transmission system development

The preferred transmission network strategy is shown in Figure 5. Table 13 lists the expected benefits of the planned works.

Table 13: Muja load area - planned works and expected benefits

Project	Benefit/s	By when
Replace failed 220/132 kV bus tie transformer BTT2 at Muja terminal with a new unit	Replace a failed asset.	Summer 2017/18
Resolve Albany Islanding Issues	Address network islanding issues	Summer 2017/18
Replace ex-Merredin terminal 220/132 kV transformer from Muja terminal back to Merredin terminal	Address potential voltage constraints in the area.	Summer 2017/18
Replace two reactors connected to Muja BTT2 transformer's tertiary	Address degraded asset condition; optimise reactive power requirements in the area.	Summer 2018/19
Replace 66/22 kV transformers at Wagin substation with voltage reconfigurable units*	Address degraded asset condition.	Summer 2019/20
Replace 66/22 kV transformers at Katanning substation with voltage reconfigurable units*	Address degraded asset condition.	Summer 2020/21
Install a reactive support at Katanning substation	Address voltage instability issues at Katanning substation	Summer 2020/21
Install a STATCOM at Albany substation	Address voltage step issues in the Albany area	Summer 2019/21

Figure 5: Muja load area - preferred transmission solutions



6.8 Bunbury load area

The Bunbury load area covers the south west corner of the network stretching from Alcoa Pinjarra in the north to Augusta in the south and just west of Wagerup and Worsley.

The network in the Bunbury load area serves, in the main, to supply customer demand south of Kemerton. The bulk of supply to support demand in the area comes from the Muja load area and from Kemerton terminal via a number of 132 kV transmission lines. Power is transferred to Kemerton terminal at 330 kV from Muja terminal, as well as from other 330 kV terminals. Local generation at Kemerton also supports demand.

The 132 kV four ended line connecting Kemerton, Pinjarra, Picton and Busselton is located in high bushfire risk areas and the circuit has been tripped numerous times in the past due to bushfires, leading to supplies relying on lower capacity 66 kV circuits. To reduce the network security risk in the short term, the network is radialised under peak demand conditions. Investigations are underway to reinforce the network over the longer term.

Customer demand south of Picton, including demand at Busselton, Capel and Margaret River represents a considerable portion of the total demand in the load area. This is supplied by a single 132 kV circuit from Picton to Busselton and the ageing 66 kV transmission network that extends from Picton as far south as Margaret River. The transmission network south of Picton is already at its capacity limit and network reconfiguration is required to ensure peak demand can be met. To ensure sufficient long term network capacity, we are investigating options to rebuild the ageing 66 kV transmission network at 132 kV.

6.8.1 Emerging transmission network limitations within a five year period

Substation capacity

Load forecasts indicate the capacity of the following substations in the Bunbury load area will be exceeded within the five year outlook:

» Busselton substation
» Capel substation
» Bunbury Harbour substation.

Asset condition assessments have identified a number of transformers in degraded condition at Busselton, Capel, Coolup, Margaret River and Picton substations.

A number of substation reinforcement plans are in place to address both capacity shortfall and asset condition issues, including new transformer capacity and replacement of ageing transformers with larger capacity units.

The two transformers at Margaret River substation were replaced with a larger and reconfigurable HV (66 kV and 132 kV) transformer in 2016, due to degraded asset condition. While there are no capacity constraints at these sites, the transformer replacement will ensure capacity is available for the foreseeable future.

Capel substation has two 66/22 kV transformers in degraded condition and a capacity shortfall is forecast to occur within the five year outlook. To address these issues and align with the long term development strategy of the area, we propose a staged replacement of the Capel transformers, aligned with the timings of the proposed upgrade works to the Picton to Busselton 66kV circuit. The first stage increases the substation capacity with the installation of an additional transformer of larger capacity by summer 2020/21, while continuing to maintain the two degraded transformers. The second stage falls outside the five year horizon but will involve the replacement of both degraded condition transformers with a similar larger reconfigurable unit.

Busselton substation has two switchyards operating at different voltages. The 66 kV yard has three 66/22 kV transformers in degraded condition and the 132 kV yard has one 132/22 kV transformer in good condition. Capacity shortfall is forecast to occur within the five year outlook.

To address these issues, plans are currently in the execution phase to partially convert the 66kV Busselton substation to 132kV with the installation of an additional 132/22 kV transformer. These plans align with the long term strategy for the area and reduce the reliance on supply from the degraded condition 66/22 kV transformers.

A Picton transformer in a degraded condition is planned to be replaced with a 132/22 kV transformer by summer 2019/20.

In addition to declining substation load at Coolup, the long radial 66kV lines and substation assets are in degraded condition. We have plans to transfer the entire load to the neighbouring Pinjarra substation that will facilitate decommissioning the entire substation and its supplies.

Fault levels
During maximum fault level conditions with all generator units on, the 132 kV fault levels at Bunbury Harbour Substation are approaching switchgear ratings but not exceeding them over the five year period. The issue is being monitored and reassessed annually to determine whether any mitigation is required.

Thermal limits
The load sharing on various 132 kV circuits to the Picton area from Muja and Kemerton terminals is heavily influenced by generation dispatch conditions. Depending on dispatch conditions, a number of other overloads emerge across a five year horizon:

» Southern River to Alcoa Pinjarra/Wagerup 132 kV circuit following the loss of the Alcoa Pinjarra to Pinjarra 132 kV circuit
» Alcoa Pinjarra to Pinjarra 132 kV circuit following a number of contingencies.[30]

A generation runback scheme at Alcoa Pinjarra is currently used to control power flows on the Southern River to Alcoa Pinjarra/Wagerup 132 kV line.

To manage overloads on the Alcoa Pinjarra to Pinjarra 132 kV circuit, we are investigating options such as demand management, generation runback schemes, dynamic line rating and Distributed Flexible AC Transmission technology, including distributed series reactors.

The transmission line between Bunbury Harbour and Muja is approaching the end of its useful life. As part of longer term network development plans, we are considering a number of options, including line rebuild or removal of this line and resupply of the broader Picton area via Kemerton terminal.

Voltage limits
A number of unacceptable low voltage conditions emerge across a five year horizon. These include low voltage conditions at Busselton 132 kV and 66 kV buses and Margaret River 66 kV bus following the loss of the Pinjarra-Kemerton-Picton-Busselton 132 kV circuit.

The recent installation of capacitor banks at Marriott Road and Busselton and the conversion to double circuit of the Kemerton to Marriott Road 132 kV line provide some relief for the voltage limitations, although they are insufficient to ensure adequate supply reliability to the area. We expect the conversion of an existing 66 kV Picton to Busselton line to 132 kV will be completed unless alternative non-network options are more viable, and will offer an increase in maximum supportable demand for the foreseeable future. Timing of this conversion will be outside of the five year horizon.

The section of the 132 kV four ended line connecting Kemerton, Pinjarra, Picton and Busselton traverses through high bushfire risk areas. Recent bushfires in the area have resulted in a high number of line tripping events in the past five years. Considering the regular occurrence of bushfires in the area, a credible network security risk exists for the Picton South area for the next contingency. We are installing a switch on this line to reduce this risk.

6.8.2 Bunbury load area transmission system development

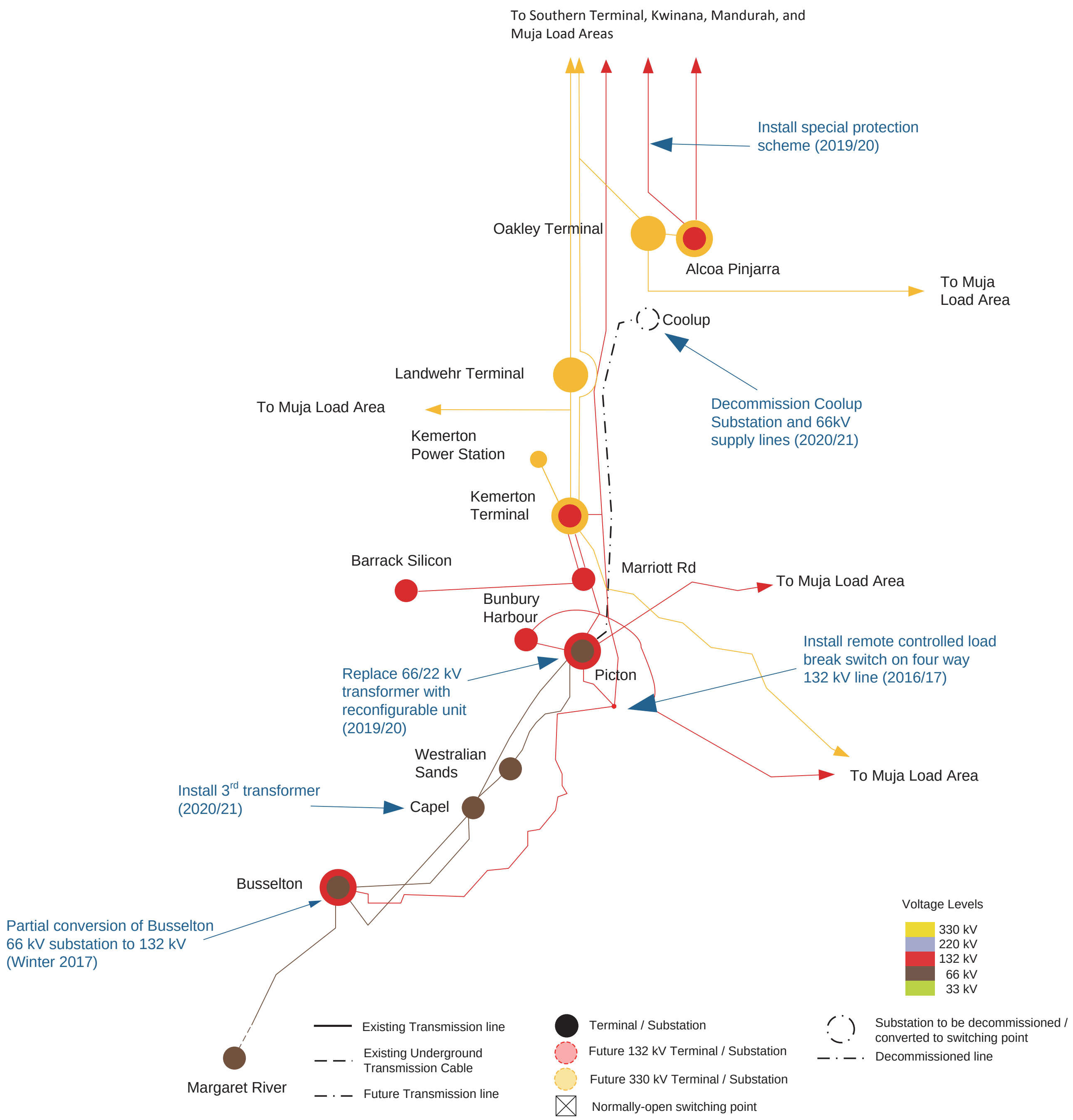
The preferred transmission network strategy is shown in Figure 6. Table 14 lists the expected benefits of the planned works.

[30] Depending on the demand in the area and the generation dispatch at Alcoa Pinjarra and other generation in the Muja load area, the Alcoa Pinjarra to Pinjarra 132 kV circuit is forecast to be overloaded pre-contingent within the five year outlook.

Table 14: Bunbury load area - planned works and expected benefits

Project	Benefit/s	By when
Install switches on Pinjarra-Kemerton-Picton-Busselton 132 kV line	Address the reliability issues during bushfire for the four ended line Pinjarra-Kemerton-Picton-Busselton 132 kV line	Summer 2016/17
Partial conversion of Busselton 66 kV substation to 132 kV*	Address degraded asset condition; accommodate increasing demand in the area.	Winter 2017
Install a special protection scheme on Alcoa Pinjarra to Pinjarra 132 kV line	Mitigate post-contingent thermal constraints on the Alcoa Pinjarra to Pinjarra 132 kV circuit.	Summer 2019/20
Replace a 66/22 kV transformer at Picton substation with a voltage reconfigurable unit*	Address degraded asset condition.	Summer 2019/20
Replace a 66/22 kV transformer at Capel substation with a larger capacity and voltage reconfigurable unit*	Accommodate increasing demand in the area and to address degraded asset condition	Summer 2020/21
Decommission Coolup substation	Address degraded asset condition; consolidation of 66kV network assets.	Summer 2020/21

Figure 6: Bunbury load area - preferred transmission solutions



6.9 Mandurah load area

The Mandurah load area includes the southern metropolitan coastal strip bound by Safety Bay Road in the north (including Waikiki substation), Mandurah and Harvey Estuary in the south and extends east to encompass the Pinjarra substation.

Supply to the Mandurah load area comes from 132 kV transmission lines in the north via Rockingham substation and from the east via Pinjarra substation. The neighbouring Kwinana and Bunbury load areas supply the area with the bulk of its power.

The bulk of load in the area is along the southern metropolitan coastal strip and served by the existing Meadow Springs and Mandurah substations, both of which are experiencing rapid growth. Waikiki substation is further north, at the boundary of the Kwinana load area, and is also experiencing rapid development. The three substations are connected via a single 132 kV tee line along the coast.

6.9.1 Emerging transmission network limitations within a five year period

Substation capacity

Load forecasts indicate the capacity of the following substations in the Mandurah load area will be exceeded within the five year outlook:

» Mandurah substation
» Meadow Springs substation.

A two-staged investment strategy is in place to address these emerging capacity constraints. Partial capacity constraints will be resolved by installing additional transformer capacity at Meadow Springs substation and transferring load from Mandurah to Meadow Springs by summer 2017/18. Full compliance is expected to be restored in 2021/22 by extending Mandurah substation and installing additional transformer capacity.

The proposed project timing for Mandurah substation upgrade works is largely dependent on the realisation of the forecast peak demand. We are now well into the tender process for selecting a preferred supplier/s to deliver an end-to-end non-network option that can defer the need to install additional transformer capacity at Mandurah substation for at least one year. During this period, we will investigate longer term options.

We submitted an application to the ERA for a temporary exemption[31] from compliance with certain requirements of the Technical Rules in relation to the capacity requirements at Meadow Springs substation. In July 2015, the ERA determined that the disadvantages of compliance with the Technical Rules exceeded the advantages, and approved our application.

Fault levels

No fault level issues are forecast for the transmission network in the Mandurah load area over the next five years.

Thermal limits

Several thermal overloads emerge over a five year horizon. These include overloads on the:

» Mandurah to Pinjarra 132 kV circuit following a number of contingencies
» Pinjarra to Meadow Springs/ Cannington terminal 132 kV circuit following the loss of the Mandurah to Pinjarra 132 kV circuit.

Limitations also arise on the 132 kV Alcoa Pinjarra to Pinjarra 132 kV transmission line that connects the Mandurah load area with the Bunbury load area (see Section 6.8.1 for further information).

Demand management, network control service, dynamic line rating and line reactor opportunities are being explored to address these limitations in the short term. Considering the ageing transmission network in the area, we are investigating ways to rebuild of the Mandurah to Pinjarra 132 kV line from single circuit to a double circuit and alleviate both thermal constraints.

[31] Determination on Application for exemption from certain requirements of the Technical Rules submitted by Western Power – Meadow Springs Zone Substation Exemption - https://www.erawa.com.au/cproot/13763/2/determination%20on%20application%20for%20exemption%20from%20certain%20requirements%20of%20the%20technical%20rules%20submitted%20by%20western%20power.pdf

An opportunity to increase the Mandurah to Pinjarra 132 kV circuit line capacity, at minimal additional cost, has recently been identified. Although this may only partially address the thermal issues, it does defer any proposed upgrade works for five years to better align with asset condition drivers as well as providing us a better opportunity to trial and understand dynamic line reactor technology which may address these limitations.

Voltage limits

No voltage instability issues are forecast in the Mandurah load area over the next five years.

6.9.2 Mandurah load area transmission system development

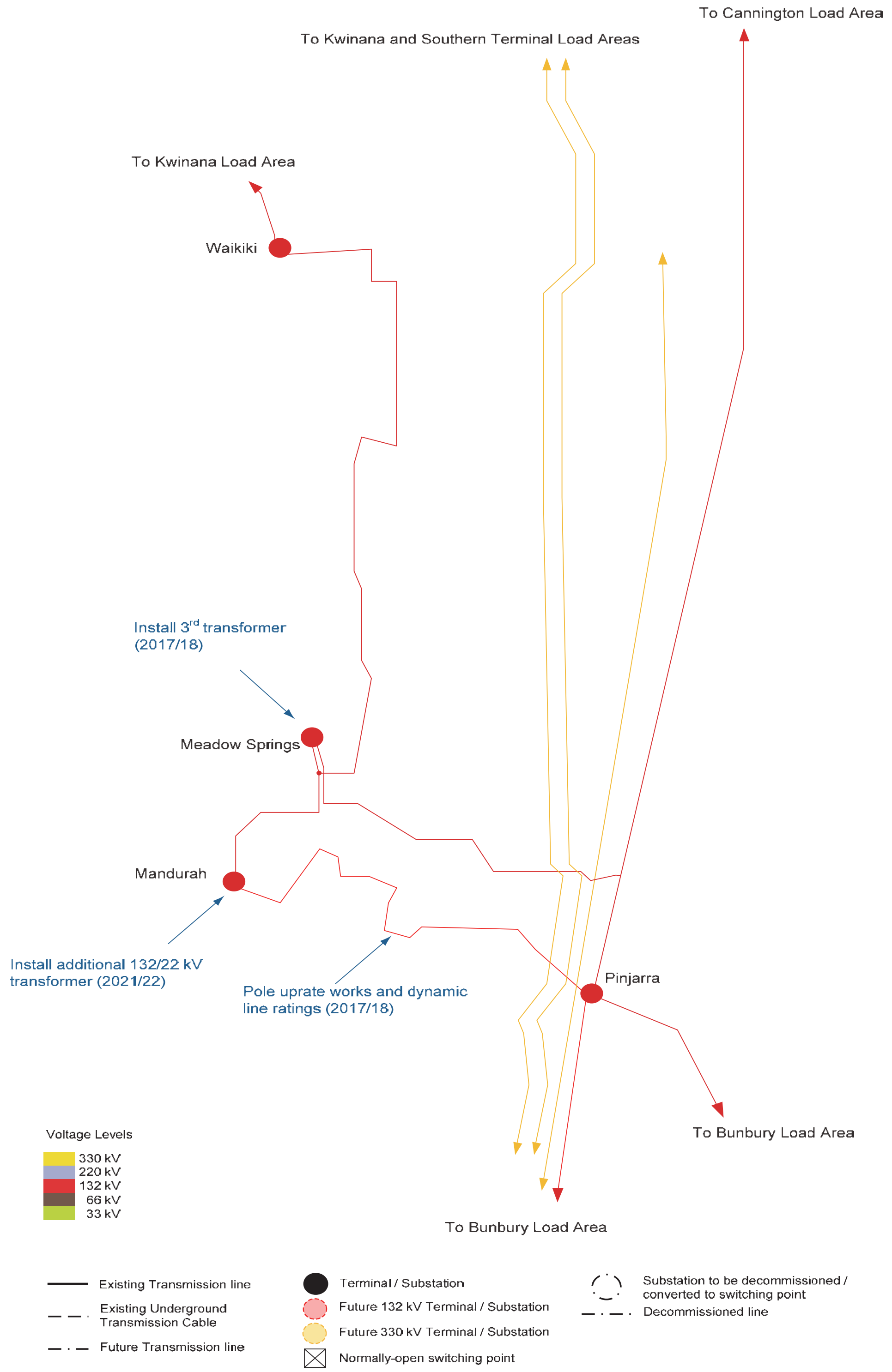
The preferred transmission network strategy is shown in Figure 7. Table 15 lists the expected benefits of the planned works.

Table 15: Mandurah load area - planned works and expected benefits

Project	Benefit/s	By when
Install a third 132/22 kV transformer at Meadow Springs substation*	Accommodate increasing demand in the area.	Summer 2017/18
Mandurah to Pinjarra 132kV line uprate and dynamic line ratings works	Mitigate post-contingent thermal constraints on the Mandurah to Pinjarra 132 kV circuit.	Summer 2017/18[33]
Install a 132/22 kV 66 MVA transformer at Mandurah substation*	Accommodate increasing demand in the area.	Summer 2021/22[34]

[32] This project provides a 5 year deferment of the proposed Mandurah to Pinjarra 132kV double circuit rebuild plans.
[33] Subject to the outcomes of non network investigations

Figure 7: Mandurah load area - preferred transmission solutions



6.10 Kwinana load area

The Kwinana load area lies along the southern metropolitan coastal strip, bound by Beeliar Drive in the north and extending to Safety Bay Road in the south.

The transmission network in this load area is centred on the Kwinana terminal, which is connected to other major terminals (Southern terminal, South Fremantle, Northern terminal, Kemerton and Oakley) via 330 kV and 132 kV transmission circuits. Due to the availability of fuel resources, particularly gas, there has been a strong interest in generation facilities in the area and we continue to receive considerable interest for new entrant generation developments.

Considerable generation retirements have occurred recently at the Kwinana terminal as plants have reached their end of life. The Kwinana 'C' Power Station was fully retired at the end of 2015, reducing generation by approximately 360MW.

Kwinana terminal is a key node of our network's 330 kV backbone system and represents an important site for system reliability and security purposes. A number of load areas rely heavily on supply via Kwinana terminal, both through the 330 kV and 132 kV transmission systems.

A 132 kV sub-transmission system extends south from Kwinana terminal to Rockingham where it connects to the Mandurah load area. A number of 132 kV lines also extend north of Kwinana terminal, connecting to Cockburn Cement substation, Bibra Lake substation, South Fremantle terminal and Southern terminal. The main role of this 132 kV sub-transmission network is to transfer power from the generating plant in the Kwinana load area to nearby industrial loads and to neighbouring load areas.

There are a number of potential large new load developments that may affect the Kwinana area over the medium to long-term, including the Cockburn Coast Development, Latitude 32 and the Australian Marine Complex. There is also considerable residential development east of Thomson Lake.

6.10.1 Emerging transmission network limitations within a five year period

Substation capacity

No substation capacity shortfalls are forecast in the Kwinana load area over the next five years.

In 2015, a third transformer was installed at Mason Road substation to accommodate new customer connections and transfer of the entire British Petroleum substation load to facilitate retiring the degraded substation assets at British Petroleum substation.

With the completion of the above project, the Broken Hill Kwinana substation is the remaining load supplied by the 66 kV network. An alternative supply for Broken Hill Kwinana substation is being investigated. Although currently beyond the five year horizon, this would facilitate the retirement of the degraded 132/66 kV Kwinana step down transformer and 66 kV transmission network as well as reducing the network losses in the area.

Fault levels

Due to the meshed nature of the network at Kwinana and Southern terminals, coupled with high levels of generation, fault level issues can be problematic. The recent retirement of Kwinana 'C' has slightly reduced the fault levels, however, this issue still requires reinforcement. During typical peak demand conditions, most generation in the area is operational and the single 330/132 kV transformer at Kwinana terminal must be out of service to manage this issue. This practice has been adequate for a number of years although fault levels in the area are now approaching limits again, despite having the transformer out of service.

In order to relieve fault levels in the area, particularly around Kwinana and Southern terminals, we are proposing a minor network reconfiguration with partial de-meshing of the Kwinana and Southern terminal 132 kV networks. This project converts the Kwinana terminal to Southern terminal 132 kV circuit into a Kwinana terminal to South Fremantle terminal 132 kV circuit, bypassing Southern terminal, as well as reinforcing the 132 kV Kwinana to Medina and Cockburn Cement tee line. This project is anticipated to be in service by summer 2017/18. The project is part of a staged series of work planned for the Kwinana area in response to new entrant load and generator connections.

Thermal limits

A thermal overload on the 132 kV network from Kwinana terminal to Cockburn Cement and Medina may occur following a number of contingencies. This thermal overload will be addressed by the planned works to partially de-mesh the Kwinana and Southern terminals by summer 2017/18.

Voltage limits

No voltage instability issues are forecast in the Kwinana load area over the next five years.

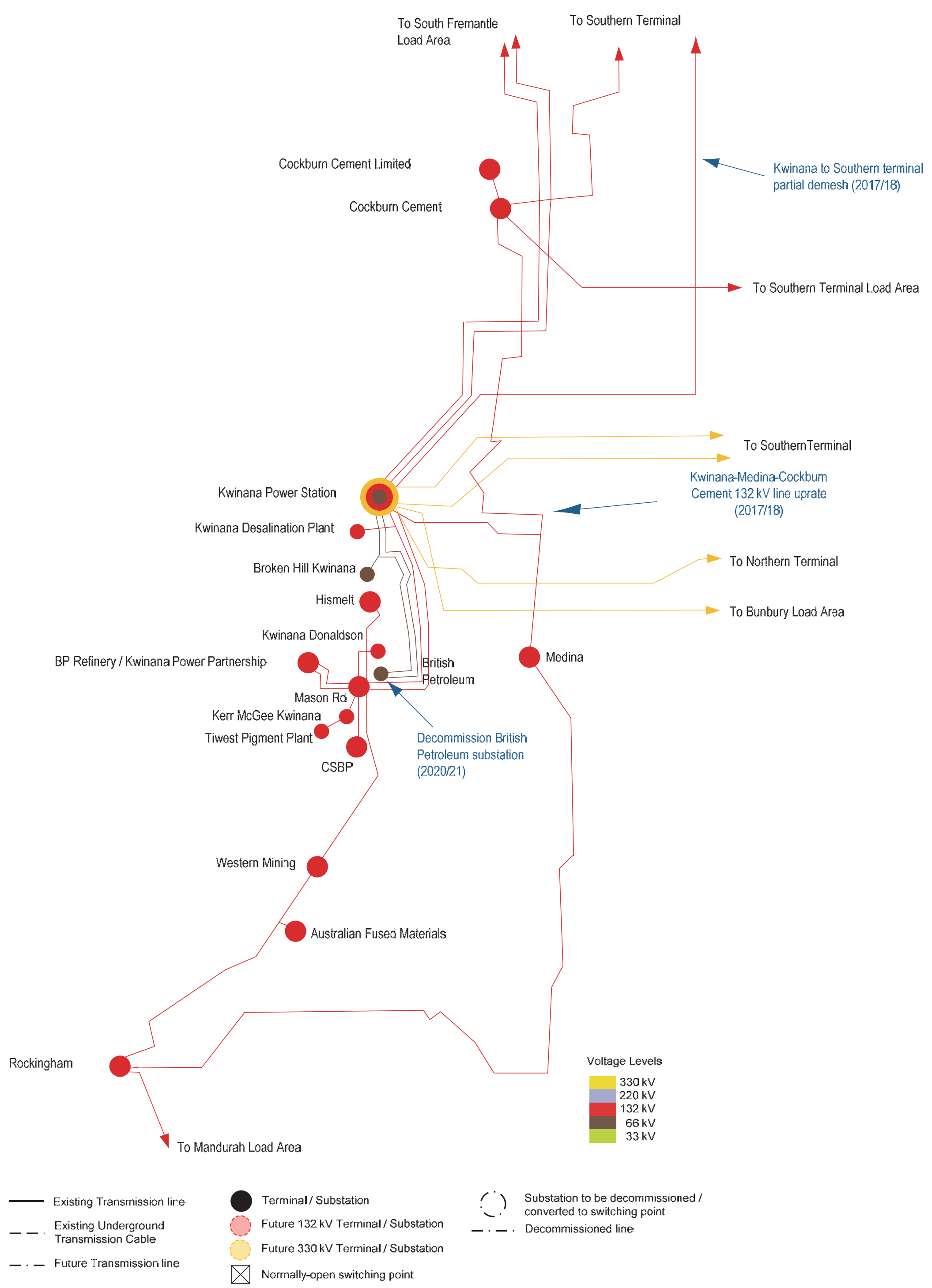
6.10.2 Kwinana load area transmission system development

The preferred transmission network strategy is shown in Figure 8. Table 16 lists the expected benefits of the planned works.

Table 16: Kwinana load area - planned works and expected benefits

Project	Benefit/s	By when
Kwinana to Southern terminal partial de-mesh and Kwinana-Medina-Cockburn Cement line uprate	Reduce fault levels; relieve thermal limitations.	Summer 2017/18
Decommission British Petroleum substation	Address degraded asset condition.	Summer 2020/21

Figure 8: Kwinana load area - preferred transmission solutions



6.11 Southern terminal load area

Southern terminal load area covers the region bound by Riverton and Canning Vale in the north, Cockburn in the west and Byford in the south-east.

The network in the area has strong 330 kV ties with generation centres in the south of the SWIS (Muja and Bunbury areas), as well as 330 kV connections with Kwinana, Cannington (via Kenwick Link) and Guildford terminal. A number of load areas rely heavily on Southern terminal through the 330 kV and 132 kV transmission systems, including South Fremantle (and further north to Western terminal) and East Perth.

Multiple 132 kV sub-transmission circuits extend from Southern terminal, where they form a meshed arrangement supplying substations as far south as Byford and north towards Cannington terminal. Both Southern terminal and Cannington terminal support these substations within the mesh, depending on operating conditions. From Southern River a 132 kV circuit extends south to Alcoa Pinjarra in the Bunbury load area.

There is no notable generation in the Southern terminal load area and most supply comes from the 330 kV transmission system via three 490 MVA 330/132 kV transformers connected to Southern terminal. A number of other 132 kV circuits connected to neighbouring load areas also support the demand.

Southern terminal is an important site for the interconnection of circuits on the bulk transmission network. It is a focal point for supply from the 330 kV system and subsequent supply to numerous 132 kV sub-transmission systems supporting the broader south metropolitan load. The 132 kV transmission lines directly connect Southern terminal to South Fremantle, East Perth terminal and Kwinana terminal. These connections provide a significant power supply to the South Fremantle, East Perth and CBD demand.

The meshed nature of the 132 kV circuits between Cannington and Southern terminal presents challenges for its longer term development. Existing infrastructure has been established over time, largely as multiple single circuit connections between various substations in the Southern and Cannington terminals, rather than as double circuit transmission networks from each of the terminals connected to more radialised substation loads. While the existing practice attempts to optimise use of existing 132 kV assets, it presents issues with operational control over power transfers and challenges for longer term network development. This configuration also has a tendency to increase fault levels and reduce use of the 330 kV network. This is because the multiple meshed 132 kV circuits provide a lower impedance path than the 330 kV routes, particularly between Southern terminal and Cannington load area.

6.11.1 Emerging transmission network limitations within a five year period

Generator connection applications

There are presently a number of connection applications being actively progressed in the Southern terminal load area (see Section 6.20.2 for additional information).

Substation capacity

No substation capacity shortfall is forecast in the Southern terminal load area over the next five years.

Asset condition assessments have identified a number of transformers in degraded condition at Canning Vale and Gosnells substations. Treatment assessments have identified an opportunity to partially refurbish the transformers which is expected to defer the replacement plans beyond the five year horizon.

Fault levels

Due to the heavily meshed 330 kV and 132 kV network at Southern terminal, the fault levels are high. A significant contribution to the fault level comes from the 132 kV direct connection between Kwinana terminal and Southern terminal, which raises fault levels considerably at both sites. Current operational practice is to remove the Kwinana 330/132 kV bulk transformer from service under periods of high local generation. Even with this transformer out of service, fault levels are again now at equipment limits. Current plans involve a partial de-mesh of the Kwinana and Southern terminal load areas to address these limitations (see Section 6.10.1 for further information).

Thermal limits

Flat load growth is forecast in the load area. As a result, power system studies have identified very few thermal limitations in the Southern terminal load area over the next five years. Under conditions with very high south generation, overloads on the 132 kV network from Southern terminal to East Perth terminal are evident following the loss of a parallel circuit.

A special protection scheme was initially planned to provide an automated response to address this limitation although following negotiations with Network Operations, manual intervention was deemed sufficient at this stage. Current operational practice is to close the normally-open circuit breaker at Belmont substation in response to the critical contingency. This connects Belmont substation with Northern terminal and East Perth, providing another path for supply to the CBD, therefore lowering flows on the remaining Southern terminal to East Perth circuit.

Voltage limits

No voltage instability issues are forecast in the Southern Terminal load area over the next five years.

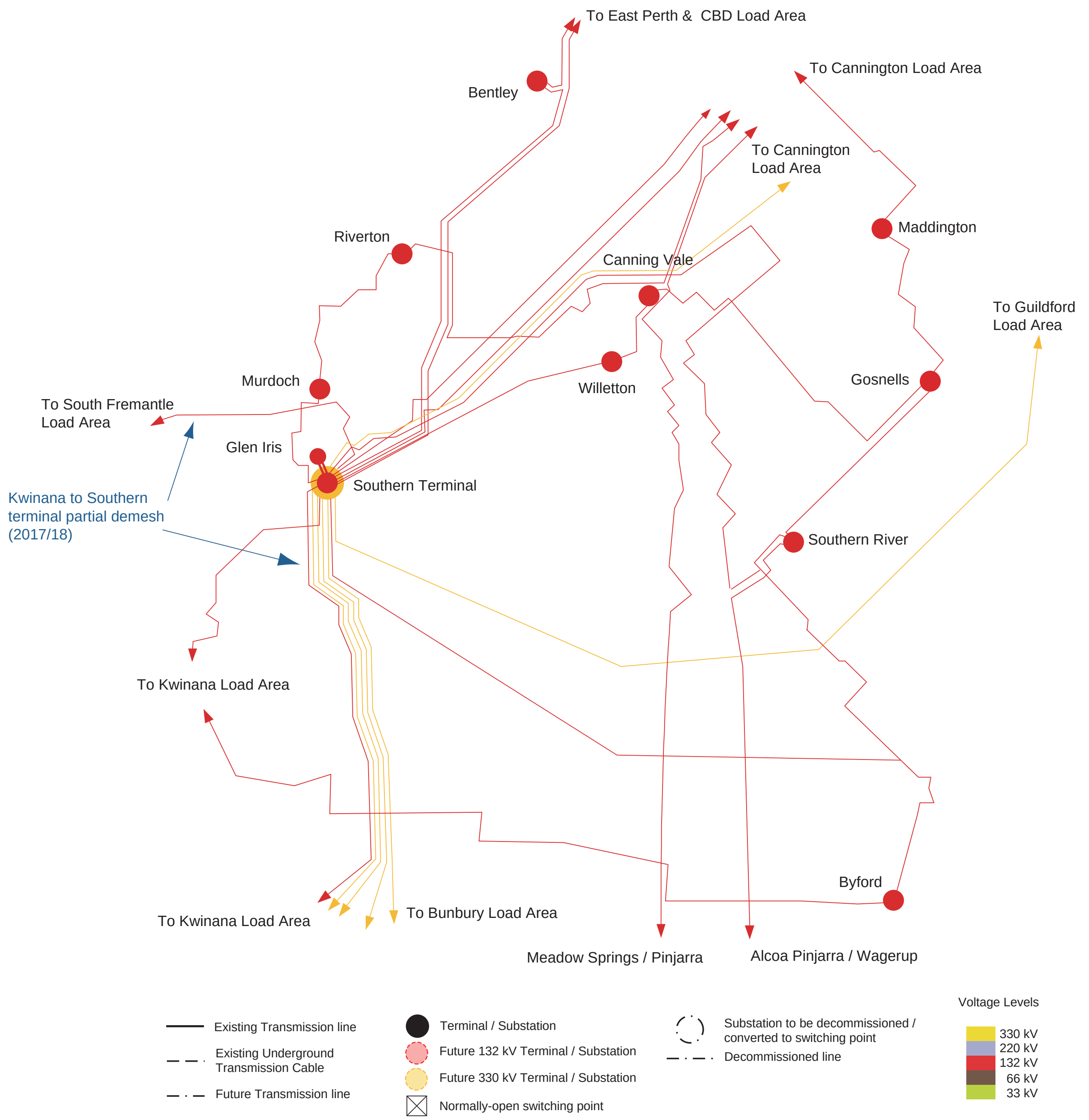
6.11.2 Southern terminal load area transmission system development

The preferred transmission network strategy is shown in Figure 9. Table 17 lists the expected benefits of the planned works.

Table 17: Southern terminal load area - planned works and expected benefits

Project	Benefit/s	By when
Kwinana to Southern terminal partial de-mesh	Reduce fault levels; relieve thermal limitations.	Summer 2017/18

Figure 9: Southern terminal load area - preferred transmission solutions



6.12 South Fremantle load area

The South Fremantle load area extends from Beeliar Drive in the south, to the Swan River at its northern boundary and from the coast to the Myaree area in the east.

The network in the area serves primarily to supply local substation loads, the bulk of which are connected to South Fremantle terminal via a 66 kV sub-transmission network. Supply to South Fremantle terminal comes from Southern terminal via a 132 kV circuit, as well as from Kwinana terminal via two 132 kV circuits, one of which supplies Bibra Lake substation en-route. The South Fremantle load area is also connected to the Western terminal load area via a 132 kV circuit between Amherst and Cottesloe substations, as well as a 66 kV circuit connecting North Fremantle substation with the Western terminal 66 kV network. This 66 kV circuit is normally open at North Fremantle substation end and is typically used only to increase reliability of supply to substations under outage conditions.

An ageing 66 kV network supports the bulk of the existing substations in the area. Due to its capacity and age, the 66 kV network is expected to require substantial reinforcement over the next 20 years. We are currently investigating a long term strategy to upgrade the South Fremantle 66 kV network to 132 kV. This may involve converting Myaree and O'Connor substations into new 132 kV ready substations, decommission Australian Paper Mills substation and resupply from Bibra Lake substation via distribution supplies and an additional transformer at Bibra Lake Substation.

6.12.1 Emerging transmission network limitations within a five year period

Substation capacity

No substation capacity shortfall is forecast in the South Fremantle load area over the next five years.

Transformers at the Australian Paper Mills, Myaree, and South Fremantle substations are degraded. One transformer at Myaree requires replacement, however, treatment assessments have identified refurbishment opportunities for the remaining transformers which will defer their replacement plans beyond the five year horizon. To align with the long term development strategy of the area, the replacement transformers are proposed to be reconfigurable HV, 66 kV and 132 kV, transformers. We are also investigating longer term options that may include decommissioning substations within the 66 kV South Fremantle network or consolidating substations by using larger substation transformers.

One of the oil filled cables between Edmund Street and North Fremantle substation was decommissioned to mitigate the environmental risk. North Fremantle substation decommission plans were also brought forward, which includes decommissioning the remaining cable by winter 2017 and resupplying the North Fremantle load from Cottesloe and Edmund Street substations.

Fault levels

The fault level at North Fremantle 66 kV substation is projected to exceed equipment ratings within a five year outlook. The planned partial de-mesh of Kwinana and Southern terminals at 132 kV by summer 2017/18 is expected to offer some benefits (see Section 6.10.1 for further information). From winter 2017, the North Fremantle substation will become de-energised, avoiding the need to upgrade the under fault rated equipment.

Thermal limits

There are no thermal issues forecast in the South Fremantle load area over the next five years.

Voltage limits

There are no voltage stability issues forecast in the South Fremantle load area over the next five years.

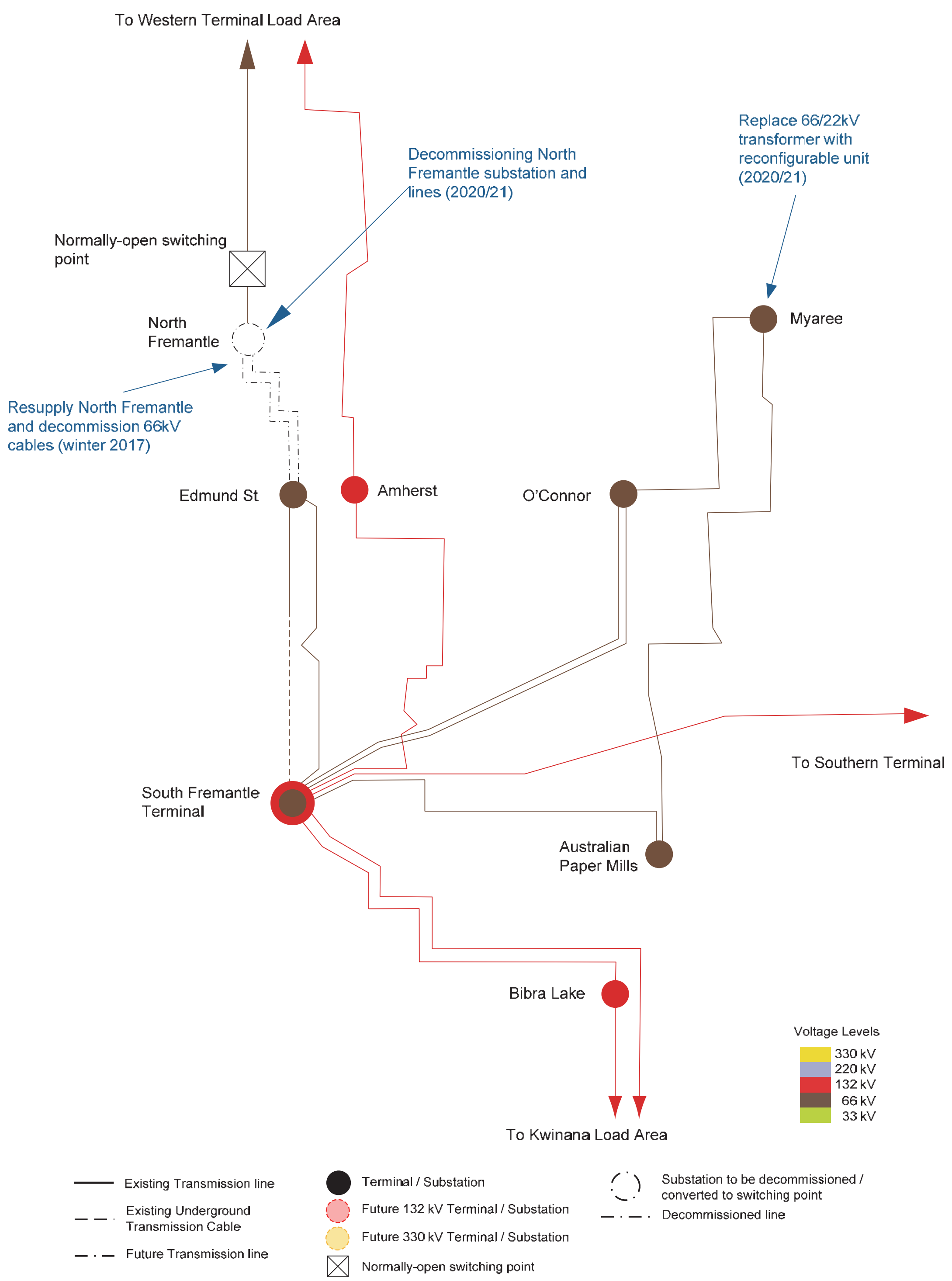
6.12.2 South Fremantle load area transmission system development

The preferred transmission network strategy is shown in Figure 10. Table 18 lists the expected benefits of the planned works.

Table 18: South Fremantle load area - planned works and expected benefits

Project	Benefit/s	By when
Resupply North Fremantle substation from adjacent substations and decommissioning of the remaining fluid-filled cable section between North Fremantle and Edmund Street	Address degraded asset condition.	Winter 2017
Replace 66/22 kV transformer at Myaree substation with voltage reconfigurable unit*	Address degraded asset condition; accommodate increasing demand in the area.	Summer 2020/21
Decommission North Fremantle substation	Address degraded asset condition.	Summer 2020/21

Figure 10: South Fremantle load area - preferred transmission solutions



6.13 Cannington load area

The Cannington load area is situated in the south eastern corridor of the metropolitan area and is bordered by the Swan and Canning Rivers and extends east from the CBD to Mundaring.

The network within the Cannington load area serves the primary purpose of supplying substations connected in the 132 kV and 66 kV sub-transmission networks extending from Cannington terminal.

Cannington terminal is the focal point of the load area, with transmission connections to Southern terminal, including 132 kV circuits and a 330 kV circuit via Kenwick Link, providing the majority of the area's power requirements. A 132 kV sub-transmission system extends north from Cannington terminal to connect Welshpool, Rivervale, Belmont and Kewdale substations.

Cannington terminal also supports a 66 kV network to the west that connects Clarence Street, Collier Street, Tate Street, Victoria Park and one customer-owned substation. Another 66 kV transmission line extends east to connect Mundaring Weir, which is in the East Country load area.

The meshed nature of the 132 kV and 330 kV circuits between Cannington and Southern terminal provides challenges for its longer term development. Existing infrastructure has largely been established over time as multiple single circuit connections between various substations in Southern and Cannington terminals, rather than a double circuit transmission network from each of the terminals connected to more radialised substation loads. While this optimises the use of existing 132 kV assets, it presents challenges with operational control over power transfers and longer term network development in the area. This configuration also has a tendency to increase fault levels and reduce use of the 330 kV network. This is because the multiple meshed 132 kV circuits provide a lower impedance path over 330 kV routes, particularly between Southern and Cannington terminals.

6.13.1 Emerging transmission network limitations within a five year period

Substation capacity

No substation capacity shortfall is forecast in the Cannington load area over the next five years.

A number of assets within the 66 kV Cannington network, in particular the supply lines and substation transformers at Tate Street and Collier Street are starting to show signs of asset deterioration and options for decommissioning these sites in the long term are under investigation. Treatment assessments have identified an opportunity to partially refurbish both transformers, which is expected to defer the replacement plans beyond the five year horizon.

Over the past decade, the condition of the transformers, switchboards and 6.6 kV distribution network at Victoria Park substation had severely degraded. This network has been progressively converted and upgraded to 22 kV. The substation's load was resupplied from the Rivervale substation and the substation was de-energised, other than the 66 kV switchgear. We are now investigating the complete retirement of the substation.

Fault levels

The fault level at Collier Street 66 kV substation is projected to exceed equipment specifications on some plant within the next five years. We plan to address these limitations through replacement of under fault rated equipment.

Thermal limits

There are no thermal issues forecast in the Cannington load area over the next five years.

Voltage limits

There are no voltage stability issues forecast in the Cannington load area over the next five years.

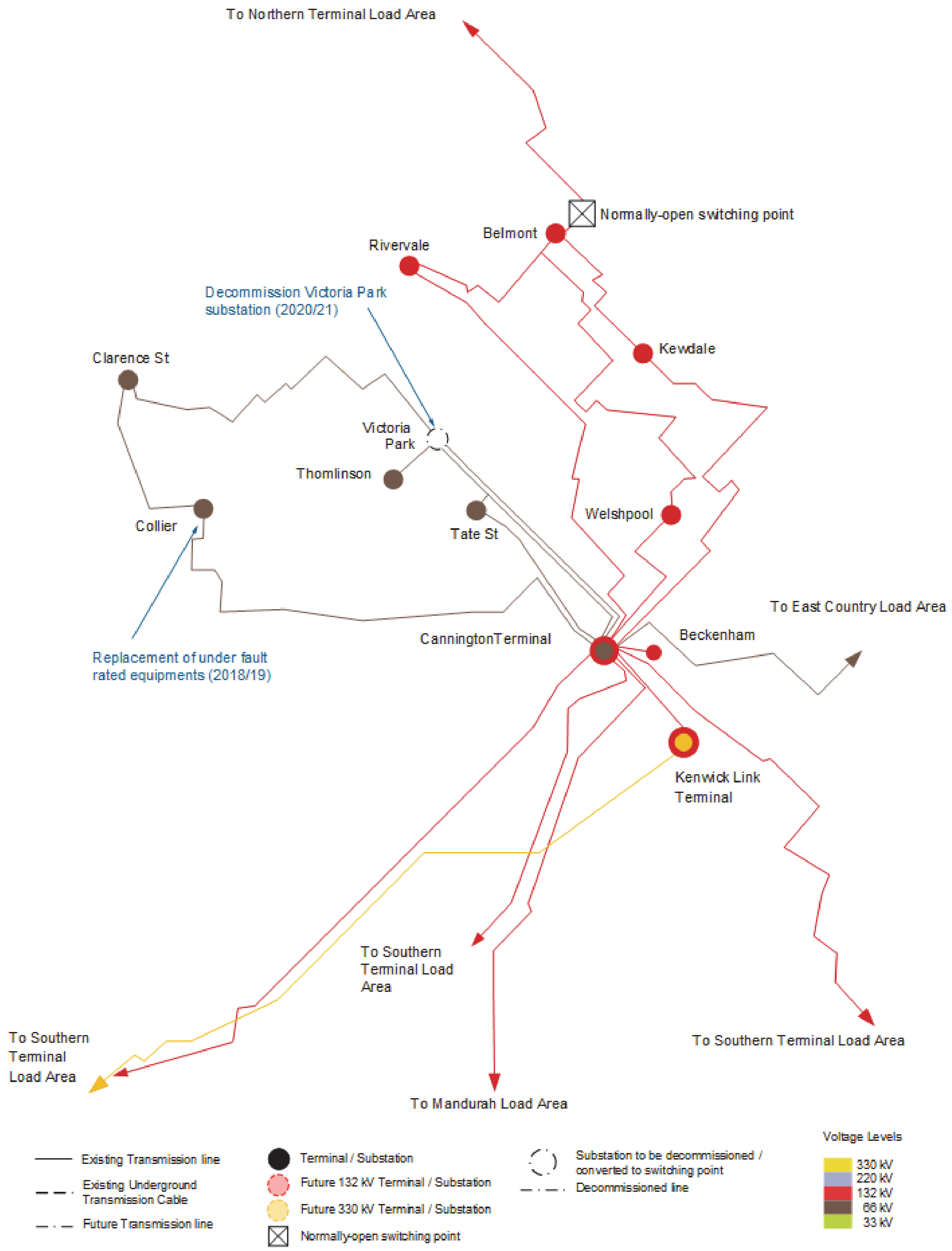
6.13.2 Cannington load area transmission system development

The preferred transmission network strategy is shown in Figure 11. Table 19 lists the expected benefits of the planned works.

Table 19: Cannington load area - planned works and expected benefits

Project	Benefit/s	By when
Replace under fault rated equipment at Collier 66 kV substation	Mitigate fault level constraints	Summer 2018/19
Decommission Victoria Park substation	Address degraded asset condition	Summer 2020/21

Figure 11: Cannington load area - preferred transmission solutions



6.14 East Perth and CBD load area

The East Perth and CBD area includes the Perth CBD, the City of Subiaco and the City of Vincent.

The network in this area supports the densely populated regions of West Perth, East Perth and the CBD. Given the centralised high density nature of load, the area has a heavy reliance on supply from neighbouring load areas including Southern terminal, Northern terminal, Cannington and Western terminal.

The East Perth and CBD load area is centred on the East Perth terminal, which delivers power to substations within the Perth inner metropolitan region, including the CBD. It acts almost entirely as a load terminal and supplies seven zone substations via 132 kV and 66 kV sub-transmission networks. Given the load density, in most operating conditions there are no through-flows from the south of the load area to the north. Power transfer can, however, go from East Perth terminal to Northern terminal under lightly loaded conditions, particularly with minimal generation operating in the north of the network.

Supply into the load area comes from two 132 kV cables that cross the Swan River via the Graham Farmer Freeway, which connects Southern terminal and East Perth load areas. There is also one 132 kV transmission line/cable between Western terminal and Cook Street substation.

A transmission line from Belmont substation in the Cannington load area forms a tee line with a 132 kV circuit connecting East Perth to Northern terminal. Western Power has identified advantages having the Belmont end of this tee line normally open and now operates the network in this manner. Two 132 kV circuits from Northern terminal also support a significant portion of CBD substation load at Milligan Street substation via Mount Lawley.

Construction of new transmission lines in the load area is likely to be difficult due to limited access points across the Swan River, service congestion and scarcity of available land. This translates to significant challenges in planning new injection points and new substation connections.

The construction of new transmission lines and zone substations in the area will face challenges in gaining environmental and community approvals, incurring significant cost associated with construction and planning. Reinforcements in the load area are also likely to incur higher project costs.

The transmission lines in this load area are generally designed to meet the N-1 capacity criterion with the exception of supply capacity into the Perth CBD, which is designed to the N-2 criterion to cater for the increased security of supply requirements[34].

6.14.1 Emerging transmission network limitations within a five year period

Substation capacity

An N-2 capacity shortfall between Hay Street and Milligan Street substations currently exists during periods of peak demand. A committed project is now in the planning phase, it involves installing a new 132 kV cable between Hay Street and Milligan Street substations to address the N-2 shortfall and is proposed for completion by summer 2019/20.

Asset condition assessments have identified a number of transformers in degraded condition at the following substations:

» Forrest Avenue substation
» Hay Street substation
» Milligan Street substation
» Wellington Street substation.

Treatment assessments have identified an opportunity to partially refurbish the transformers at Hay Street, Milligan Street and Wellington Street substations which is expected to defer the replacement plans beyond the five year horizon. However, the Forrest Avenue transformers require replacement.

[34] https://www.erawa.com.au/cproot/14411/2/edm%2040518689%20-%20technical%20rules%201st%20august%202016%20publish%20version%20-%20fri.pdf

In addition, the 11 kV switchboards at Forrest Avenue, Milligan Street and Hay Street substations are degraded. The Hay Street switchboards are planned to be replaced by summer 2020/21, with the

Milligan Street switchboard replacements occurring just beyond the five year horizon.

With multiple asset condition issues at Forrest Avenue substation and surrounding substations, planning is underway for the construction of a new 132 kV CBD substation just beyond the five year horizon to facilitate the decommissioning of older 66 kV substations, such as Forrest Avenue substation. This plan better aligns with the broader long term plans for the load area and represents a more efficient solution than 'like for like' replacements.

Fault levels

The fault level at the following sites is projected to exceed equipment specifications on some plant within a five year outlook:

» Hay Street substation
» Milligan Street substation
» Summer Street substation.

We are currently planning to replace the under fault rated equipment by summer 2018/19.

Thermal limits

Under conditions with very high southerly generation, overloads on the 132 kV network from Southern terminal to East Perth terminal are evident following the loss of a parallel circuit. This limitation is managed through manual network reconfiguration by Network Operations (see Section 6.11.1 for further information).

Voltage limits

There are no voltage stability limitations identified in the CBD and East Perth load area across a five year outlook.

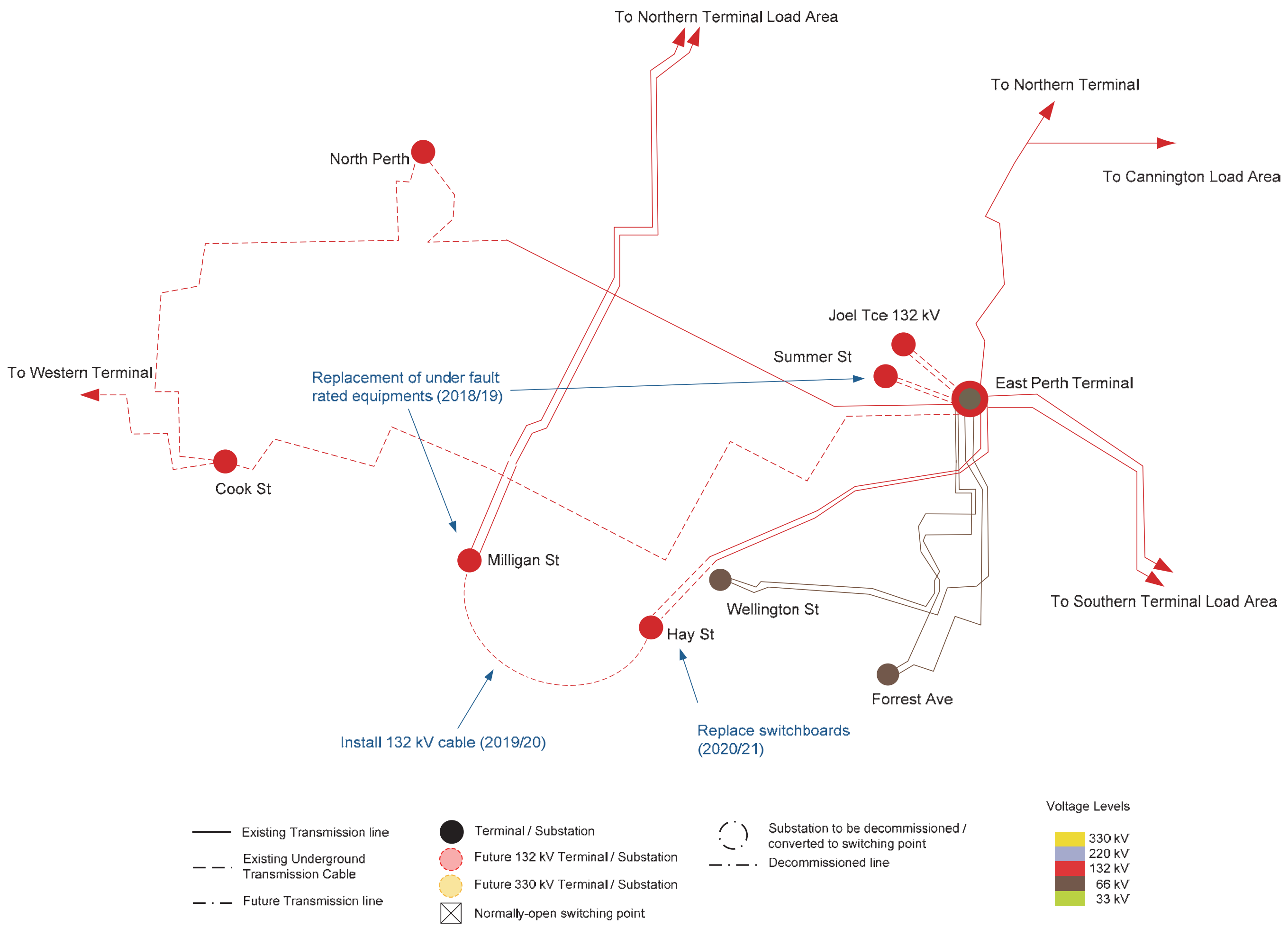
6.14.2 East Perth and CBD load area transmission system development

The preferred transmission network strategy is shown in Figure 12. Table 20 lists the expected benefits of the planned works.

Table 20: East Perth and CBD load area - planned works and expected benefits

Project	Benefit/s	By when
Replace under fault rated equipment at Milligan Street and Summer Street substations	Mitigate fault level constraints.	Summer 2018/19
Install a 132 kV cable between Hay Street substation and Milligan Street substation	Increase maximum supportable demand in the CBD under N-2 conditions.	Summer 2019/20
Replace 11 kV switchboards at Hay Street substation	Address degraded asset condition.	Summer 2020/21

Figure 12: East Perth and CBD load area - preferred transmission solutions



6.15 Western terminal load area

The Western terminal load area supplies the area bordered by the Perth CBD to the east, the Swan River to the south, the west coast and Wembley Downs to the north.

The network in this area supports load in the western metropolitan suburbs. There are three 132 kV transmission circuits connected to Western terminal that provide its supply. The majority of power is delivered into the load area from overhead lines originating from Northern terminal and South Fremantle terminal. The transmission line from South Fremantle terminal crosses the Swan River and travels north through the suburbs of Cottesloe and Nedlands, supplying Cottesloe and Amherst substations in the South Fremantle load area. The other 132 kV circuit connects Western terminal with Cook Street substation.

Supply to substations is currently achieved through a 66 kV sub-transmission network, which forms two distinct rings. A northerly 66 kV ring supplies the Wembley Downs, Herdsman Parade and Shenton Park substations and the southerly ring supplies the Medical Centre, University and Nedlands substations. The 66 kV network is nearing the end of its useful life. This, coupled with the need to support future load growth in the area, is driving a conversion from 66 kV to 132 kV assets over time.

Many of the substations and transmission lines in this area are now exceeding their expected service lives and are requiring significant replacement works.

Our staged transition to 132 kV is underway with projects in both the northern and southern 66 kV networks upgrading to 132kV voltage and consolidating the assets in the area.

6.15.1 Emerging transmission network limitations within a five year period

Substation capacity

We recently completed the new Medical Centre substation addressing the capacity shortfall and degraded asset condition issues at Medical Centre substation. The new substation will also permit the decommissioning of University substation, which has capacity shortfall and multiple assets in degraded conditions, by 2017/18.

Similarly, we commissioned a new 132 kV substation at Shenton Park in 2016. This facilitates the decommissioning of the old Shenton Park and Herdsman Parade 66 kV substations due to degraded asset condition by 2018/19.

Nedlands substation assets are also degraded. A committed project is currently transferring the entire Nedlands substation load to adjacent substations and will partially decommission the substation by summer 2018/19. The 66 kV assets at Nedlands will remain in service until further asset condition issues trigger the replacement of the connecting 66 kV transmission lines.

The 66 kV Wembley Downs and 132 kV Western terminal transformers are degraded. Treatment assessments have identified an opportunity to partially refurbish the transformers which is expected to defer the replacement plans beyond the five year horizon.

Fault levels

The fault level at the following sites is projected to exceed equipment specifications on some plant within a five year outlook:

» Western terminal 132 kV
» Wembley Downs substation 66 kV.

Thermal limits

No thermal issues are forecast in the Western terminal load area over the next five years.

Voltage limits

No voltage instability issues are forecast in the Western terminal load area over the next five years.

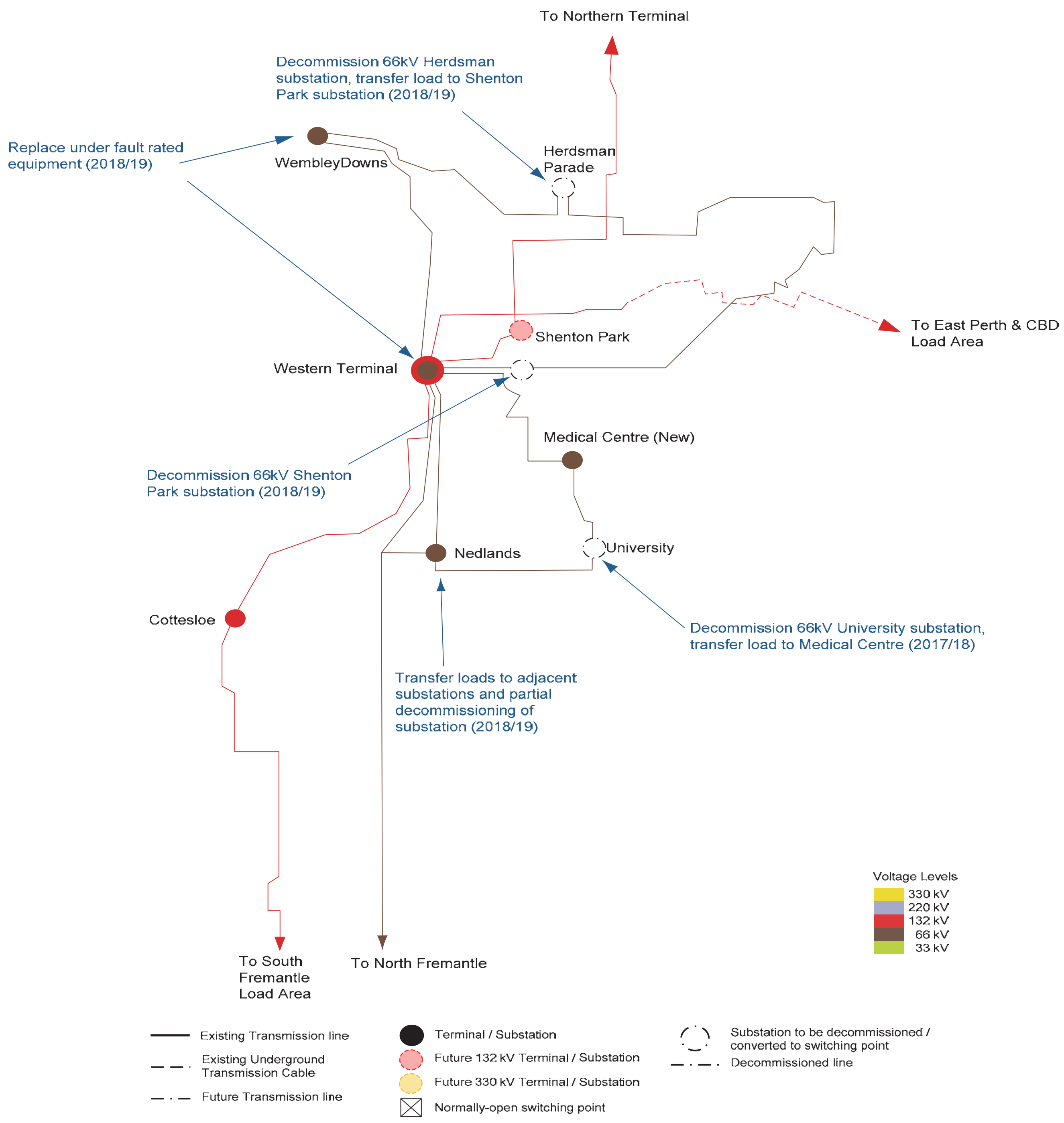
6.15.2 Western terminal load area transmission system development

The preferred transmission network strategy is shown in Figure 13. Table 21 lists the expected benefits of the planned works.

Table 21: Western terminal load area - planned works and expected benefits

Project	Benefit/s	By when
Decommission University substation following establishment of the new Medical Centre substation	Address degraded asset condition.	Summer 2017/18
Decommission the existing Shenton Park substation following establishment of the new Shenton Park substation	Address degraded asset condition	Summer 2018/19
Decommission Herdsman Parade substation following establishment of the new Shenton Park substation	Address degraded asset condition.	Summer 2018/19
Partial decommission Nedlands substation	Address degraded asset condition.	Summer 2018/19
Replace under fault rated equipment at Wembley Downs substation and Western terminal	Mitigate fault level constraints.	Summer 2018/19

Figure 13: Western terminal load area - preferred transmission solutions



6.16 Guildford load area

The Guildford load area is bound by Perth Airport in the west, the Midland area to the north and Kalamunda to the south. The area is a likely development precinct, given the large amount of undeveloped land and its proximity to the CBD.

The transmission network in this area is focused around Guildford terminal, which is connected to other major terminals including Northern terminal by 330 kV and 132 kV transmission circuits, as well as the Southern terminal by a 330 kV circuit. There are also 132 kV circuits connecting the Guildford load area to the Muja and East Country load areas. The network within Guildford load area serves the primary purpose of supplying substations connected in the 132 kV sub-transmission systems extending from Guildford terminal.

The 330 kV and 132 kV bus sections within Guildford terminal are connected via a single 490 MVA transformer that supports the majority of demand in the area. Following an outage of this transformer, Guildford load area relies on support from Northern terminal and other 132 kV injections from neighbouring load areas.

At present there is a double circuit 330 kV line between Guildford terminal and Northern terminal, one circuit is energised at 132 kV. By operating at 132 kV this defers the need for further 330/132 kV transformer capacity at Northern terminal by providing an additional 132 kV supply to Northern terminal, as well as providing support for multiple contingency conditions at both sites. While these benefits are clear, operation at 132 kV increases loading on the Guildford terminal 330/132 kV transformer and reduces use at the 330 kV level between Northern and Guildford terminals, along with increasing overall line loss. We are considering these trade-offs carefully when assessing reinforcement needs at both terminals. It is not anticipated that reinforcement will be required in the medium-term.

6.16.1 Emerging transmission network limitations within a five year period

Substation capacity

No substation capacity shortfall is forecast to emerge within the next five years.

Fault levels

No fault level issues are forecast to emerge for the transmission network in the Guildford load area within the next five years.

Thermal limits

Western Power has received a number of enquiries regarding new customer connections and load increases for existing customers in the Guildford load areas. The Forrestfield-Airport Link project is a significant transformational project in the area requiring large power supplies to support the tunnel boring machines during the construction phase.

As a result, the 132 kV Guildford to Forrestfield and Darlington to Midland Junction circuits are forecast to experience thermal overloads under certain generation dispatch conditions for the loss of either parallel circuit. To mitigate these issues, we are investigating a number of options including load transfers, line reconfiguration and special protection schemes.

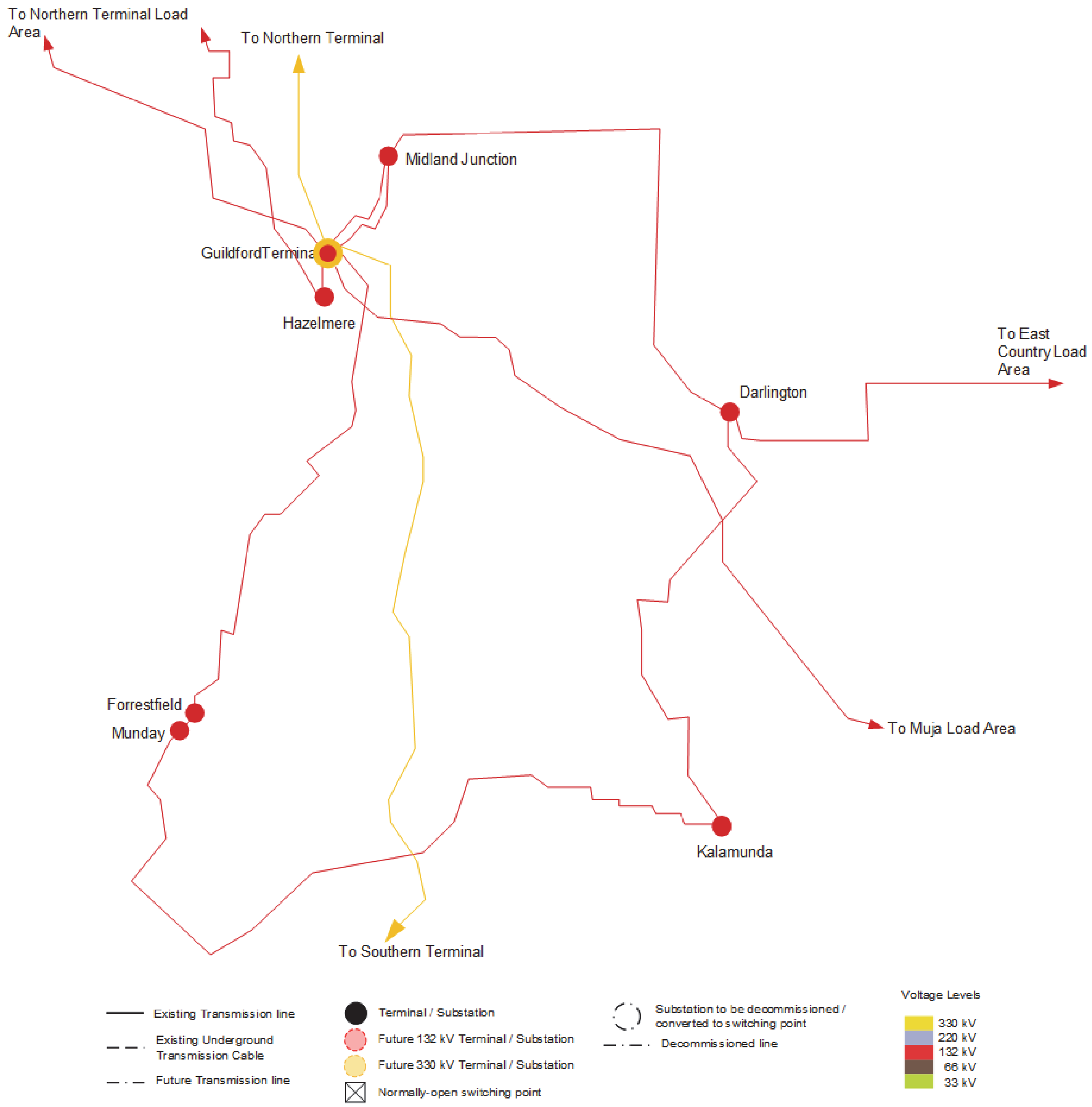
Voltage limits

No voltage stability issues are forecast to emerge within the next five years.

6.16.2 Guildford load area transmission system development

The current transmission network in the Guildford load area is shown in Figure 14 and no reinforcement is required for the next five years.

Figure 14: Guildford load area - current transmission network



6.17 Neerabup terminal load area

The Neerabup load area covers the northern most part of the Perth Metropolitan region, from Padbury and West Swan in the south to Yanchep in the north and Muchea in the east.

The network in the area is characterised by 330 kV ties with generation centres in the south of the network (Muja and Kwinana areas via Northern terminal), 330 kV connection with load centres in the North Country load area, as well as numerous 132 kV sub-transmission connections with the Northern terminal and North Country load areas. The network has evolved over time largely to support the continued high growth associated with urban development in the area.

Neerabup terminal is the focal point of the load area and is supplied by a number of generation sources through 132 kV and 330 kV transmission lines, including a peaking generation plant near the Neerabup terminal site. A single 490 MVA 330/132 kV transformer at Neerabup terminal provides bulk interconnection between the 330 kV and 132 kV networks.

The network is highly meshed with the Northern terminal and North Country load areas. This mesh can create considerable challenges, as numerous contingencies generate power system security problems under some operating conditions. In the past, development of the network within Neerabup and Northern terminal has generally followed a philosophy of retaining a meshed network. While this has provided many benefits over time, studies now indicate that splitting the networks into two relatively isolated areas offers significant advantages. Optimising the timing of this split, along with the need to address shorter term transmission and supply related issues in the area is heavily dependent on new entrant generation and large load connections in the North Country load area.

The Neerabup terminal is a strategically important terminal for the future stages of the MWEP project's southern and northern sections, which will be triggered by significant new customer load and generation connections.

6.17.1 Emerging transmission network limitations within a five year period

Substation capacity

No shortfall in substation capacity is forecast in the Neerabup load area over the next five years.

Fault levels

No fault level issues are forecast in the Neerabup load area over the next five years.

Thermal limits

We have identified that under peak demand conditions and high northerly generation, operating the Neerabup terminal 330/132 kV transformer out of service can reduce a number of post-contingent thermal overloads, without significantly compromising network security. Network Operations now operates the network in this manner in response to potential overloading events.

Under very high northerly generation, several thermal overloads emerge over the next five years. These overloads include:

- Mullaloo to Joondalup 132 kV circuit following loss of a Northern terminal 132 kV bus section and Northern terminal to Pinjar 132 kV circuit
- Joondalup to Wanneroo 132 kV circuit following loss of a Northern terminal 132 kV bus section and Northern terminal to Pinjar 132 kV circuit, although the overload is significantly less after the line uprate which was completed in 2014/15
- Pinjar to Yanchep 132 kV circuit following the loss of the Neerabup to Wanneroo 132 kV circuit and Neerabup to Pinjar 132 kV circuit,
- Clarkson to Yanchep 132 kV circuit following the loss of the Neerabup to Wanneroo 132 kV circuit and Neerabup to Pinjar 132 kV circuit.

Voltage limits

No voltage stability issues are forecast to emerge within the next five years.

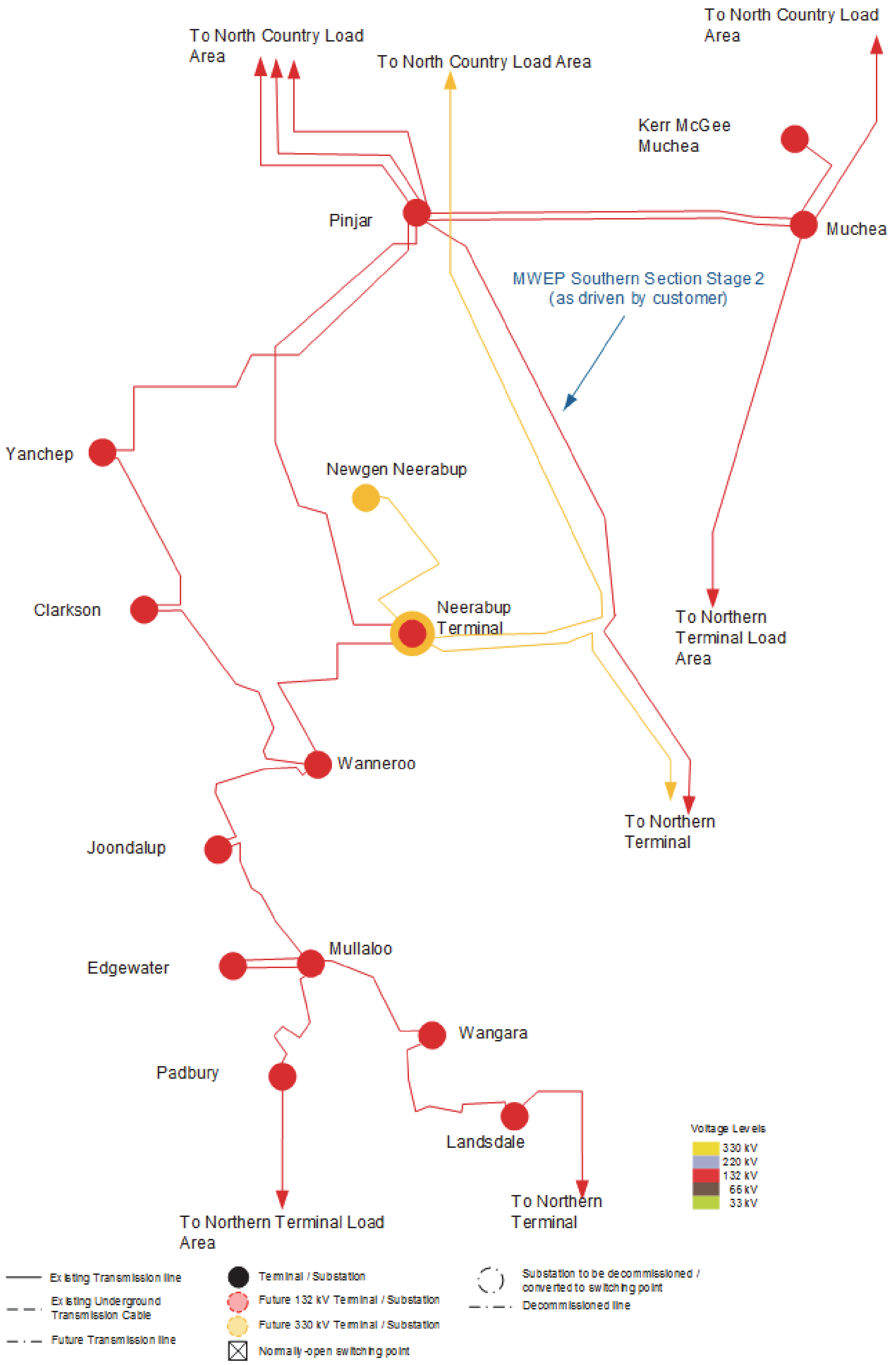
6.17.2 Neerabup terminal load area transmission system development

The preferred transmission network strategy is shown in Figure 15; Table 22 lists the expected benefits of the planned works (see Section 6.1 for additional information).

Table 22: Neerabup terminal load area - planned works and expected benefits

Project	Benefit/s	By when
Mid-West Energy Project (Southern Section Stage 2)	Accommodate increasing demand and new entrant generation connections in the North Country area; facilitate future staging of a 330 kV network north of Three Springs.	As driven by customers

Figure 15: Neerabup terminal load area - preferred transmission solutions



6.18 Northern terminal load area

The Northern terminal load area covers the northern extent of the Perth metropolitan area extending from the coast to Osborne Park and Morley in the south, North Beach in the north and to West Swan in the east.

The network in the area is characterised by strong 330 kV ties with generation centres in the south of the network (Muja and Kwinana areas) and north in the Neerabup load area, as well as 330 kV connections with large load areas supported by Southern terminal and Guildford terminal. Sub-transmission networks extend from Northern terminal at 132 kV and provide supply to numerous substations in the north metropolitan area, as well as links to neighbouring load areas including Western terminal, Guildford, East Perth and the CBD.

The bulk of supply to the area comes from the 330 kV system via two 490 MVA transformers at Northern terminal, as well as via the 132 kV links to Guildford terminal. The network within the Northern terminal area is also highly meshed with the Neerabup area. This mesh can create considerable challenges as numerous contingencies within the Northern terminal and Neerabup load areas can generate power system security challenges under some operating conditions. These load areas rely on one another in different ways, depending on operating conditions.

6.18.1 Emerging transmission network limitations within a five year period

Substation capacity

No substation capacity shortfall is forecast in the Northern terminal load area over the next five years.

Asset conditions assessments have identified 11 kV switchboards at Osborne Park, Manning Street and Yokine substations to be degraded. All of these switchboards are planned to be replaced by 2019/20.

To mitigate the risk of failure during the planning and execution phases of these replacements, we have prepared contingency plans to implement an interim solution under emergency response conditions and restore supply to the area.

Fault levels

Northern terminal is a particularly congested site with numerous 330 kV and 132 kV transmission line connections. Under current network configurations, fault levels are becoming problematic, especially at the 132 kV level. We have addressed these limitations by operating the Northern terminal and Mount Lawley substation 132 kV buses split under some operating conditions. This is intended to be an interim measure until the Neerabup and Northern terminal load areas are decoupled at the 132 kV level.

Thermal limits

No thermal issues are forecast in the Northern terminal load area over the next five years.

Voltage limits

No voltage stability issues are forecast in the Northern terminal load area over the next five years.

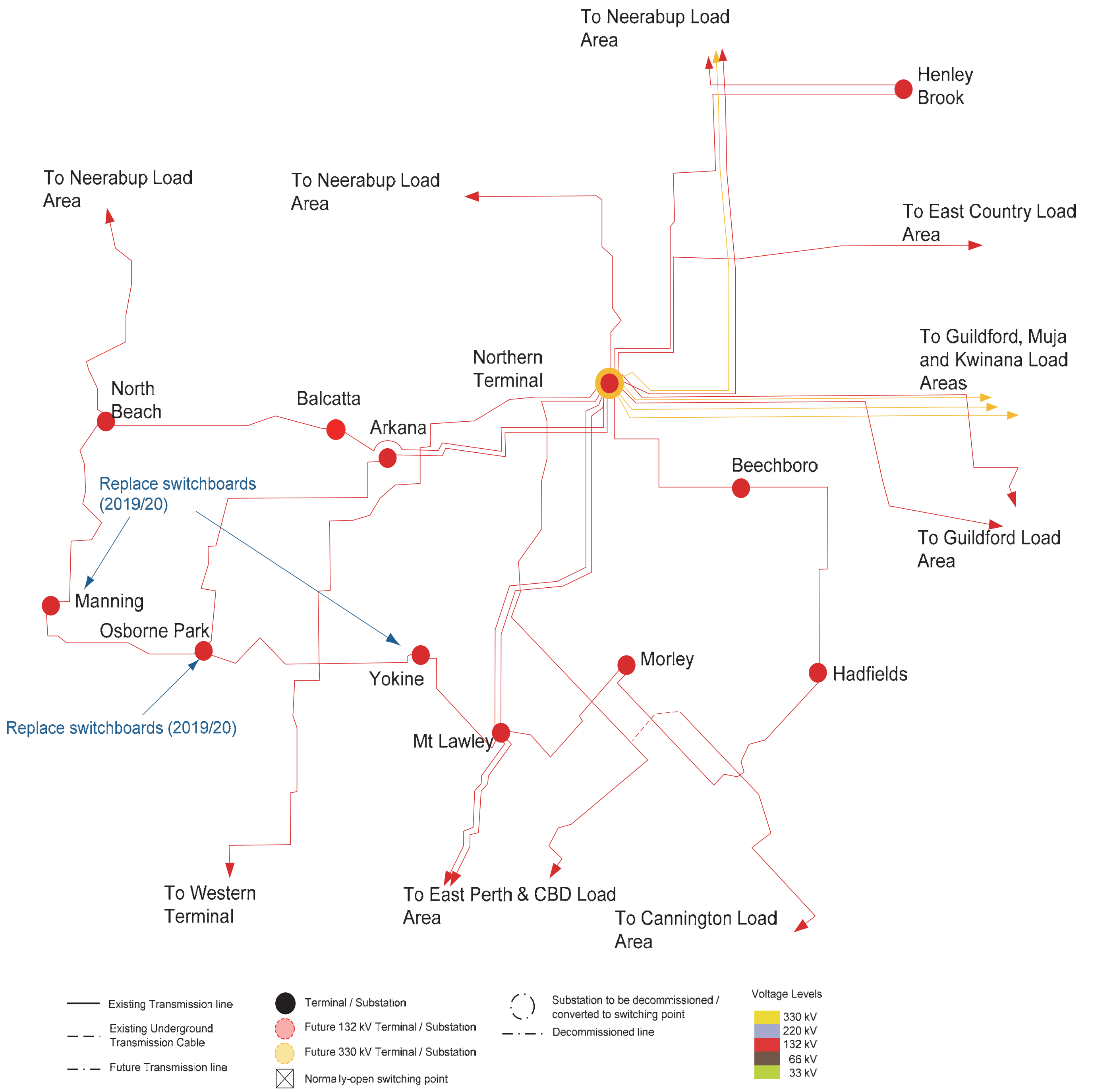
6.18.2 Northern terminal load area transmission system development

The preferred transmission network strategy is shown in Figure 16. Table 23 lists the expected benefits of the planned works.

Table 23: Northern terminal load area - planned works and expected benefits

Project	Benefit/s	By when
Replace 11 kV switchboards at Osborne Park substation	Address degraded asset condition.	Summer 2019/20
Replace 11 kV switchboards at Manning Street substation	Address degraded asset condition.	Summer 2019/20
Replace 11 kV switchboards at Yokine substation	Address degraded asset condition.	Summer 2019/20

Figure 16: Northern terminal load area - preferred transmission solutions



6.19 Load connections

6.19.1 Non-competing application thresholds

We use thresholds to help determine 'competing' load applications as part of the Applications and Queuing Policy (AQP). We consider load applications which meet the following two criteria to be non-competing for the purpose of the AQP.

» the total load must not exceed 1.5 MVA for its National Metering Identifier (NMI)
» the load application must be eligible for network tariffs RT1-RT6.

Customers on network tariffs RT1 - RT6 best represent customers that are considered part of 'natural load growth'. All load applications deemed to satisfy the test criteria will be granted firm access to the SWIN. All other load applications will be subject to further assessment to determine if they are behind network constraints.

6.19.2 Transmission load connections

We are currently progressing a number of applications for block load connections in the Eastern Region as part of a Competing Applications Group (CAG) to deliver an additional 45 MW of supply capacity to the EGF. A detailed analysis of the options has been completed, including network and non-network options. The options analysis identified the preferred option involved a suite of network augmentations and upgrades to increase the transfer capability, and we are now undertaking preliminary design activities. The project scope involves:

» installation of a third 220/132 kV transformer at West Kalgoorlie, rated at 250 MVA
» installation of dynamic voltage control devices (STATCOMs) in the EGF
» other works including distribution transfers, transmission line upgrades, control scheme modifications and protection upgrades.

Ahead of the project in-service date, we have successfully implemented interim supply arrangements for a number of customers participating in the CAG, and we continue to work with other customers to investigate interim supply arrangements, where feasible. The Economic Regulation Authority recently approved our proposal to create flexibility in the Technical Rules to consider two-phase to ground faults (rather than three-phase to ground faults) as the worst-case credible contingency. In these circumstances it is expected to increase the calculated dynamic stability limit and thus provide increased power transfer capability for load connections and/or during operational outages, while maintaining safety and power system security.

We have also commenced a review into the long-term requirements of the EGF to support future load and generator connections in the EGF and adjacent load areas. Credible options may include:

» staged development of a second transmission line to West Kalgoorlie from Guildford terminal, Wells terminal or Muja terminal
» non-network solutions, such as local generation coupled with requisite protection schemes
» other technologies, such as series compensation or HVDC.

In 2017 we will be re-engaging customers to assess level of demand, as well as engaging with potential non-network solution providers.

6.19.3 Summary of load opportunities

Over the next five years, a number of areas in the network are expected to require transmission and distribution capacity augmentations or alternative options (e.g. Network Control Services (NCS) or demand management) to provide network support capacity. Proponents who have (or are planning) generation capacity and/or demand management capacity solutions capable of providing network support are invited to contact us to discuss requirements and opportunities for provision of network support capacity. Queries should be directed to the Head of Network Planning.

Table 24 lists the key existing and emerging transmission network limitations and estimated eventual capacity shortfalls for these parts of the network within the next five years. The proposed transmission network solutions are discussed in Sections 6.4 to 6.18 and proposed distribution network solutions in Sections 7.1 and 7.2.

Generally non-network solutions are viable compared to network solutions when they are used to defer investments for a given demand requirement. Deferring the higher-cost network solution for one or more years may be an option in some cases, subject to arranging alternative solutions that at least meet the annual peak demand growth each year, rather than the eventual total capacity shortfall at the end of the five years. Annual peak demand growth rates are also listed in Table 24.

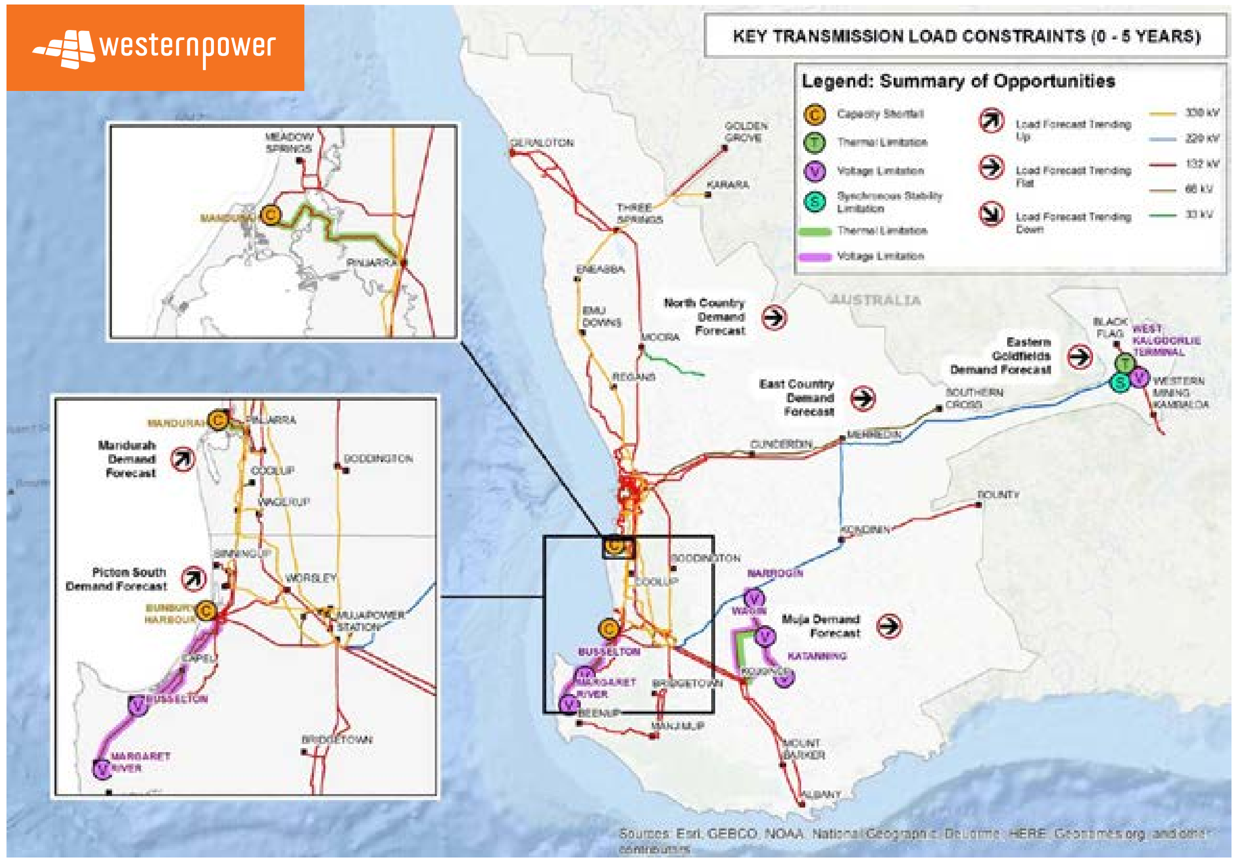
Table 24: NCS and demand management opportunities

Area of Network Limitation	Issues	Capacity Shortfall	Peak Demand Growth Rate (MVA pa)	Occurrence of Capacity Shortfall	Proposed Network Solution	Comment
Mandurah substation	Transformer capacity shortfall	< 10 MW (within 5 years)	2.92	Summer peak period between 2pm and 7pm	Refer to Section 6.9	The limitation takes into account the proposed load transfers from Mandurah to Meadow Springs following additional transformer capacity at Meadow Springs by winter 2017.
South of Picton	Voltage stability issues in the area	< 30 MW (within 5 years)	1.89	Summer / winter peak period between 2pm and 9pm	Refer to Section 6.8	The limitation is affected by a number of substations in South of Picton but Busselton and Margaret River substations have the largest contributions.
Katanning and Narrogin	Thermal overload on Kojonup to Wagin 66 kV circuit and voltage stability issues in the area	< 10 MW (within 5 years)	0.00	Summer / winter peak period between 12 noon and 8pm	Refer to Section 6.7	The limitation is affected by a number of substations in Muja 66 kV network but Katanning and Narrogin substations have the largest contributions.
Bunbury Harbour	Transformer capacity shortfall	< 15 MW (within 5 years)	2.68	Summer / winter peak period between 12 noon and 8pm	Refer to Section 6.8	-
Eastern Goldfields	Power transfer limitations	Subject to customer demand	-	Subject to assessment	Refer to Section 6.5	An Expression of Interest was released in 2014/15. Modelling and assessment of network options against the submitted responses continues.

These network demand limitations tend to occur during the annual peak demand hours on the hottest or coldest days of the year, or when a contingency occurs - e.g. when a line or transformer trips. These situations are typically infrequent throughout the year.

Figure 17 illustrates the potential locations where demand management or NCS may alleviate transmission load constraints.

Figure 17: Map of key transmission load constraints (0 to 5 years)



Please note that although additional local generation output in these load-constrained parts of the network at the times of highest load demand would support the thermal, voltage or capacity network constraints, such additional generation may, at other times, exacerbate a generation network constraint that may exist for the area.

This does not imply that a generation or demand management solution will be viable in each of the nominated network areas.

Queries should be directed to the Head of Network Planning. To consider any NCS or demand management opportunities, we are obligated to submit a request for proposal to the market.

6.20 Generator connections

6.20.1 Non-competing application thresholds

Inverter connected generators with a total installed capacity less than 1 MVA connecting to the distribution network will be deemed as not constrained and non-competing for capacity on the transmission network, as the assessed transmission network impact is low. This excludes network protection assessments, which may impact the ability to connect. Parts of our network which are deemed "at risk"[35] are provided and the capacity to connect at these sites may require further assessment.

With the dynamic nature of the network and the increasing penetration levels of distribution embedded generation with an installed capacity less than 1 MVA, we will review this threshold on a routine[36] basis and communicate any change directly to key industry bodies. For further details, please contact the Access Solutions Manager at customer.connection.services@westernpower.com.au

6.20.2 Transmission generator connections

We are currently progressing applications for generator connections, particularly in the Northern Region, Southern Region and East Country Region.

Generator access to our network and dispatch under the Wholesale Electricity Market (WEM) are currently unconstrained. The Government's plans to regulate the network under the National Electricity Law, including the adoption of a constrained network access regime under the National Electricity Rules, has been deferred. As discussed at the December 2016 Industry Briefing Forum[37], it is intended that the endorsed WEM reforms and the implementation of AEMO's market systems will continue progress. While it must be confirmed during the design phase, it is expected that the implementation of AEMO's market systems, including a constrained dispatch engine, will facilitate new generator connections on a constrained basis beyond mid-2019, and prior to the introduction of full constrained access. It is also understood that the adoption of a full constrained access regime will continue to be pursued, with a potential commencement date of mid-2022, at the end of our next Access Arrangement period, subject to confirmation by the Government in 2017. We expect a constrained dispatch engine to apply a least-cost dispatch approach according to generator bid price and contribution to network constraints.

Given the deferral of constrained access reforms, we have been working with the Australian Energy Market Operator (AEMO) and the Public Utilities Office (PUO) to develop an interim solution option, termed Generator Interim Access (GIA) which will support new generator connections in a timely manner (by late 2018).

The objectives of the approach are to:

» curtail new generators (only) to maintain system security (i.e. not affect the contracted unconstrained access of existing generators)
» have a dispatch objective consistent with that proposed under the EMR's WEM reforms, i.e. a proxy for least-cost dispatch using a 'minimise-runback' approach based on contribution to network constraint (or coefficient).

6.20.3 Summary of generation opportunities

A number of areas in the network have limited capacity to support new generator connections on a reference service without significant network augmentation. In such cases, non-reference connections may be considered as described in the preceding section, whereby the new generator output is curtailed during those (generally short) periods of time where network capacity is limited.

Figure 18 illustrates key network limitations which may limit capacity available to non-reference generators. Typically a new generator would undertake a detailed assessment to

[35] At risk substations are limited in accommodating a significant capacity (≤2.5 MW) of inverter connected distribution embedded generators. These zone substations include Coolup (CLP), Kellerberrin (KEL), Kojonup (KOJ), Mundaring Weir (MW), Southern Cross (SX), Beenup (BNP), Mount Barker (MBR) and Wagin (WAG).
[36] Routine impact assessments will be conducted on a quarterly basis for the first year of implementation and performed on annual basis thereafter.
[37] https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Industry-Briefing-Forum-20-December-2016.pdf

quantify the level of congestion and potential limitations on power output, such as through market simulation studies.

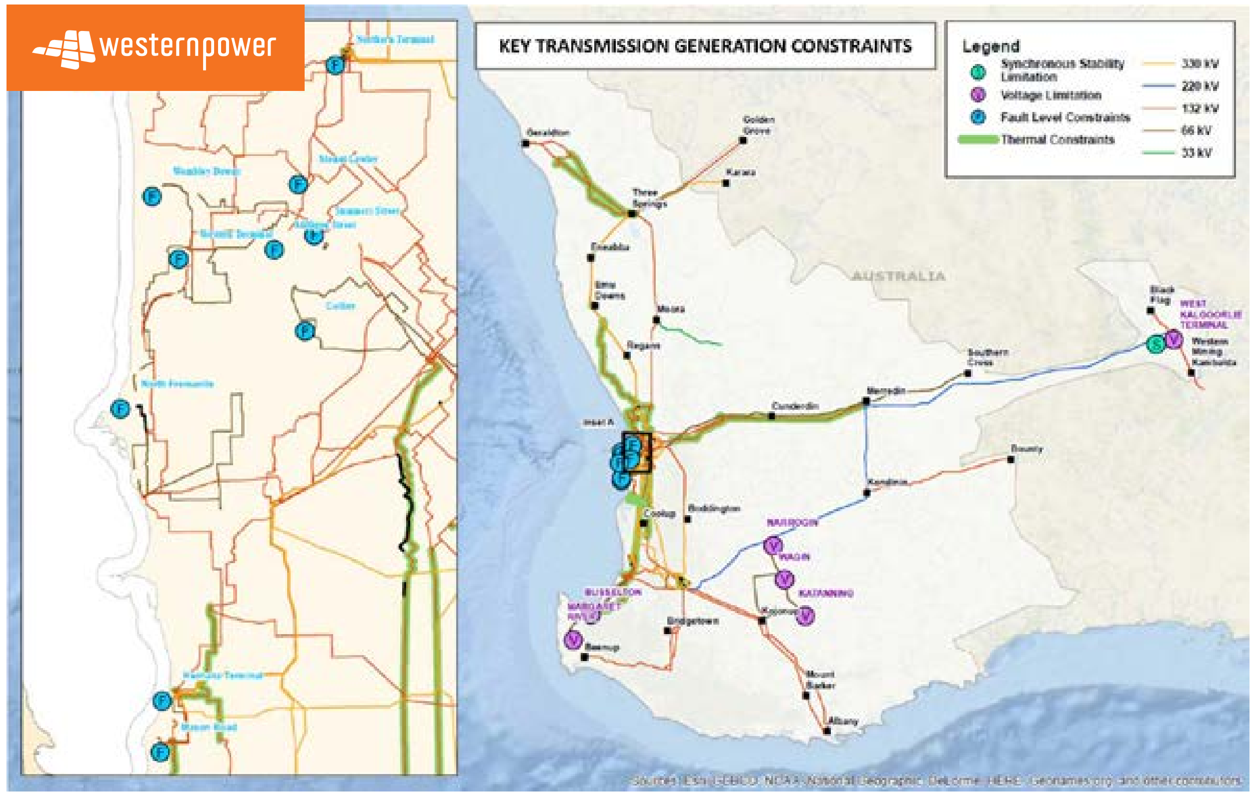
Key limitations illustrated in Figure 18 which may impact new generator connections are:

» north country 132 kV capacity for flows from south to north
» north country 132 kV capacity for flows from north to south limited by
  ¤ 132 kV network capacity in the adjacent Neerabup load area
  ¤ 132 kV network capacity between Mungarra and Three Springs, including the Three Springs bus bar for generation connected north of Three Springs
  ¤ 132 kV network capacity between Three Springs and Pinjar for generation connected south of Three Springs
  ¤ 132 kV network capacity between Three Springs substation and Three Springs terminal
» south country 132 kV capacity for flows from south to north
» east country 132 kV capacity for flows from east to west
» east country 132 kV capacity for flows from west to east
» fault level limitations in the Kwinana and Northern terminal load areas.

Other site specific considerations may include:

» transmission and distribution system fault levels
» ancillary service requirements
» steady-state performance
» dynamic performance
» power quality
» protection coordination
» impact on system capability.

Figure 18: Map of key transmission generation constraints (0 to 5 years)



7. DISTRIBUTION SYSTEM AND DEVELOPMENTS

7.1 Metro planning region

The Metro planning region extends as far north as Guilderton, as far south as Dawesville and east to Chidlow.

The Metro planning region is divided into four smaller planning sectors naturally defined by the Swan River and the Darling Escarpment. These are the Metro Central Business District (Metro CBD), Metro North, Metro East and Metro South.

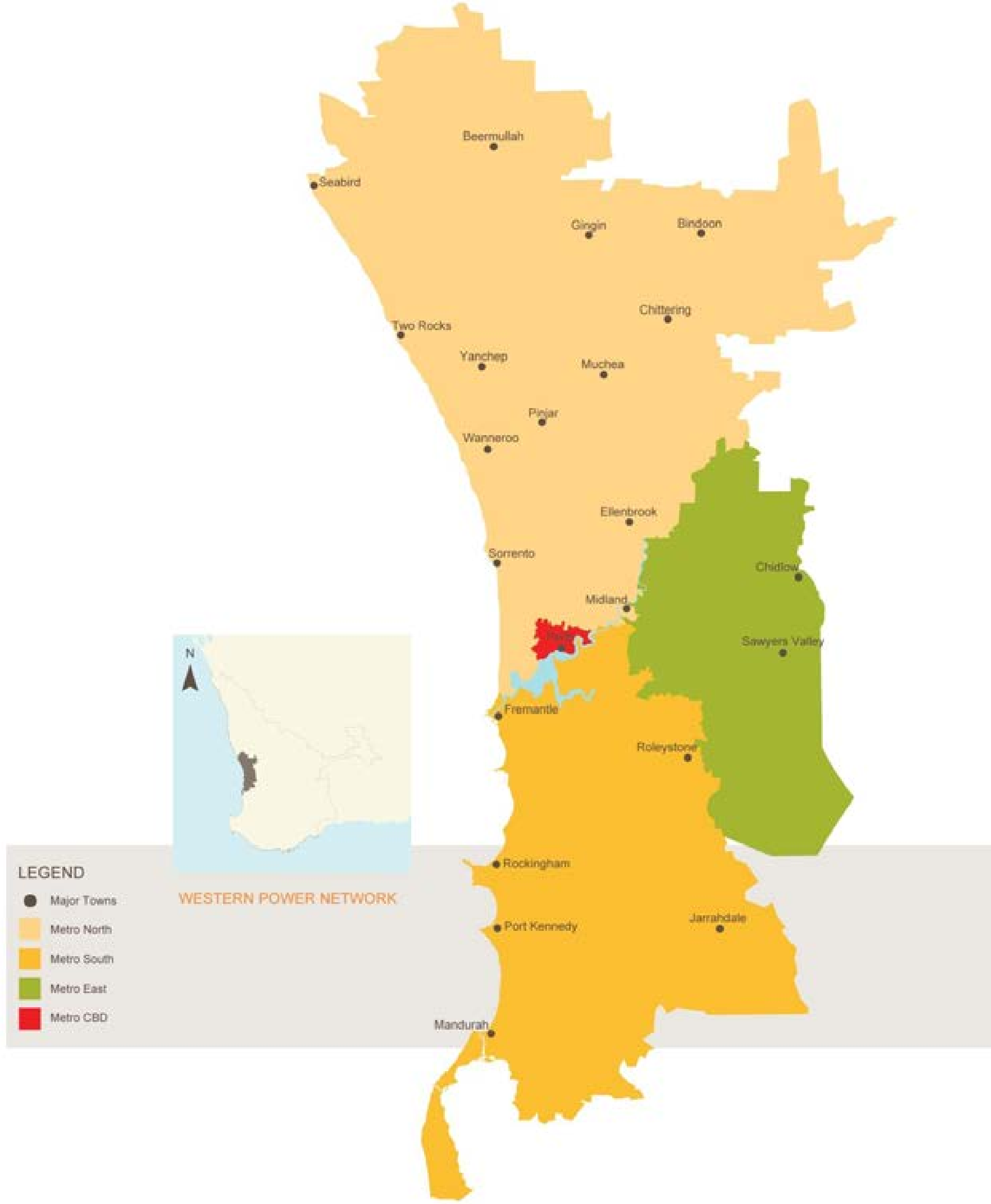
Figure 19 shows the geographic boundaries of these planning sectors. The Metro CBD is defined as its own planning sector due to different load characteristics and planning requirements.

The Metro planning region is a mix of overhead and underground distribution networks. Overhead distribution networks dominate the outer fringes, but as subdivisions on the outskirts expand over time, the proportion of underground network will continue to increase.

The overhead networks on the outer fringes tend to be long feeders affected by voltage constraints and reliability issues. This is mainly in the north of the Metro planning region and, to a lesser extent, in the south of the Metro planning region, where the mean feeder lengths are particularly long.

Much of the underground and overhead network within the urban fringes experience thermal constraints as they accommodate load growth and new developments. This is compounded by restrictions on feeder exit cable ratings caused by feeder congestion around the zone substations.

Figure 19: Metro planning sectors



7.1.1 Metro CBD (11 kV) planning sector

The outer boundaries of the Metro CBD planning sector are growing steadily mainly through residential infill, as developers stay close to the CBD. These areas are supplied primarily from Joel Terrace in the east, North Perth to the north and Cook Street to the west.

Towards the central region of the Metro CBD planning sector, bound by the Swan River, the load is primarily commercial developments, office space and high density residential developments.

Hay Street and Milligan Street substations supply Perth's CBD with interconnections to the surrounding Cook Street, Wellington Street and Forrest Avenue substations.

The Technical Rules specify a higher security of supply standard for the loads in the Perth CBD region, compared to other distribution networks within our network. The relevant criterion requires spare capacity on the feeder network so in the event of a fault, load can be automatically restored via the interconnections with minimal customer outage, even during high load periods.

The feeders in the Metro CBD planning sector operate at 11 kV, are relatively short because of the high load density and suffer from thermal constraints, primarily caused by feeder congestion out of the zone substation. In addition, clustering of large loads throughout the Metro CBD planning sector makes it difficult to transfer load effectively. This forms part of the challenge for future planning and new large customer block load connections.

Strategic plans for this area include new infrastructure such as pit and duct systems, as well as additional ducts where suitable opportunities arise (such as the Elizabeth Quay and Perth City Link development projects). Stage 2B of ducts installation at Perth City Link is due to be complete by summer 2017/18.

To address the N-2 issue, a new 132 kV cable between Hay Street and Milligan Street substations is proposed for completion by summer 2019/20.

Furthermore, 11kV switchboard assets at both these substations are degraded. Plans exist to replace the Hay Street switchboards by 2020/21, with the Milligan Street switchboards planned to be replaced beyond the five year horizon.

Given the lead times of these projects, we are investigating opportunities to transfer load between zone substations to manage the reliability of supply until the projects are complete. Non-network solutions such as demand management techniques are also being considered to defer capital investment, where it is economical to do so.

A number of assets within the CBD area, particularly at Forrest Avenue substation, are operating at or beyond end of their service lives and are degraded. We are investigating opportunities to replace these assets, with one option involving the construction of a new 132kV CBD substation to facilitate the decommissioning of 66kV substations in the area.

Table 25: Metro CBD - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions[39]
Milligan Street Hay Street Wellington Street Forrest Avenue Joel Terrace Cook Street North Perth	City of Perth City of Vincent City of Bayswater City of Stirling Town of Cambridge City of Subiaco	Perth Metropolitan

[38] Department of Regional Development

Table 26: Metro CBD - committed works and expected benefits

Project	Benefit/s	Area/s	By when
CBD: Perth City link Install Ducts Stage 2B	Minimise excavation to cater for future cables installation as part of Perth City Link development plan.	CBD	Summer 17/18

Figure 20: Metro CBD 11 kV planning sector

7.1.2 Metro North planning sector

The Metro North planning sector is bound by the Swan River and CBD planning sector in the south, by the Vines development in the east, Gingin in the north and Guilderton in the west.

There are a number of distribution voltages in the Metro North planning sector, these are a legacy of the network's development over a number of decades.

This sector is divided into the following voltage planning clusters:

» Metro North 6.6 kV
» Metro North 11 kV
» Metro North 22 kV (A)
» Metro North 22 kV (B).

The 22 kV network is divided into two clusters, as there are limits to the number of interconnections between zone substations in cluster (A) and cluster (B). The primary reason behind this is the natural physical barrier of Whiteman Park.

Metro North 6.6 kV planning cluster

The Metro North 6.6 kV cluster has a diverse array of HV metered loads that include commercial developments around Claremont, Claremont Quarter, Graylands, King Edward Memorial hospital, Venue West sports centre, Irwin Barracks, Subiaco Waste Water Treatment Plant and Metronode.

The residential areas are mature from a load development perspective, however new residential and commercial developments will create additional load as part of the Claremont Oval and Subiaco redevelopments.

The distribution voltage in this cluster is 6.6 kV with a mix of overhead and underground distribution network. The 6.6 kV operating voltage means that each feeder is capable of supplying much less power than higher voltage (11 kV and 22 kV) feeders. The 6.6 kV feeder network is short and well interconnected with zone substations in the planning cluster.

We have recently completed the new Medical Centre 132 kV substation, now energised at 66 kV. This facilitates the necessary load transfers from the old Medical Centre and University substations, as well as permitting 132 kV transmission network upgrades over a number of years. The new substation is intended to cater for the decommissioning of the old Medical Centre and University substations, both of which have assets in degraded condition. The bulk of the existing load from old Medical Centre and University substations have been upgraded to 11 kV and supplied by new Medical Centre substation.

We have recently completed the new Shenton Park 132 kV substation. This will cater for load growth and accommodate the decommissioning of the existing degraded Shenton Park and Herdsman Parade substations by 2018/19. We have committed to upgrade existing load from old Shenton Park and Herdsman substations to 11 kV and connected them to new Shenton Park substation in Winter 2017.

A number of assets in Nedlands substation have been assessed to be in degraded condition. By the end of 2017, the distribution networks for all Western terminal zone substations, except Nedlands substation, will be operating at 11 kV voltage. As a result, the Nedlands distribution network will be islanded without sufficient distribution transfer capacity to cater for a contingent event. We will address the issue by upgrading the Nedlands network to 11 kV and resupplying the Nedlands load from adjacent substations by 2017/18.

Therefore, it is expected the entire Metro North Cluster load will be operating at 11 kV by 2017/18.

Given the lead times of projects, we are investigating other opportunities to transfer load between substations to manage the reliability of supply until the new substations are complete. Non-network options such as demand management techniques were found to be non-viable in this case.

Figure 21: Metro North planning sector - voltage planning clusters

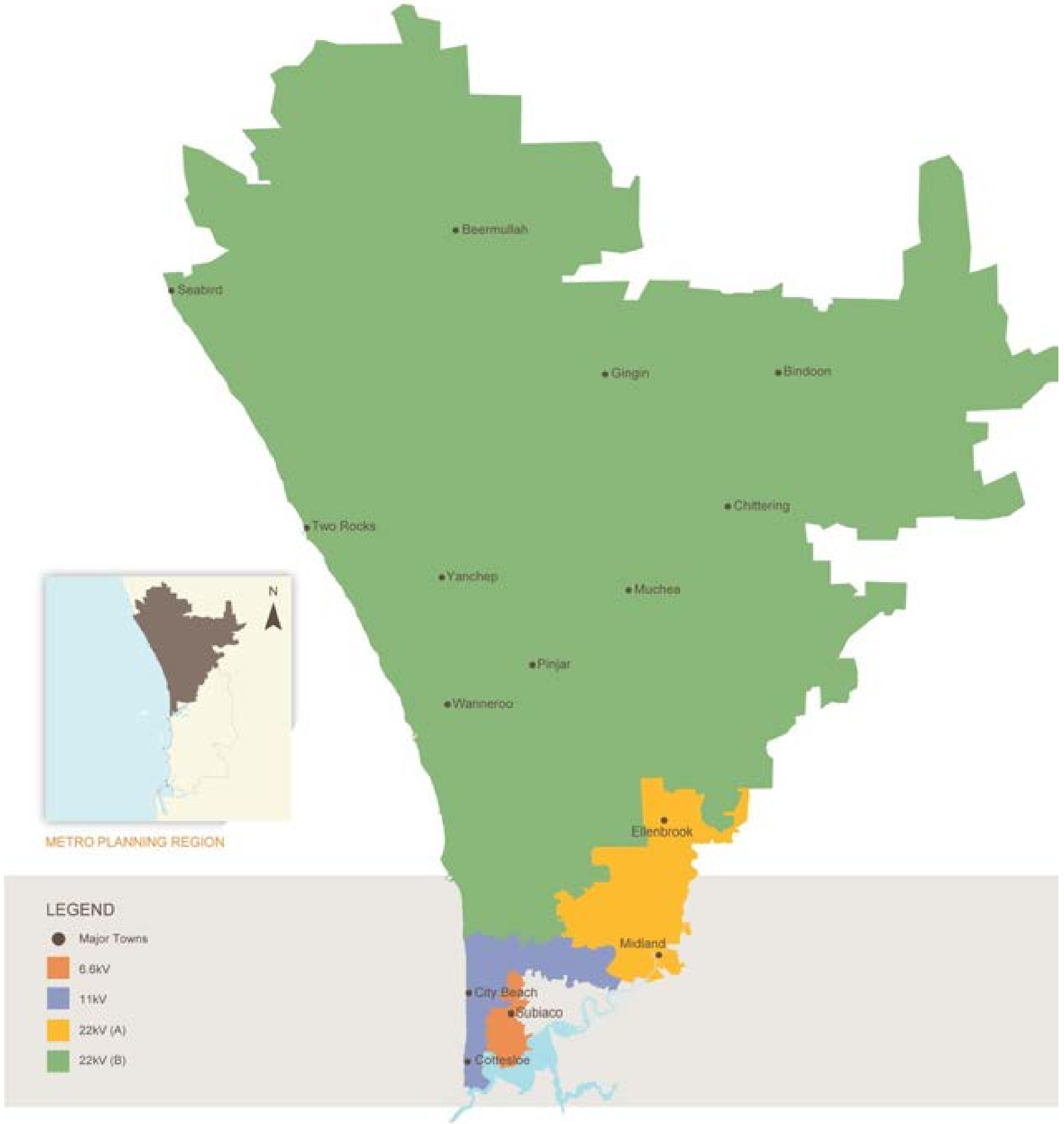


Table 27: Metro North 6.6 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Herdsman Parade Nedlands Shenton Park Medical Centre University	City of Stirling City of Subiaco City of Nedlands	Perth Metropolitan

Table 28: Metro North 6.6 kV - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Medical Centre & University: Conversion of existing Medical Centre and University distribution network to 11 kV	Accommodate increasing demand and assets at the end of their service lives.	Sir Charles Gardiner Medical Centre, Nedlands	Summer 2016/17
Shenton Park: Decommissioning of existing Shenton Park substation	Address degraded asset condition.	Shenton Park	Summer 2018/19
Herdsman: Decommissioning of Herdsman Parade substation	Address degraded asset condition.	Herdsman Parade substation, Wembley	Summer 2018/19
Nedlands: Convert to 11 kV and reinforce network	Address degraded asset condition.	Nedlands	Summer 2017/18

Figure 22: Metro North 6.6 kV planning cluster

Metro North 11 kV planning cluster

The Metro North 11 kV cluster supplies mainly residential load with small pockets of commercial development and a concentrated industrial area at Osborne Park. The residential areas in some areas are at a relatively mature stage of development (particularly the eastern areas), whereas areas closer to the Perth city centre and the coast are yet to mature with in-fill developments. These developments are showing an increase in residential density particularly in areas close to employment and transport nodes.

The distribution voltage in this cluster is 11 kV, with a mixture of overhead and underground distribution networks.

There are a number of interconnections between the contiguous 11 kV substations within this cluster. However there are some capacity constraints on the distribution network that limit the ability of these interconnections to transfer significant portions of load between substations.

The distribution network is limited by thermal constraints on distribution exit cables caused by cable congestion due to restrictive cable exit routes in front of zone substations. There are also sections of lower rated cables and conductors throughout the network. These limitations can reduce the amount of load transferrable between substations during outages and maintenance.

The 11 kV switchboards at Osborne Park, Manning Street and Yokine substations are degraded and require replacement. Based on these limitations, we have prepared contingency plans to mitigate the risk of failure during the planning and execution of these staged replacements.

Options to improve feeder congestion out of the Osborne Park and Yokine substations to improve feeder capacities are currently being investigated.

There are currently no committed capacity expansion projects in this planning cluster.

Table 29: Metro North 11 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Cottesloe	City of Stirling	Perth Metropolitan
Manning Street	City of Vincent	
Morley	Town of Cambridge	
Osborne Park	City of Bayswater	
Wembley Downs	City of Nedlands	
Yokine	Town of Claremont	
	Shire of Peppermint Grove	
	Town of Mosman Park	
	City of Fremantle	
	Town of Cottesloe	

Figure 23: Metro North 11 kV planning sector

Metro North 22 kV (A) planning cluster

The Metro North 22 kV (A) planning cluster covers a large portion of the Metro North planning sector and has a diverse array of loads.

The eastern portion of the area captures the beginnings of the Swan Valley, with a high intensity agricultural of loads. Significant industrial loads are located at both Malaga and Bassendean, supplied from the Malaga and Hadfields substations respectively, in the southern portion of the cluster.

Remaining areas in the south-east and north-east of the Metro North 22 kV (A) planning cluster are predominantly residential loads. The north-east portion (the Ellenbrook area) and the south-east portion (the Caversham area) are currently experiencing rapid residential growth. There are new developments in these areas and an expectation that development will continue well into the next couple of years.

This 22 kV cluster is separated from the Metro North 22 kV (B) planning cluster because of a reduction in the number of useful interconnections to transfer load between clusters. Whiteman Park is also a natural barrier with relatively low load density reducing the need to create interconnections between the two planning clusters.

The Hadfields network to the south of the Metro North 22 kV (A) planning cluster is partially bound to the east by the Swan River with a few limited interconnections to the Metro East planning sector (see section 7.1.4). Additional interconnection limitations exist on the west side of the Hadfields network, as this network is adjacent to the Morley distribution network that operates at 11 kV.

Options to reduce feeder peak loading are being considered for Beechboro and Hadfields substations, potentially requiring reinforcements that improve the capacity of associated networks.

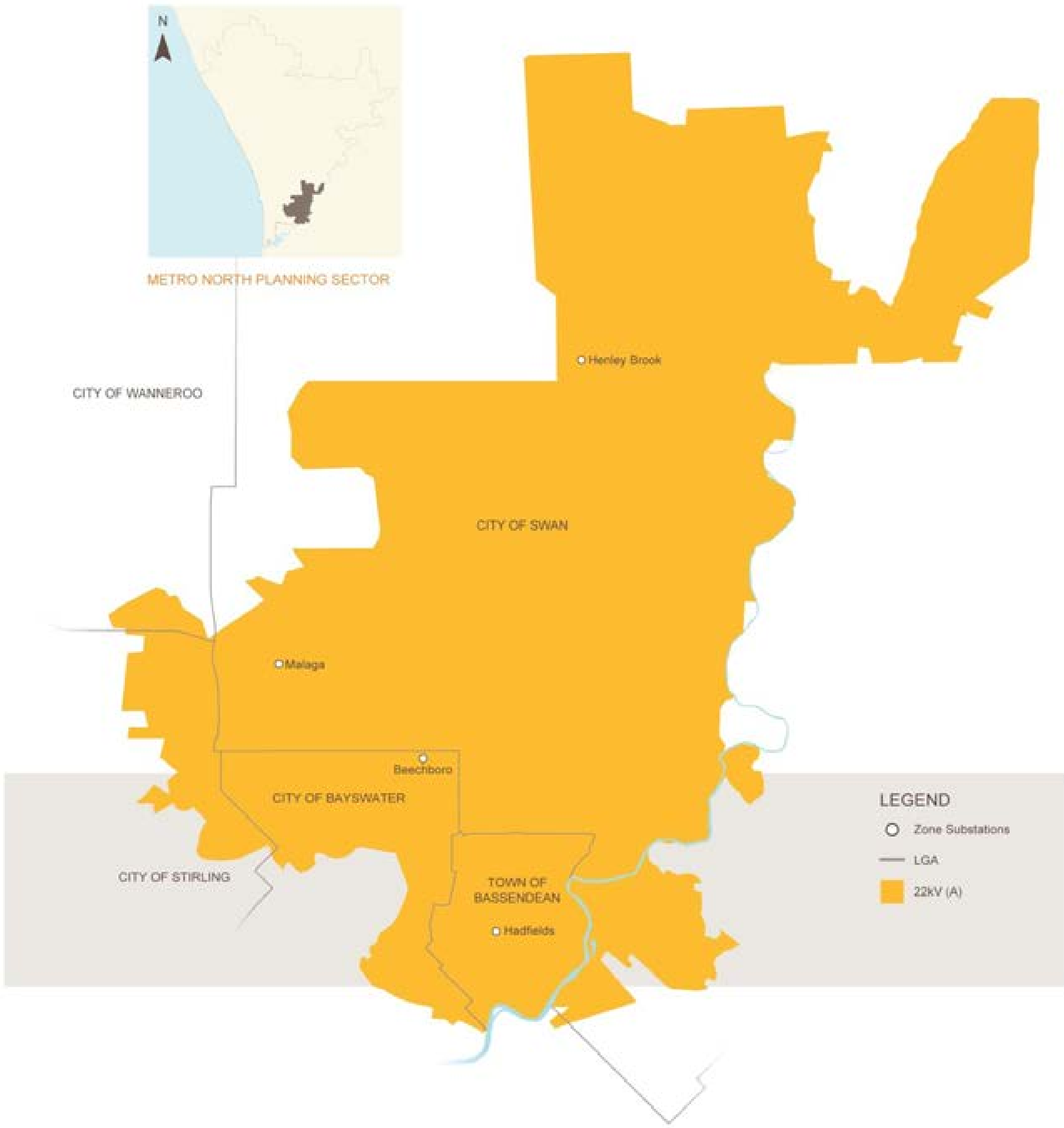
On the overhead network, thermal constraints are more prevalent due to lower rated sections of feeder backbone. Options are being investigated to balance the overall cost with the benefits realised, these include upgrading sections of the overhead network with larger conductors and undergrounding sections of the network.

There are currently no committed capacity expansion projects in this planning cluster.

Table 30: Metro North 22 kV (A) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Beechboro Hadfields Henley Brook Malaga	City of Bayswater Town of Bassendean City of Swan City of Stirling City of Wanneroo	Perth Metropolitan

Figure 24: Metro North 22 kV (A) planning cluster



Metro North 22 kV (B) planning cluster

The Metro North 22 kV (B) planning cluster covers most of the Metro North planning sector and supplies a diverse range of loads. The outer fringes of this cluster are mainly semi-rural loads with long overhead feeders that are voltage constrained. The zone substations supplying these areas are Muchea and Regans 22 kV.[39] Yanchep substation has a single feeder running north is also supplying a similar type of load.

These semi-rural feeders from Yanchep, Muchea and Regans 22 kV substations are characterised by their long length and voltage regulators installed along the feeder to maintain acceptable voltage levels at the customer end. Pole-top capacitor banks on these types of feeder networks provide voltage support.

The remaining substations in this planning cluster supply a mix of residential, commercial or large industrial loads. Capacities of these networks are established by the thermal ratings of the power transformer and feeders.

The coastal areas and southern portion of the planning cluster are mainly residential, with pockets of commercial development. The majority of the residential developments closer to Perth City are reasonably mature. New subdivisions between Yanchep and Two Rocks will likely increase demand on the coast north of Quinns Rocks.

There are significant industrial loads at the Wangara/Gnangara Industrial Area and the Neerabup industrial area is slowly taking shape as a significant future industrial hub in this cluster.

Like the Metro North 22 kV (A) planning cluster, this cluster experiences thermal constraints in the distribution network. There are limitations on the feeder backbones and exit cable congestion is evident at the older substations in this catchment, namely North Beach and Mullaloo.

The mitigation of the feeder constraint depends on the forecast load growth. Upgrading the weak backbone is costly and generally achieves minimal capacity improvement, so a new feeder is likely to be more effective.

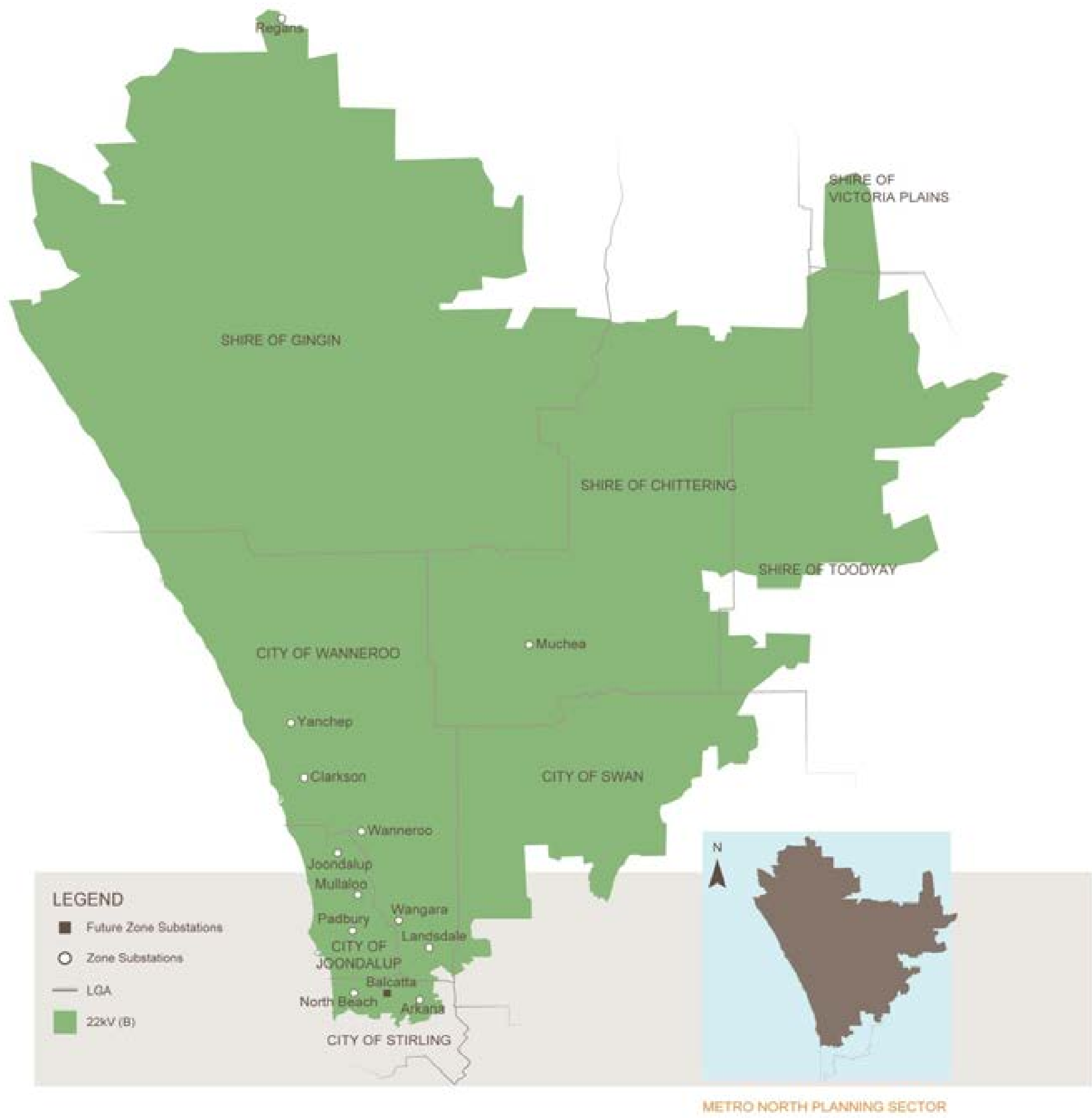
There are currently no committed capacity expansion projects in this planning cluster.

Table 31: Metro North 22 kV (B) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Arkana	City of Stirling	Perth Metropolitan
Balcatta	City of Stirling	Wheatbelt
Clarkson	City of Joondalup	
Joondalup	City of Wanneroo	
Landsdale	City of Swan	
Muchea	Shire of Chittering	
Mullaloo	Shire of Toodyay	
North Beach	Shire of Gingin	
Padbury	Shire of Victoria Plains	
Regans 22 kV[40]		
Wanneroo		
Yanchep		
Wangara		

[39] Regans substation also has a 33 kV distribution network, which is discussed in Section 7.1.4.

Figure 25: Metro North 22 kV (B) planning cluster



7.1.3 Metro South planning sector

The Metro South planning sector is bound by the Swan River to the north, the Metro East planning sector to the east and the Country South planning region in the south.

There are different distribution voltages in the Metro South planning sector, legacies of the network development over a number of decades.

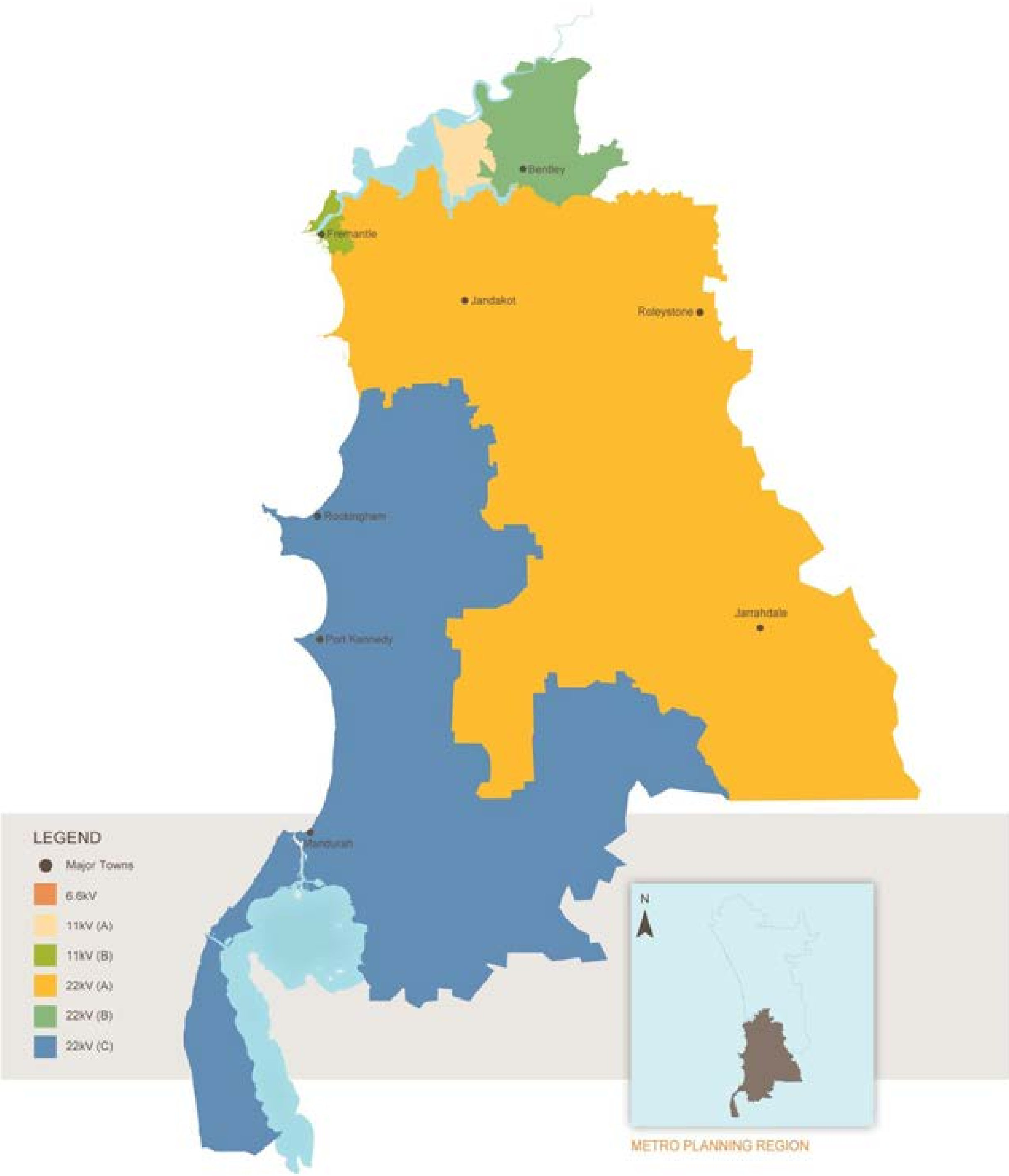
The Metro South planning sector is extensive, covering areas with diverse characteristics. For planning purposes, it is divided into the following voltage planning clusters, based on their ability to transfer load between zone substations:

» Metro South 11 kV (A)
» Metro South 11 kV (B)
» Metro South 22 kV (A)
» Metro South 22 kV (B)
» Metro South 22 kV (C).

The 11 kV network is divided into two clusters, as there are no interconnections between their substations.

The 22 kV network is also divided into three clusters, as there is a limit to the number of interconnections between their zone substations. The primary reason is the natural boundaries created by the Canning River and areas of undeveloped land.

Figure 26: Metro South planning sector showing voltage planning clusters



Metro South 11 kV (A) planning cluster

The area is primarily residential, with older dwellings away from the Swan and Canning Rivers. High density residential developments are occurring at transportation corridors and areas with river views. There are some commercial loads in the area, with the majority in the South Perth precinct.

There are no projected substation capacity shortfalls in this cluster over the five year outlook.

The distribution voltage in this cluster is 11 kV, with a mix of overhead and underground distribution networks. Restrictions on the distribution feeder network are caused by thermal constraints on the feeder exit cables and feeder backbones.

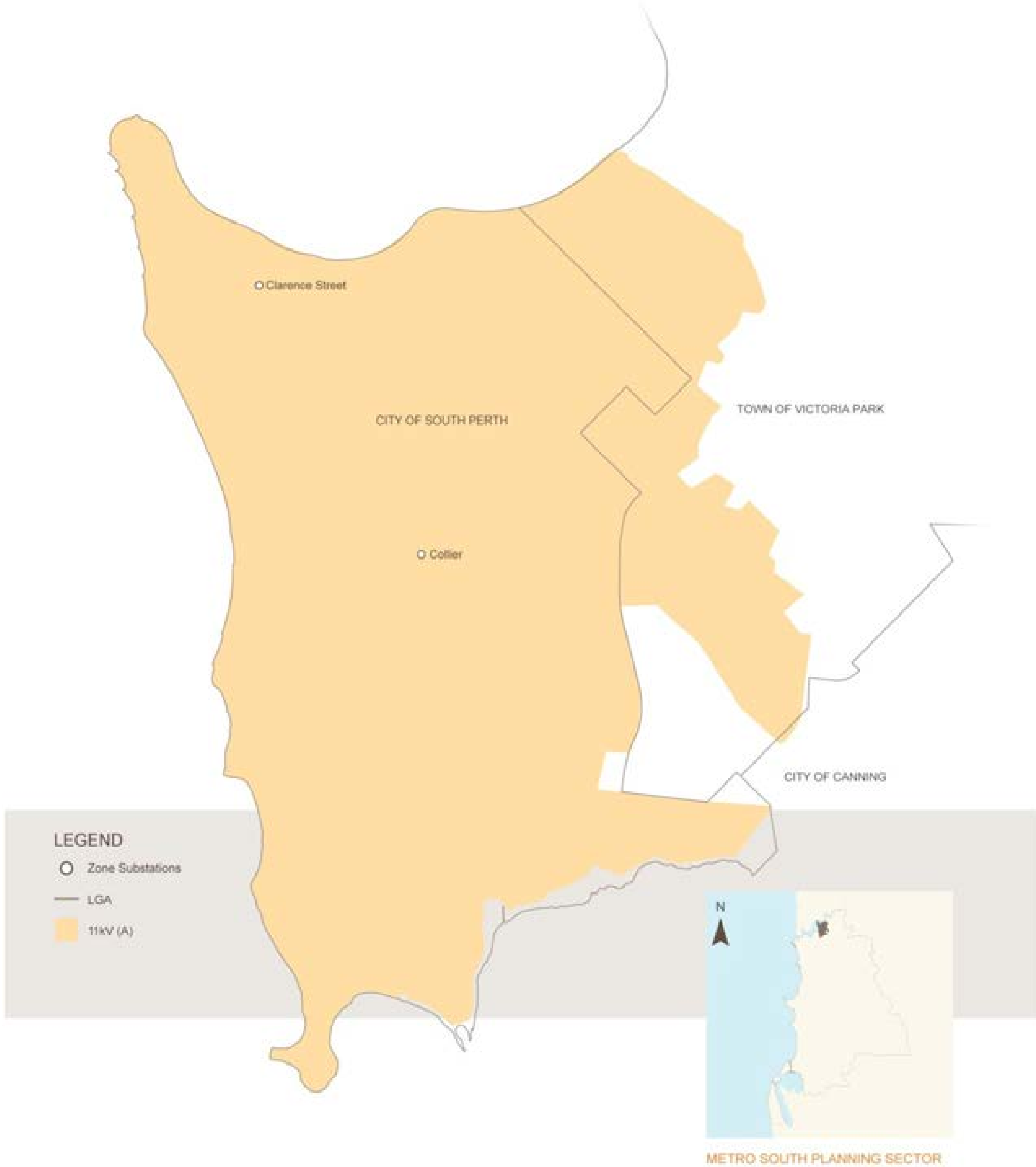
The longer term strategy for this cluster is being refreshed, one option may involve a staged upgrade of the 11 kV feeder network to 22 kV. The benefit of this conversion will be better interconnections that aid reliability and the increase in the overall capacity of the network. The upgrade will most likely involve converting the networks to 22 kV and transferring part of the load to Bentley substation, which is contiguous to Collier substation.

There are currently no committed capacity expansion or voltage conversion projects in this planning cluster.

Table 32: Metro South 11 kV (A) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Clarence Street Collier	City of South Perth Town of Victoria Park City of Canning	Perth Metropolitan

Figure 27: Metro South 11 kV (A) planning cluster



Metro South 11 kV (B) planning cluster

The combined capacity of the zone substations in this cluster is adequate to support the forecast growth beyond the next five years.

The distribution voltage in this cluster is 11 kV with a large proportion of the network underground.

The cluster contains a mixture of residential loads on the fringes, industrial loads on North Quay and Victoria Quay and commercial activities around Fremantle City.

Load growth is generally moderate, as loads have matured and new developments are rare in the Fremantle city area. Higher density residential dwellings are being developed where river and ocean views are available.

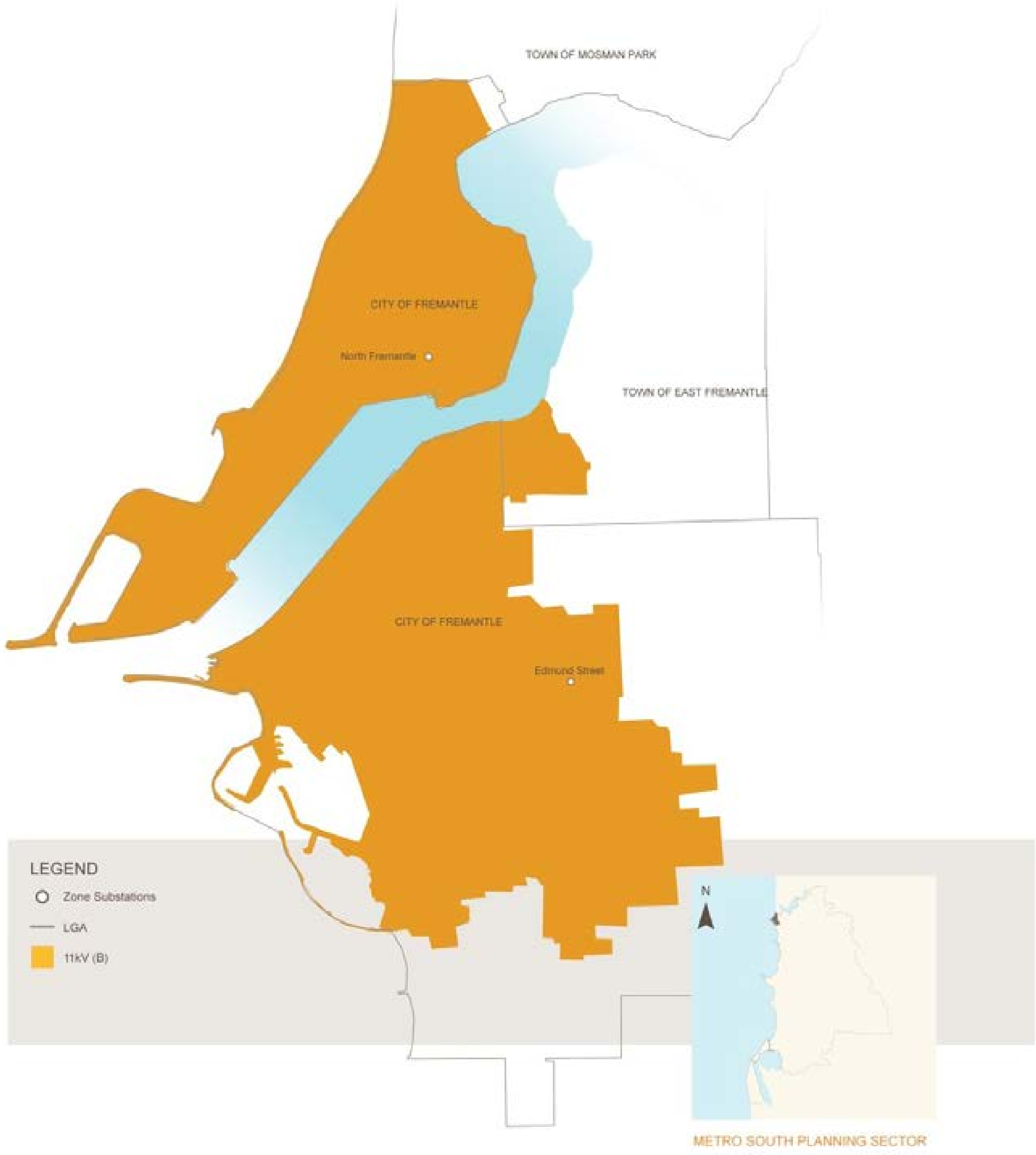
Table 33: Metro South 11 kV (B) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Edmund Street North Fremantle	City of Fremantle Town of East Fremantle	Perth Metropolitan

Table 34: Metro South 11 kV (B) - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
North Fremantle: De-energise and resupply by adjacent distribution network	To resolve the transmission cables issues.	Fremantle, East Fremantle, North Fremantle	Winter 2017

Figure 28: Metro South 11 kV (B) planning cluster



Metro South 22 kV (A) planning cluster

The Metro South 22 kV (A) planning cluster covers a large portion of the Metro South planning sector and has a diverse array of loads.

The south-east outer fringes of this cluster mainly comprise semi-rural developments with agricultural and commercial loads near the town sites of Armadale and Byford. Pockets of these areas close to transport corridors are being developed into residential housing with supporting residential activities, creating commercial loads.

Areas adjacent to the Swan and Canning Rivers are older, developed residential areas with new high density residential developments south of Fremantle City.

Significant industrial load exists in Henderson and Canning Vale industrial areas and there is potential for significant expansion to the Henderson Industrial Park and the Jandakot Airport area. Other large industrial parks in the cluster include O'Connor, Myaree, Maddington,[40] Forrestdale, Bibra Lake, Jandakot and Cockburn Central.

Asset condition issues exist at Myaree, O'Connor and Australian Paper Mills substations. The long term strategy for the area involves a transition to 132kV voltage and replacement of these transformers with reconfigurable HV units (66 kV and 132 kV).

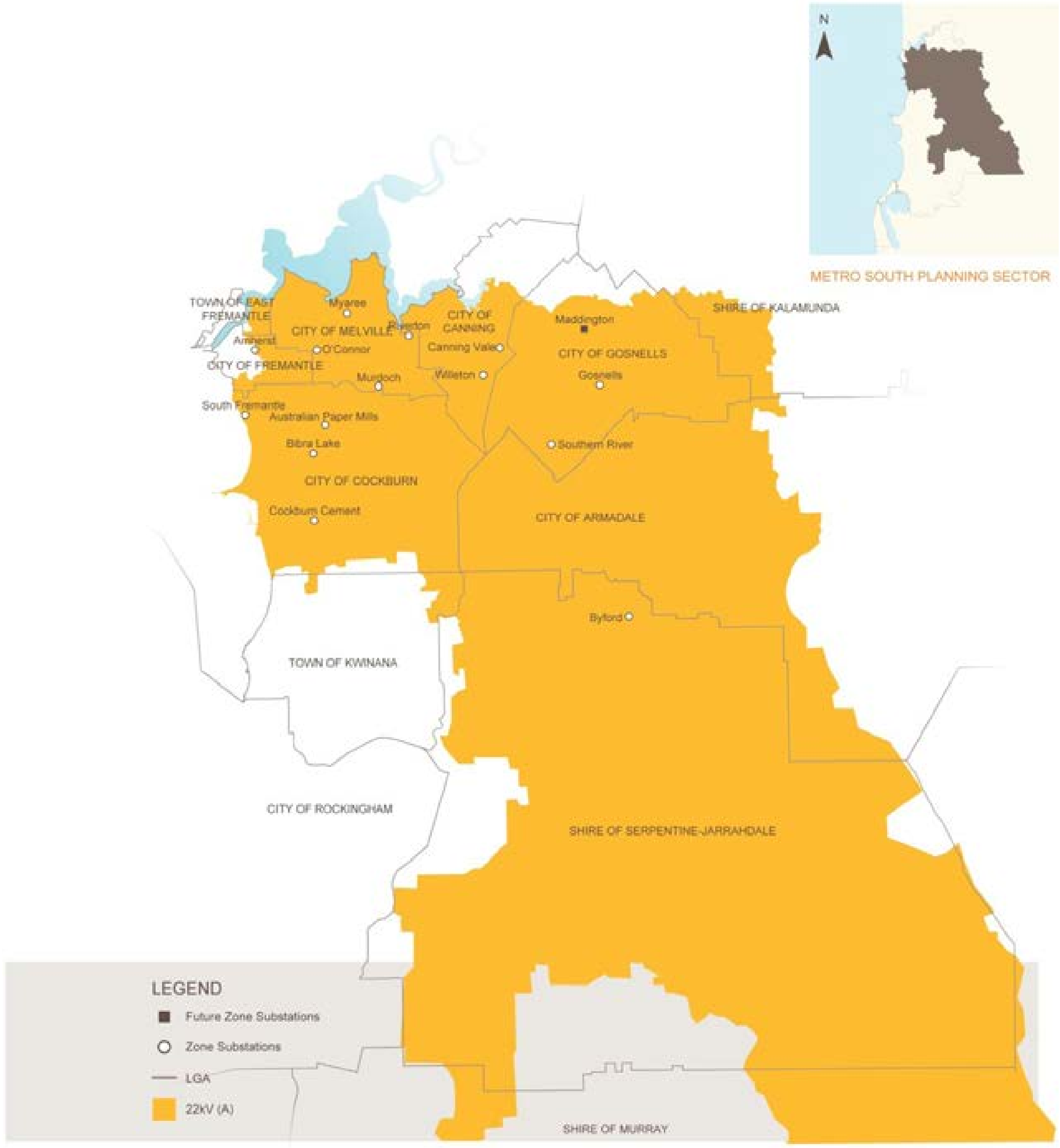
There are currently no committed capacity expansion projects in this planning cluster.

Table 35: Metro South 22 kV (A) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Amherst	City of Fremantle	Perth Metropolitan
Australian Paper Mills	Town of East Fremantle	
Bibra Lake	City of Melville	
Byford	City of Canning	
Canning Vale	City of Gosnells	
Cockburn Cement	City of Armadale	
Gosnells	City of Cockburn	
Maddington	City of Kwinana	
Murdoch	Shire of Serpentine-Jarrahdale	
Myaree	Shire of Murray	
O'Connor	Shire of Kalamunda	
Riverton	City of Rockingham	
South Fremantle 22 kV		
Southern River		
Willetton		

[40] Half of the Maddington industrial area is supplied by the Metro South 22 kV (B) planning cluster.

Figure 29: Metro South 22 kV (A) planning cluster



Metro South 22 kV (B) planning cluster

The cluster is bordered by the Swan River in the north, the Metro South 11 kV (A) planning cluster to the west, the Perth International Airport and Metro East planning sector to the east, and the Canning River and Metro South 22 kV (A) planning cluster to the south.

There are some interconnections with the Metro East planning sector, however these cannot transfer significant portions of load as there are spans of lower-rated conductor at the end of the feeder near the interconnections.

Similarly, there are some interconnections with the Metro South 22 kV (A) planning cluster through the Maddington Industrial Area, however there are also lower-rated conductors at the feeder ends reducing the ability to transfer significant portions of load. The Canning River also creates a natural boundary between the two clusters, restricting additional interconnections.

The loads in this cluster are dominated by the industrial loads at both Welshpool and Kewdale Industrial Areas, with newer industrial areas being developed at Belmont and Maddington.

The remaining load in this cluster is mostly residential with pockets of commercial activity centres. The residential loads are mature, particularly closer to the Perth CBD. New developments tend to be higher density and close to transport corridors. New residential developments are generally infill and new subdivisions are rare, as there is no large, vacant or semi-rural land to develop.

Plans are being developed to resolve the feeder thermal constraints by either replacing the lower-rated assets or installing new feeders to offload the heavily loaded feeders. This augmentation is likely to be performed in the near future to reinforce the feeder network at Tate Street and Kewdale substations.

There are currently no committed capacity expansion projects in this planning cluster.

Table 36: Metro South 22 kV (B) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Belmont	Town of Victoria Park	Perth Metropolitan
Bentley	City of South Perth	
Kewdale	City of Belmont	
Rivervale	City of Canning	
Tate Street	Shire of Kalamunda	
Welshpool	City of Gosnells	
	City of Bayswater	
	City of Swan	

Figure 30: Metro South 22 kV (B) planning cluster

Metro South 22 kV (C) planning cluster

This cluster covers the coastal strip from north of Rockingham to Naval Base, consisting of heavy industrial loads and supporting light industrial and commercial activities. The Kwinana Industrial Area has been earmarked for significant expansion and redevelopment. The cluster consists primarily of high growth residential loads from Rockingham in the north to Dawesville in the south. Higher densities of residential dwellings are found around the Rockingham and Mandurah city centres along with commercial developments.

The distribution voltage in this cluster is 22 kV, with a mix of overhead and underground distribution networks. The most significant issues requiring management are thermal constraints caused by either feeder exit cable congestion or lower rated feeder backbone sections. The feeder thermal constraints are expected to be resolved by either upgrading existing assets or installing new feeders.

We recently installed a third transformer at Mason Road substation allowing future load growth, new customer connections and the decommissioning of British Petroleum substation. British Petroleum substation assets are degraded and the substation has been de-energised. The existing substation load has recently been transferred to Mason Road substation facilitating the decommissioning of the British Petroleum substation to be complete by 2020/21.

As discussed in Section 6, substation capacity shortfalls are anticipated at Mandurah and Meadow Springs over the five year outlook. To relieve these limitations we are installing additional transformers at Meadow Springs and Mandurah substations and planning a series of load transfers by summer 2017/18 and summer 2019/20 respectively.

A tender award process is already underway to select the preferred supplier/s to deliver an end to end non-network option with the aim of deferring the installation of additional transformer capacity at Mandurah substation for at least a year. Given the lead times of the projects we are investigating other opportunities to transfer load between substations to manage the reliability of supply until the new reinforcements enter service.

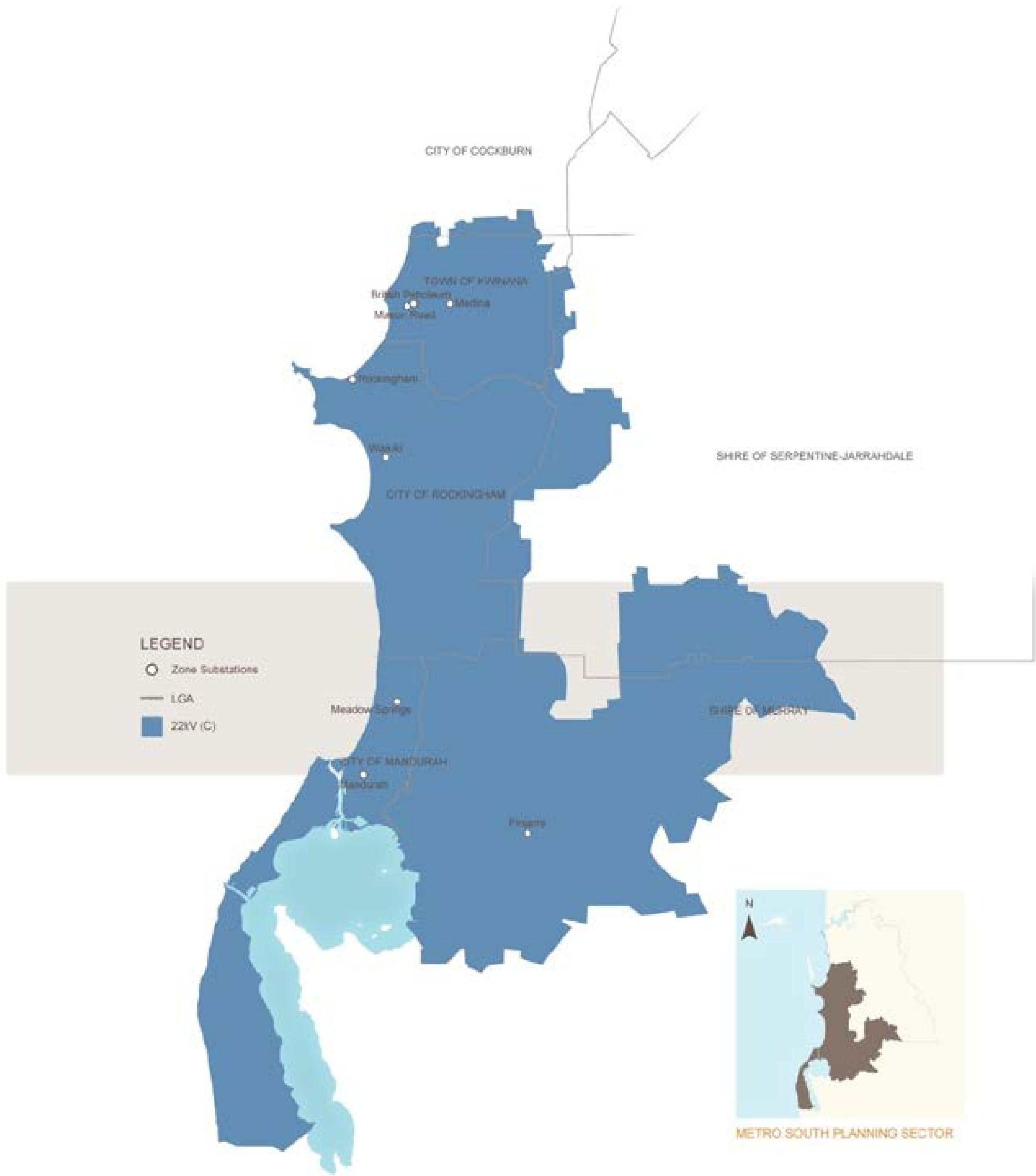
Table 37: Metro South 22 kV (C) - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Mandurah Mason Road Meadow Springs Medina Pinjarra Rockingham Waikiki	City of Cockburn City of Kwinana City of Mandurah Shire of Murray City of Rockingham Shire of Serpentine-Jarrahdale	Peel Perth Metropolitan

Table 38: Metro South 22 kV (C) - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Meadow Springs: Install 3rd transformer	Improve reliability and supply constraints at Mandurah and Meadow Springs substation.	Kwinana	Summer 2017/18

Figure 31: Metro South 22 kV (C) planning cluster



7.1.4 Metro East planning sector

The Metro East planning sector is bordered by the Swan River in the north-west and extends north towards Avon Valley National Park, east towards Boononging, south towards Canning Dam and south-west towards Wattle Grove and west towards the Perth International Airport.

The Metro East sector is separate from the Metro North and Metro South planning sectors, as it has different characteristics and requirements for future growth. This catchment covers the eastern hills areas of Perth and adjoins the Country East planning region; however no feeders interconnect the two planning regions.

This sector is divided into the following voltage planning clusters, based on their ability to transfer load between zone substations:

» Metro East 6.6 kV
» Metro East 22 kV

Metro East 6.6 kV planning cluster

This cluster supplies facilities for the Water Corporation's operations at Mundaring Weir and is not interconnected with the surrounding area. The load growth is constant and is dominated by the Water Corporation's facilities, with Mundaring Weir the cluster's only zone substation.

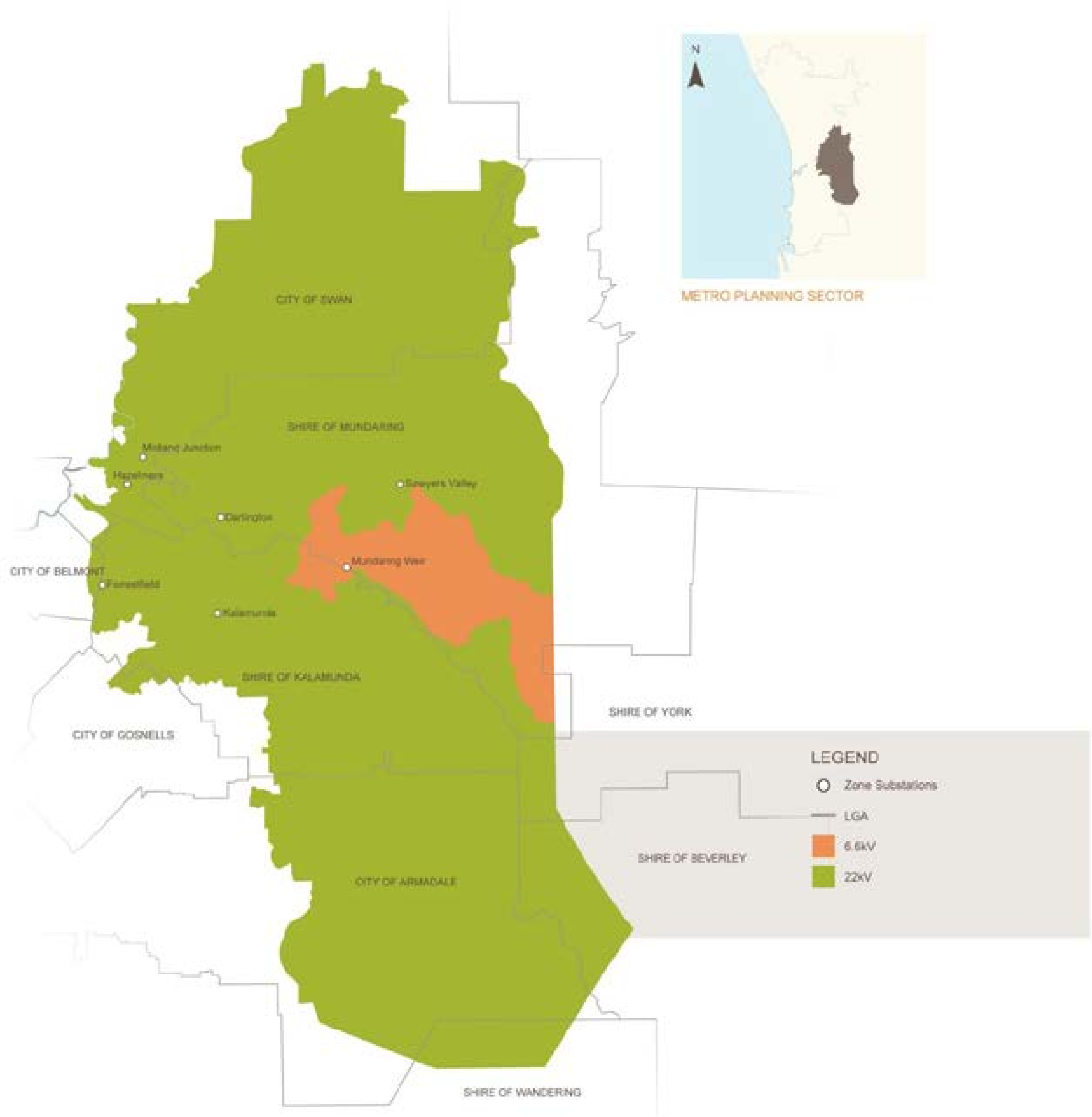
The Mundaring Weir network is islanded and has no distribution transfer capacity and a number of substation assets are degraded. Planning is underway for the conversion of the remaining 6.6 kV load to 22 kV and load transfers to the adjacent Sawyers Valley substation, which will facilitate the decommissioning of the Mundaring Weir substation by 2019/20.

There are currently no committed capacity expansion projects in this planning cluster.

Table 39: Metro East 6.6 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Mundaring Weir	Shire of Mundaring	Perth Metropolitan

Figure 32: Metro East planning sector



Metro East 22 kV planning cluster

Although the Metro East planning cluster overlaps the Shires of York, Beverley and Wandering, the feeder network does not yet extend this far.

The Metro East 22 kV planning cluster supplies a range of loads. There are heavy industrial loads in the east near the Perth International Airport and residential and commercial precincts at Midland, Forrestfield and Kalamunda. This planning cluster consists of a high intensity of agricultural load around Middle Swan and low density residential development and supporting commercial activities covering the outskirts of the cluster, particularly through the eastern portion of the Darling Escarpment. The remaining land is undeveloped parklands, reserves or state forest.

The distribution voltage in this cluster is 22 kV with a mixture of overhead and underground distribution network.

The main supply issues in this area are the thermal and voltage constraints of distribution feeder assets. Feeder exit cable de-rating is caused by congestion at Darlington, Kalamunda and Midland Junction substations. This is not an issue at the new Forrestfield and Hazelmere substations thanks to improved designs to feeder routes.

In terms of voltage constraint, feeders from Sawyers Valley and Darlington substations have long distribution overhead networks. Capacitor banks and voltage regulators are often required to provide voltage support.

There are currently no committed capacity expansion projects in this planning cluster.

Table 40: Metro East 22 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Darlington Forrestfield Hazelmere Kalamunda Midland Junction Sawyers Valley Munday	City of Armadale City of Belmont Shire of Beverley City of Gosnells Shire of Kalamunda Shire of Mundaring City of Swan Shire of Wandering Shire of York	Perth Metropolitan

7.2 Country distribution planning

The Country Planning Region of the network extends north to Kalbarri, south to Albany and east to Kalgoorlie-Boulder. It is divided into four smaller regions:

» Country North
» Country South
» Country East
» Country Goldfields

The Country Planning Region consists of long and short rural networks with some urban networks in more populated areas. Overhead distribution networks dominate, with underground generally only found in urban town centres. However, all new residential and commercial subdivisions must incorporate underground distribution networks, so the proportion of underground networks is growing.

The overhead rural networks consist of long feeders, often exhibiting voltage constraints with significant voltage control infrastructure. Rural feeders are subject to lower reliability service standards due to their exposure to environmental conditions, number of assets that could fail and cause an outage, travelling distance for maintenance crews and limited interconnections with other feeders.

Underground and overhead networks within the urban areas (of the country region) frequently exhibit thermal constraints that may impinge on load growth and new developments, especially for higher growth coastal communities.

Figure 33: Country planning region

7.2.1 Country North region

The Country North region extends northwards from the outer Perth metropolitan region to Kalbarri. The planning region also extends into the northern areas of the Wheatbelt, around 150 km east of the coast. There are currently eight substations feeding the Country North region.

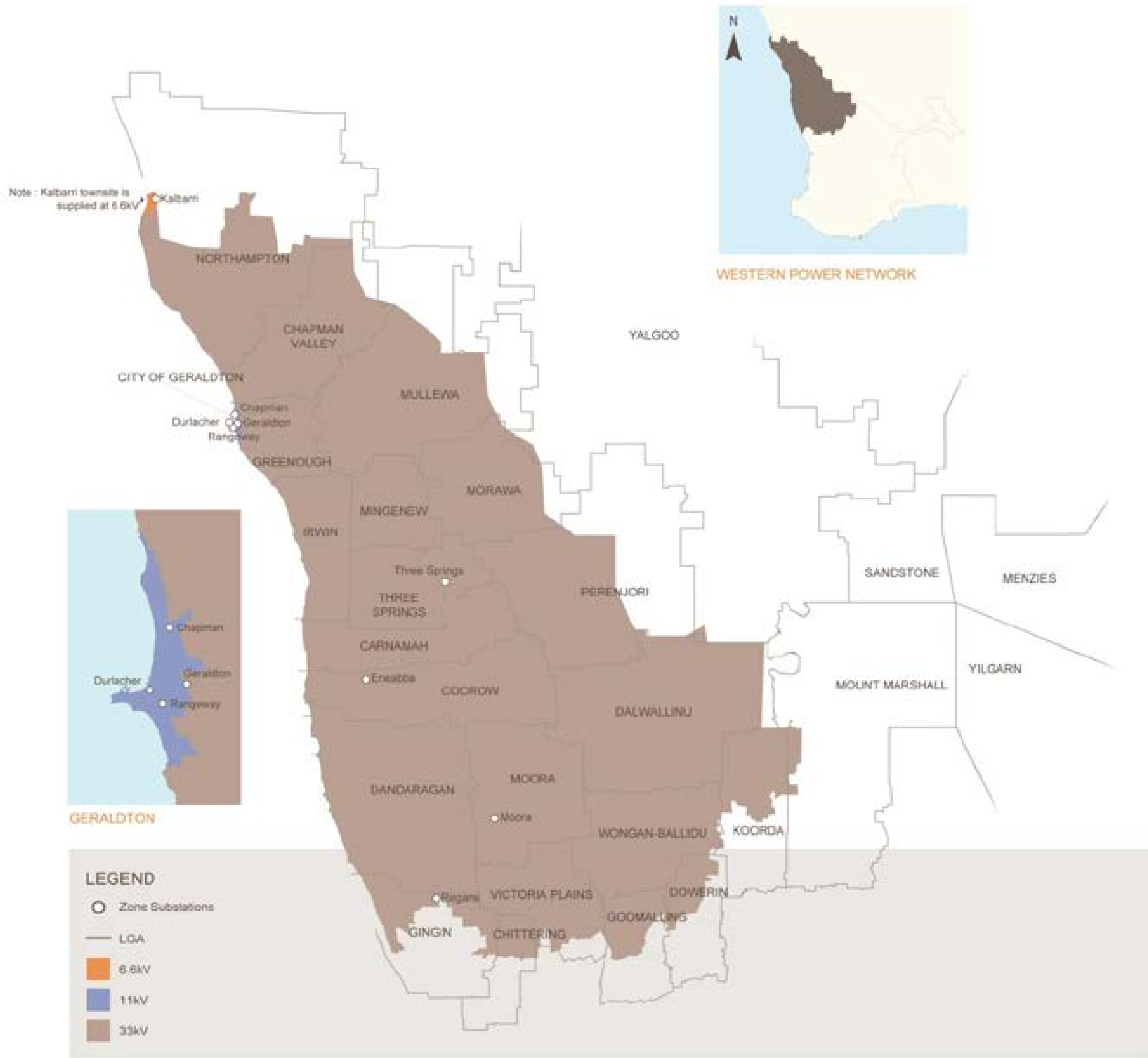
In general, the networks supplying the Country North region are radial, overhead power lines supplying the networks at 33 kV. This region is divided into three distinct areas: Northern Wheatbelt, Coastal and Geraldton-Greenough.

The Northern Wheatbelt has long, lightly loaded overhead networks. The loads are generally small and dispersed for broad acre agricultural purposes, except for the towns of Moora and Three Springs, which are shorter and more heavily loaded rural networks. The Kalbarri town network is unique, as it is connected to the Western Power network and supplied via a step down transformer at 6.6 kV.

The coastal area has long, lightly loaded overhead networks. Generally, users are relatively small and dispersed for broad acre agriculture purposes. The towns of Cervantes, Jurien Bay, Eneabba and Dongara are supplied by these networks and are more heavily loaded. There is also some larger industry in this area, which includes mining loads around Eneabba.

The Geraldton-Greenough area has moderate load density. The majority of the networks are overhead, except for the newer 11 kV networks in Geraldton. The networks supply residential and industry loads servicing the horticulture, fishing, port, mining and tourism activities. These loads generally peak in summer, driven by water pumping, air conditioning or cool storage.

Figure 34: Country north planning region



Country North 33 kV planning cluster

The 33 kV network in Country North supplies mining and industrial loads, as well as many rural centres. The network is predominantly overhead. Development has slowed in the past few years coinciding with the downturn in the global economy.

Major developments expected to influence the cluster include:

» completion of Indian Ocean Drive[41]
» WA State Government 'Super-town' scheme
» future development of the Oakajee Port
» Mid West Energy Project
» development of new magnetite mines and expansion of the Geraldton Port.

Load transfers between zone substations in Country North are limited by voltage constraints and few interconnections between long distribution power lines.

We have a project underway that is delivering a staged load transfer from the ageing Durlacher substation (supplied by the Geraldton terminal) to Rangeway substation by 2018/19. This means we can decommission assets within the Durlacher substation. To accommodate the additional load we are proposing a third transformer at Rangeway substation and to reconfigure the congested distribution exits.

We have negotiated curtailable connection arrangement agreements with some customers. The forecast load requirements have dropped, which in turn has deferred the need for a new substation for more than ten years.

It is now anticipated that the third transformer at Rangeway will be sufficient for the medium term. Recognising the potential for new large industrial block loads to connect in the area with relatively short lead times, our network development plan for the area allows for significant flexibility.

Depending on the size of load, some spare capacity will be available at both Rangeway substation and Geraldton terminal. A future new substation can also be established on the Durlacher site, following decommissioning of the existing substation by summer 2021/22.

Where possible, we have extended three phase power lines and installed automated, remotely controlled switches to allow interconnections. However, large portions of customers are fed from single phase rural distribution lines, which were specifically designed to supply farming loads. Material new block loads, such as grain handling facilities and processing plants, will require significant reinforcement works, such as the extension of three phase power lines.

The 33 kV network is constrained typically by voltage capacity rather than the thermal capacity of existing power lines. This is due to the relatively large distances required to transfer power from zone substations to supply customers. Generally, the 33 kV network in Country North has adequate capacity to supply the forecast natural load growth.

Opportunities for non-network solutions have been considered as alternative options, but show limited potential for application at this stage. The viability of non-network solutions is largely dependent on the rate of underlying growth of the feeder peak demand, types of loads (such as industrial and commercial) and risk to network security. For a non-network alternative to be the preferred solution, it must also deliver the required outcome at a lower cost to the network alternative.

The only committed projects that relate to capacity demand in this planning cluster are decommissioning of the aged Durlacher substation due to degraded asset conditions, and installation of a third 132/11 kV transformer at Rangeway substation.

[41] This major highway will reduce driving time from Perth to Geraldton by 40 minutes and is expected to be a significant driver for the growth of the central coast area.

Table 41: Country North 33 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions	WDC region[43]
Eneabba	Shire of Carnamah	Mid West	Central Midlands
Geraldton	Shire of Chapman Valley	Wheatbelt	Central Coast
Kalbarri	Shire of Chittering		Avon
Moora	Shire of Coorow		
Regans	Shire of Dalwallinu		
Three Springs	Shire of Dandaragan		
	Shire of Dowerin		
	Shire of Gingin		
	Shire of Goomalling		
	Shire of Greenough		
	Shire of Irwin		
	Shire of Koorda		
	Shire of Mingenew		
	Shire of Moora		
	Shire of Morawa		
	Shire of Mullewa		
	Shire of Northampton		
	Shire of Perenjori		
	Shire of Three Springs		
	Shire of Victoria Plains		

[42] Wheatbelt Development Commission region (where applicable).

Table 42: Country North 33 kV - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Installation of a third 132/11 kV transformer at Rangeway substation	Accommodate increasing demand in the area; create additional feeder capacity to allow for load growth and additional distribution transfer capacity.	Rangeway/ Geraldton	Summer 2017/18
Decommissioning of Durlacher substation	Address degraded asset condition.	Geraldton	Summer 2021/22

Country North 11 kV planning cluster

There is a moderate load density in the Geraldton - Greenough area due to residential and commercial loads in the city of Geraldton. The distribution networks supplying the City of Geraldton consist of three phase 11 kV feeders. The primary constraint on the 11 kV network is thermal capacity.

The 11 kV network in Geraldton - Greenough has seen moderate growth with several residential and commercial applications over the last couple of years.

There is limited distribution transfer capability between the 11 kV zone substations due mainly to thermal capacity constraints and limited physical interconnection points between feeders. Transfer capability is mainly reserved for fault conditions to restore power and minimise feeder outage times.

There are currently no committed capacity expansion projects in this planning cluster.

Table 43: Country North 11 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Chapman	City of Geraldton	Mid West
Durlacher	Shire of Greenough	
Rangeway		

7.2.2 Country South region

In general, the networks supplying the Country South region are radial, rural overhead power lines. There are two study areas within the Country South region:

- South-West study area, supplying large urban centres of the coastal region from Pinjarra in the north to Augusta in the south, as well as moderate density loads driven by horticulture, viticulture and tourism, with some larger industry and mining loads.
- Great Southern study area, which generally supplies broad acre, low density networks and is geographically located to the east of the South-West study area.

In this region all 19 substations have 22 kV feeder exits. However voltage in the eastern section of the Great Southern study area is stepped up to 33 kV to increase the voltage capacity of the feeders supplying loads over such long distances.

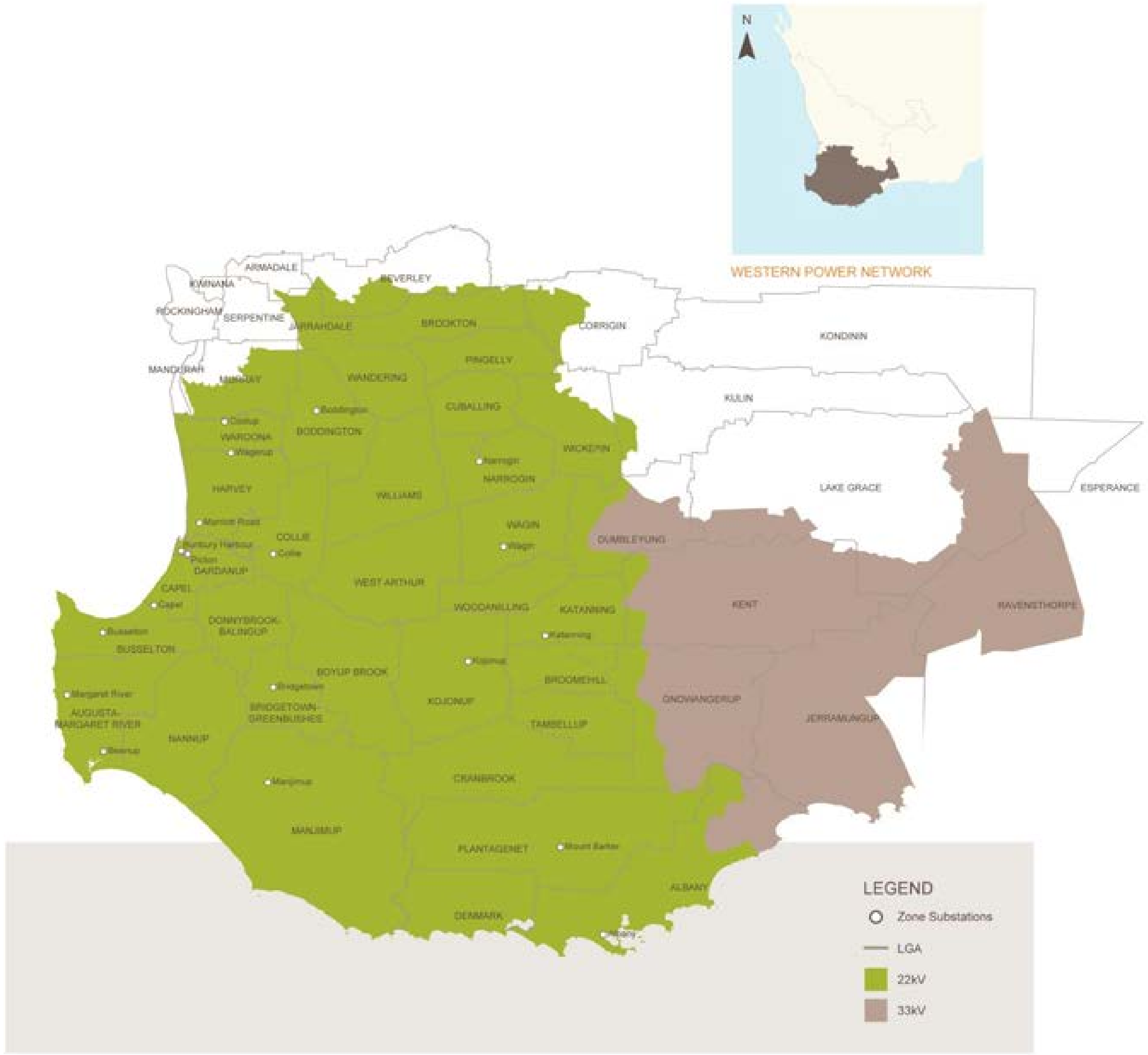
Table 44: Country South 22 kV South-West study area - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Beenup	Shire of Augusta-Margaret River	South West
Bunbury Harbour	Shire of Boyup Brook	
Busselton	Shire of Bridgetown-Greenbushes	
Bridgetown	City of Bunbury	
Capel	Shire of Busselton	
Collie	Shire of Capel	
Coolup	Shire of Collie	
Margaret River	Shire of Dardanup	
Marriott Road	Shire of Donnybrook-Balingup	
Manjimup	Shire of Harvey	
Picton	Shire of Manjimup	
Wagerup	Shire of Nannup	
	Shire of Murray	
	Shire of Waroona	

Table 45: Country South 22 kV Great Southern study area - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Albany	City of Albany	Great Southern
Boddington	Shire of Beverly	
Katanning	Shire of Brookton	
Kojonup	Shire of Broomehill	
Mt Barker	Shire of Boddington	
Narrogin	Shire of Cranbrook	
Wagin	Shire of Cuballing	
	Shire of Denmark	
	Shire of Dumbleyung	
	Shire of Gnowangerup	
	Shire of Katanning	
	Shire of Kent	
	Shire of Kojonup	
	Shire of Jerramungup	
	Shire of Manjimup (Walpole)	
	Shire of Narrogin	
	Town of Narrogin	
	Shire of Pingelly	
	Shire of Plantagenet	
	Shire of Ravensthorpe	
	Shire of Tambellup	
	Shire of Wagin	
	Shire of Wandering	
	Shire of West Arthur	
	Shire of Wickepin	
	Shire of Williams	
	Shire of Woodanilling	

Figure 35: Country South planning region



South-West study area

The South-West Study Area has moderate load density for rural feeders and strong but heavily loaded ageing rural feeders. The majority of the networks are overhead and supply moderately sized towns, some industry, horticulture, viticulture and tourism activities and some small mining activities. The loads generally peak in summer, driven by water pumping, air conditioning or cool storage.

As discussed in Section 6.8.2, capacity shortfalls arise at some substations in the next five years, including Capel, Bunbury Harbour and Busselton substations.

To help relieve limitations at Busselton substation, a new 132kV transformer is proposed by winter 2017, which reduces peak loading on degraded 66/22 kV transformers.

A new reconfigurable 33 MVA transformer at Capel will be installed by 2020/21 to address the capacity shortfall and support the Picton to Busselton line upgrade works. We will continue to operate the old transformers at Capel substation at as hot standby units.

There are plans to replace a degraded transformer at Picton substation by 2019/20. To align with the long term development strategy of the area, we will upgrade the transformer at Picton to a 132/22 kV transformer.

A new fourth transformer at Bunbury Harbour substation will address capacity limitations in the area.

In addition to declining substation load at Coolup, the long radial 66kV line and substation assets are degraded. We plan to transfer the entire load to the neighbouring Pinjarra substation which will facilitate decommissioning of the substation and its supplies.

Numerous assets at Collie and Coolup substations as well as their connecting transmission line circuits and plant equipment have been identified to be in degraded condition. We have plans to transfer the entire Coolup load to the neighbouring Pinjarra substation by 2018/19 and decommission the Coolup substation by 2020/21. We are still investigating resupply options for Collie substation.

Given the lead times associated with some projects, opportunities to transfer load between substations are being considered to manage the reliability of supply until alternatives are available, including non-network solutions. There is minimal transfer capability between the following pairs of substations due to distance, high network peak loading levels and strength of the distribution networks in this study area:

» Wagerup and Marriott Road substations
» Capel and Picton substations
» Capel and Busselton substations
» Busselton and Margaret River substations.

Within this study area, there are interconnections between the substations that supply Bunbury and its surrounds. However, there are thermal capacity constraints on the distribution network which limit the ability of the interconnections to transfer significant portions of load between Bunbury Harbor, Picton and Marriott Road substations.

Voltage regulation also affects capacity in this area due to the long distances from the dispersed substations.

Urban developments in and around the greater Bunbury area and Busselton are driving strong demand growth and network reinforcement in these areas. Moderate demand growth continues along the coastal edge with some major future augmentation anticipated. There is low demand growth for the rest of the study area and reinforcement is generally driven by customer bulk loads.

In the medium term, capacity augmentation will be needed to meet high growth around Bunbury and Busselton. Forecast growth in the Bunbury region and in particular, Eaton and Dalyellup, is likely to require new feeders in the next few years. With recent load growth in Busselton, the distribution capacity is at or near limits so a new Busselton East feeder is being considered to help resolve this issue.

Over the next five years, a number of heavily loaded single phase spurs will require reinforcement to ensure power quality and capacity.

Great Southern study area

The distribution network in this study area is generally long, lightly loaded overhead lines for generally small, dispersed and broad acre agricultural purposes. The exceptions are the networks supplying the larger towns of Albany, Katanning, Narrogin and Kojonup, as well as the coastal strip from Albany to Walpole.

We have recently replaced the three existing transformers at Narrogin substation with a single higher capacity unit which has created additional capacity in the area.

A number of transformers at Wagin substation are due to be replaced by 2019/20. Whilst there are no capacity constraints at these sites, reconfigurable units will be used to meet long term development needs in the area.

There is negligible overall load growth in this study area, instead load requirements have shifted from lower load grown areas to other growth areas. Small growth has centred around City of Albany and along the south coast between Albany and Walpole. Steady, but low, load growth is expected, leading to incremental reinforcement to the network. With minimal load growth elsewhere, any associated augmentation to the distribution network will be driven by material block loads.

The long radial distribution networks cater for typical broad acre rural load types. Changing characteristics of loads such as an increase in local mining in Boddington and more load intensive viticulture and tourism-based industries in Denmark and Walpole have affected the distribution networks.

Over the next ten years reinforcement of the distribution network between Denmark and Walpole will be required to meet forecast demand. This will ultimately include an additional distribution feeder, however this may be deferred due to reactive power support, along with demand management and the more traditional application of voltage regulators.

There are opportunities for non-network solutions for Denmark and Walpole. These include demand management and energy efficiency programs as well as the introduction of fast-acting reactive power devices (such as STATCOMs). These non-network solutions need to mitigate capacity constraints on the distribution network in the short and medium terms.

Table 46: Country South 22 kV - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Capel: 509 Feeder upgrade thermally under rated conductor	Improve thermal capacity of the supply to Donnybrook via upgrade of under rated conductor.	Donnybrook	Winter 2017
Busselton: Partial conversion of Busselton 66 kV substation to 132 kV	Address degraded asset condition; accommodate increasing demand in the area.	Busselton	Winter 2017
Busselton: Feeder reconfiguration of new 22 kV switchboard	Reconfiguration of feeders at the Busselton substation as part of the installation of a new 22 kV switchboard in BSN substation.	Busselton	Summer 2017/18

Country South 33 kV planning cluster

This voltage cluster supplies the eastern section of the region. Due to the extremely long and lightly loaded distribution networks, the supply voltage has been increased from 22 kV to 33 kV at some point along the feeders at four distribution substations. These are Dumbleyung substation (from Wagin Zone substation), Badgebup substation (from Katanning Zone substation), Gnowangerup substation (from Katanning Zone substation) and Green Range substation (from Albany Zone substation).

There has been an increase in local mining in Ravensthorpe, and tourism and abalone farming in Bremer Bay, which have changed the load characteristics in the area. The long radial distribution networks in this voltage cluster were not designed to cater for load types above typical broad acre farming.

We have worked with the community in Ravensthorpe to establish a medium term Network Control Service to aid supply to the community. This work allows significant expenditure to be deferred on very long radial feeders that peak only for short periods throughout the year, such as the Gnowangerup feeder that supplies Ravensthorpe.

Edge-of-grid power stations present opportunities to increase capacity, as well as address reliability problems experienced by communities located at the end of long radial feeders. Diesel power stations have already been deployed at Ravensthorpe and Bremer Bay.

There are no committed capacity expansion projects in this planning cluster.

7.2.3 Country East region

The Country East region covers the Wheatbelt to the east of Perth. The region is defined by Sawyers Valley in the west, Coolgardie in the east, Mount Marshal in the north and Lake Grace in the south. The demand is a mixture of general agriculture and water pumping. There are also residential, commercial and light industrial loads in towns such as Northam, Kellerberrin, Cunderdin, Merredin and Kondinin. Mining loads also exist in and around Southern Cross.

As load density in the Country East region is relatively low, the power lines have been designed for a lower current-carrying capacity. The primary constraint in the region is voltage regulation, due to the long radial nature of the local distribution networks. Block load applications tend to dominate growth in the area, rather than underlying load growth rates.

Ten substations supply the Country East region at either 22 kV or 33 kV.

Country East 22 kV planning cluster

Transformers at Cunderdin, Kellerberrin and Northam substations are in degraded condition, and treatment assessments have identified opportunities to partially refurbish the transformers and defer replacement beyond five years.

The distribution networks in this region tend to follow agricultural boundaries, and power lines tend to sit west of Merredin due to the prominence of the agricultural load. Recently, there has been no need to build significant new infrastructure as there has been minimal agricultural development in this cluster over the past five years.

Load transfer in this cluster is restricted by voltage regulation and limited interconnections between the long radial distribution power lines. This is typical of most rural feeders. Where practical, we have extended three phase power lines and installed automated remote control switches to allow interconnection. For safety reasons, we do not generally interconnect single phase lines.

A large portion of customers are supplied from single phase rural distribution lines. These spurs were specifically designed for farming type electricity demands. Significant block loads such as grain handling facilities and processing plants often require major reinforcement and extension of three phase power lines. The distribution networks within this cluster are robust.

There are presently no major thermal constraints within this cluster.

However, there are a few minor issues on some of the single phase spurs connected to the feeder backbone. As the loads on individual single phase spurs grow, the phase imbalance is approaching a point where augmentation will be required to rebalance the loads on each phase and reduce neutral currents.

The strategy for reducing phase imbalance will be one of the following options:

- Converting existing single phase spurs into two phases or three phases
- Installing isolation transformers at the beginning of the heavily loaded single phase spurs.

Some supply areas have the potential to develop voltage constraints over the next few years. Load forecasts suggest that the demand in these areas may exceed the distribution voltage capacity. The proposed solution is to install voltage regulators on those feeder backbones.

In addition to the voltage constraints, it is anticipated that load growth in areas such as York, Toodyay and Nungarin will cause feeders in this cluster to approach thermal capacity limits over the next few years. We are monitoring the cluster and further studies are being performed to determine prudent options to meet forecast load growth.

Table 47: Country East 22 kV - zone substation, LGA and region

Zone substations	DRD regions	Local government authorities	WDC[44] region
Carrabin	Wheatbelt	Shire of Beverley	Avon
Cunderdin		Shire of Bruce Rock	Central East
Kellerberrin		Shire of Cunderdin	(Perth)
Merredin		Shire of Dowerin	Central Midlands
Northam		Shire of Goomalling	
Wundowie		Shire of Kellerberrin	
		Shire of Koorda	
		Shire of Merredin	
		Shire of Mt Marshall	
		Shire of Mukinbudin	
		Shire of Mundaring	
		Shire of Northam	
		Town of Northam	
		Shire of Nungarin	
		Shire of Quairading	
		Shire of Tammin	
		Shire of Toodyay	
		Shire of Trayning	
		Shire of Victoria Plains	
		Shire of Westonia	
		Shire of Wyalkatchem	
		Shire of York	
		Shire of Yilgarn	

[43] Wheatbelt Development Commission region (where applicable).

Table 48: Country East 22 kV planning cluster - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Northam: York Feeder Beverly Leg - install third voltage regulator	Mitigate the low voltage issues on the York feeder Beverly Leg. Reduce feeder utilisation and enable reliability of supply to new and existing loads	York/Beverley	Winter 2017
EC: Upgrade single phase Batch 3	Creation of capacity on single phase line and catering for compliance issues	Wundowie	Winter 2017
Northam: York Feeder York Leg - install second voltage regulator	Mitigate the low voltage issues on the York feeder York Leg. Reduce feeder utilisation and enable reliability of supply to new and existing loads	York	Summer 2018/19
Northam: Upgrade single phase batch 4	Creation of capacity on single phase line and catering for compliance issues	Northam	Winter 2017

Figure 36: Country East planning region

Country East 33 kV planning cluster

Recent infrastructure reinforcements within this cluster have been minimal. Demand has remained steady, however, mining and water pumping station loads become prominent east of Merredin. As discussed in Section 6, no substation capacity constraints are forecast over the next five years.

As in the Country East 22 kV area, load transfer in this cluster is restricted by voltage regulation and limited interconnections. Many customers in this cluster are also supplied off the single phase rural distribution lines, which were originally designed for farming electrical demand.

The existing Southern Cross voltage regulator has limited capability, resulting in voltage issues around the substation under certain load conditions. As an interim measure, this is managed operationally through alternate network configurations. We plan to replace the voltage regulator with increased capability to address these voltage issues by 2017/18.

Table 49: Country East 33 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD region
Bounty	Shire of Bruce Rock	Wheatbelt
Kondinin	Shire of Corrigin	
Southern Cross	Shire of Coolgardie	
Yilgarn	Shire of Dundas	
	Shire of Dumbleyung	
	Shire of Kondinin	
	Shire of Kulin	
	Shire of Lake Grace	
	Shire of Mukinbudin	
	Shire of Narembeen	
	Shire of Nungarin	
	Shire of Westonia	
	Shire of Wickepin	
	Shire of Yilgarn	

Table 50: Country East 33 kV planning cluster - committed projects and expected benefits

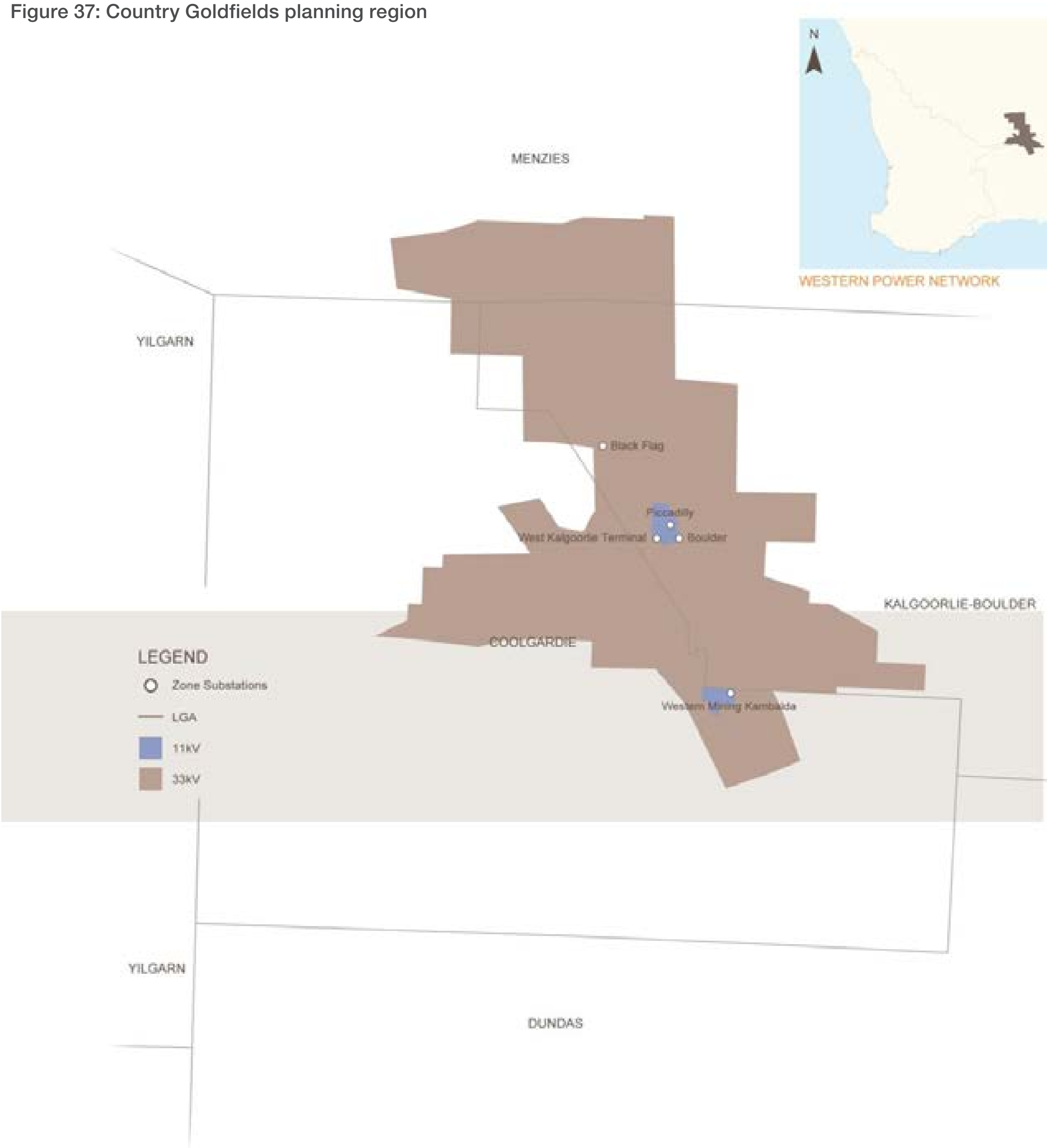
Project	Benefit/s	Area/s	By when
Replacement of Southern Cross substation regulator	Address degraded condition and mitigate high voltage issues under certain load conditions	Southern Cross	Summer 2017/18

7.2.4 Country Goldfields region

The Country Goldfields region is predominantly mining loads near Ora Banda, Black Flag, Kanowna, Boulder, Coolgardie and towards Kambalda. The region also includes the City of Kalgoorlie-Boulder, whose loads are mainly residential with pockets of commercial and light industrial.

There are currently five substations feeding the Country Goldfields region. Two distribution voltage levels, 11 kV (for the City of Kalgoorlie-Boulder and Kambalda) and 33 kV (mainly for mining customers) are used to reticulate electricity throughout the region.

Figure 37: Country Goldfields planning region



Country Goldfields 11 kV planning cluster

Load growth in Kalgoorlie-Boulder fluctuates, as the local economy is largely dependent on the mining industry. The commodities sector boom has contributed to significant growth in the last decade. The distribution networks in the City of Kalgoorlie-Boulder are relatively robust, with very few capacity constraints at this point in time.

As discussed in Section 6, no substation capacity constraints are forecast to emerge in this cluster over the next five years.

Load transfer between the 11 kV networks of Western Kalgoorlie terminal and Piccadilly substation is viable, with the existing interconnections and feeder exit cable ratings. Due to their separation, Western Mining Kambalda's 11 kV feeders are islanded from the other 11 kV distribution networks within the region.

There are currently no major thermal or voltage capacity constraint issues on the distribution networks within this cluster. Reinforcement of the 11 kV distribution networks is sporadic and normally driven by specific mining and industrial block loads.

Based on the load growth forecast over the next five years, a small number of thermal constraints may arise on the 11 kV distribution network within the City of Kalgoorlie-Boulder. Load transfers to adjacent lightly loaded feeders will be the most efficient way to resolve these issues.

There are currently no committed capacity expansion projects in this planning cluster.

Table 51: Country Goldfields 11 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Piccadilly	City of Kalgoorlie-Boulder	Goldfields-Esperance
West Kalgoorlie terminal 11 kV	Shire of Coolgardie	
Western Mining Kambalda		

Country Goldfields 33 kV planning cluster

The feeders in this cluster are predominantly mining feeders. There are very few constraints imposed on natural load growth, however, new mining loads are generally significant and require major reinforcement. These are determined on a case-by-case basis. Additional mining loads are required to queue for connection to the network. Significant capital contributions are often required upfront to underwrite large investments in the distribution network.

As discussed in Section 6, no substation capacity constraints are forecast to emerge in this cluster in the next five years.

Interconnection exists between Western Kalgoorlie terminal and Boulder substation, but this is limited by the thermal rating of the 33 kV distribution power lines.

Considering the natural load growth within this cluster, there are no requirements for distribution network reinforcements. However, any proposed significant block load north of Kalgoorlie will likely trigger the need to install a third transformer at Black Flag substation. All other reinforcement for new mining loads will be determined on a case-by-case basis.

There are currently no committed capacity expansion projects in this planning cluster.

Table 52: Country Goldfields 33 kV - zone substation, LGA and region

Zone substations	Local government authorities	DRD regions
Black Flag	Shire of Coolgardie	Goldfields-Esperance
Boulder	City of Kalgoorlie-Boulder	
West Kalgoorlie terminal 33 kV	Shire of Menzies	

7.3 Under fault rated conductor

Sections of the high voltage distribution network have been identified as being under fault rated, which means they have insufficient rating to safely carry currents likely to flow in worst-case fault conditions. These situations arise when augmentations (such as the construction of a new zone substation) increase the fault levels in the distribution network beyond the withstand capability of existing assets. This leads to the asset being under fault rated. Fault current passing through an under fault rated section of the network may cause the conductor to sag (breaching safe clearance requirements) or break. Conductor failures, in turn, have the potential to cause power outages, bushfires or injury to the public and our people.

This constraint occurs primarily in the country distribution network where conductors are designed to carry lower load currents which also have lower fault rating withstand ability.

We are currently implementing the under fault rated conductor strategy to reduce under-fault-rated conductors on our network. However, fault levels are still increasing due to network topology changes and customer connections/disconnections so the overall amount of under-fault-rated conductor continues to grow.

There is a plan to either remove or suitably protect these sections of conductor over the next ten years. The high priority sections are being investigated and a detailed options analysis is being carried out to identify the most prudent investment option to address these conductors by the end of the third Access Arrangement (2016/17). It is envisaged that the remainder of the medium to lower risk conductors will be addressed by the end of the fourth Access Arrangement (2021/22).

Table 53: Under fault rated conductor - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Albany: Mitigate under fault rated conductor	Mitigate safety risk and risk of outages due to under fault rated conductor; ensure compliance with the Technical Rules in relation to fault level requirements via either replacement and/or improvement in protection.	Albany	Winter 2017
Bridgetown: Mitigate under fault rated conductor		Bridgetown	Summer 2017/18
Bunbury: Mitigate under fault rated conductor, Stage 1		Bunbury	Winter 2017
Bunbury: Mitigate under fault rated conductor, Stage 2		Bunbury	Summer 2017/18
Bunbury: Mitigate under fault rated conductor, Stage 3		Bunbury	Winter 2017
Busselton: Mitigate under fault rated conductor		Busselton, Dunsborough, Yallingup, Broadwater	Winter 2017
Byford: Mitigate under fault rated conductor		Byford	Winter 2017
Chapman: Mitigate under fault rated conductor		Chapman	Winter 2017
Collie: Mitigate under fault rated conductor		Collie	Winter 2017
Cunderdin: Mitigate under fault rated conductor		Cunderdin	Winter 2017
Eneabba: Mitigate under fault rated conductor		Eneabba	Summer 2017/18
Geraldton 33kV: Mitigate under fault rated conductor Stage 2		Geraldton	Winter 2017
Kalamunda: Mitigate under fault rated conductor		Kalamunda	Winter 2017
Katanning: Mitigate under fault rated conductor		Katanning	Winter 2017

Table 53: Under fault rated conductor - committed projects and expected benefits (continued)

Project	Benefit/s	Area/s	By when
Kellerberrin: Mitigate under fault rated conductor	Mitigate safety risk and risk of outages due to under fault rated conductor; ensure compliance with the Technical Rules in relation to protection and fault level requirements via either replacement and/or improvement in protection.	Kellerberrin	Winter 2017
Kojonup: Mitigate under fault rated conductor		Kojonup	Winter 2017
Manjimup: Mitigate under fault rated conductor		Manjimup	Winter 2017
Margaret River: Mitigate under fault rated conductor		Margaret River	Summer 2017/18
Medina: Mitigate under fault rated conductor		Medina	Winter 2017
Merredin: Mitigate under fault rated conductor		Merredin	Winter 2017
Midland Junction: Mitigate under fault rated conductor		Midland Junction	Winter 2017
Moora: Mitigate under fault rated conductor		Moora	Winter 2018
Morley: Mitigate under fault rated conductor		Morley	Winter 2017
Northam: Mitigate under fault rated conductor		Northam	Summer 2017/18
Piccadilly: Mitigate under fault rated conductor		Piccadilly	Summer 2017/18
Southern Cross: Mitigate under fault rated conductor		Southern Cross	Winter 2017
Wagerup: Mitigate under fault rated conductor		Wagerup	Winter 2017
West Kalgoorlie terminal: Mitigate under fault rated conductor		West Kalgoorlie	Winter 2019
Kondinin: Mitigate under fault rated conductor & protection reach		Kondinin	Winter 2017
Three Springs: Mitigate under fault rated conductor & protection reach		Three Springs	Winter 2017

7.4 Constrained distribution transformers

Our network includes a fleet of 65,828 distribution transformers.

For large units (capacity of 100 kVA or greater), the risk of distribution transformer overload increases significantly in heatwave conditions[44] in which load increases of 200 to 300 per cent are common. At the time of a transformer's installation, there is usually no information available on the number of customers it will service or the load to which it will be subjected.

Transformers with lower capacity usually service single customers, are normally sized for the maximum load of that customer and are less likely to become overloaded.

Historical data indicates that approximately 5 per cent of the larger capacity transformers are at risk of overloading and will fail if not replaced before the next heatwave. Such failures may initiate a fire and therefore present a public safety risk. This failure rate increases significantly for overloaded transformers during a second heatwave.

The risk of transformer failures has been reduced significantly by the Overloaded Transformer Program. Since its introduction in 2005, fewer than five (on average) transformers have failed each year as result of overloading, compared to 52 transformer failures in a single high load day in 2004.

Each year, a load analysis is conducted on all distribution transformers in the network, assessing parameters such as:

» customer consumption data
» number and type of customers
» summer peak feeder loads
» transformer capacity.

The analysis prioritises the replacement of overloaded transformers, based on risk. A distribution transformer is considered to be at risk of overloading when its:

» calculated peak load exceeds the nameplate continuous rating by 35 per cent[45]
» top-oil temperature exceeds 115°C
» winding hot-spot temperature exceeds 140°C.

The Overloaded Transformer Program has helped us identify and manage the transformers at highest risk of being overloaded and this year's replacement project is underway. After summer 2016/17, analysis will begin to identify the transformers at risk for 2017/18.

Distribution transformers with capacities below 100 kVA are managed through the asset replacement program using a 'replace on failure' strategy. Their condition is, however, routinely monitored during the four year pole inspection cycle and assets with physical evidence of deterioration (such as significant oil leaks) are addressed before they fail in service.

[44] In this discussion, a heatwave is defined as a period of three or more consecutive days in which daytime temperatures exceed 40°C and remain at 26°C or higher at night.
[45] Transformers can be operated safely beyond their nameplate continuous rating for short periods without adversely affecting asset life. The combination of the peak load and utilisation factor criteria account for this.

Table 54: Overloaded transformer program - committed projects and expected benefits

Project	Benefit/s	Area/s	By when
Metro Transformer Overload Upgrade	Identify and replace distribution assets performing beyond their design capacity to reduce the risk of asset failure.	Metro	Yearly program
North Country Transformer Overload Upgrade		North Country	Yearly program
South Country Transformer Overload Upgrade		South Country	Yearly program

7.5 Non-competing threshold for generators

Inverter connected generators with a total installed capacity less than 1 MVA connecting to the distribution network will be deemed as not constrained and non-competing for capacity on the transmission network, as the assessed transmission network impact is low. This excludes network protection assessments, which may impact the ability to connect. Parts of our network which are deemed "at risk"[46] are provided and the capacity to connect at these sites may require further assessment.

With the dynamic nature of the network and the increasing penetration levels of distribution embedded generation with an installed capacity less than 1 MVA, we will review this threshold on a routine[47] basis and communicate any change directly to key industry bodies. For further details, please contact the Access Solutions Manager at customer.connection.services@westernpower.com.au.

[46] At risk substations are limited in accommodating a significant capacity (≤2.5 MW) of inverter connected distribution embedded generators. These zone substations include Coolup (CLP), Kellerberrin (KEL), Kojonup (KOJ), Mundaring Weir (MW), Southern Cross (SX), Beenup (BNP), Mount Barker (MBR) and Wagin (WAG).

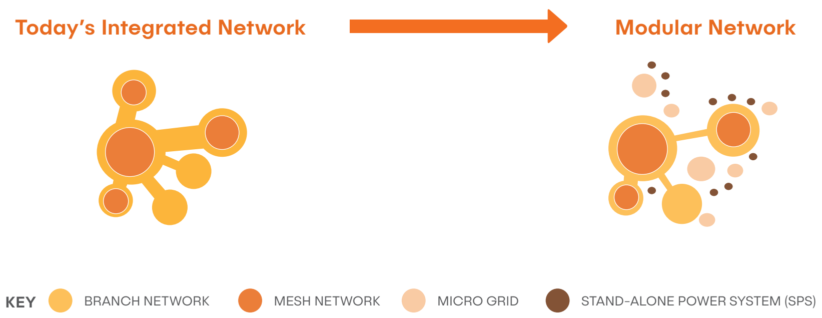
[47] Routine impact assessments will be conducted on a quarterly basis for the first year of implementation and performed on annual basis thereafter.

8. NETWORK IMPACTS OF EMERGING TECHNOLOGY

The operating model of the traditional network services business is evolving as new technologies present a range of options for consumers. They can generate and store electricity at their premises and, as energy storage becomes an increasingly cost-effective option, storage can be used for managing peak demand growth and other network issues.

International experience suggests modern power networks are moving away from an integrated, meshed network model characterised by predominantly one-way power-flows, centralised large-scale generation and long radial transmission links. They are moving to a more modular system, see figure 38, incorporating strongly meshed urban distribution networks with bi-directional energy flows, lower capacity connections to areas with local generation and storage, dynamically connected microgrids and stand-alone power systems.

Figure 38: The evolution of the network



Whether or if the network follows this evolutionary model will depend on the extent to which customers adopt new and competing technologies, along with the actions of competitors deploying disruptive technologies, and our adoption of innovative technologies or alternative operating models to respond to changing customer demands.

The work across innovation and emerging technology is providing insight into the risks, opportunities, barriers and relative competitive advantages that will influence our decision-making and long term planning.

Individual projects have been designed to develop an understanding of the most immediate and significant of the changes occurring in the electricity supply market, in order to define the range of potential responses at our disposal.

8.1 Understanding emerging technology trends

We are learning about the physical, statutory and commercial implications of disruptive technologies in an Australian context; taking into account local factors such as policy and regulatory frameworks, consumer trends and Australian utility experience.

Ultimately, the business has identified technologies that are most likely to emerge as disruptive factors on the SWIS over the next five to ten years. A suite of pilot projects and collaborative studies are underway, these will develop our understanding of emerging technologies likely to have the most immediate and material impact on the business.

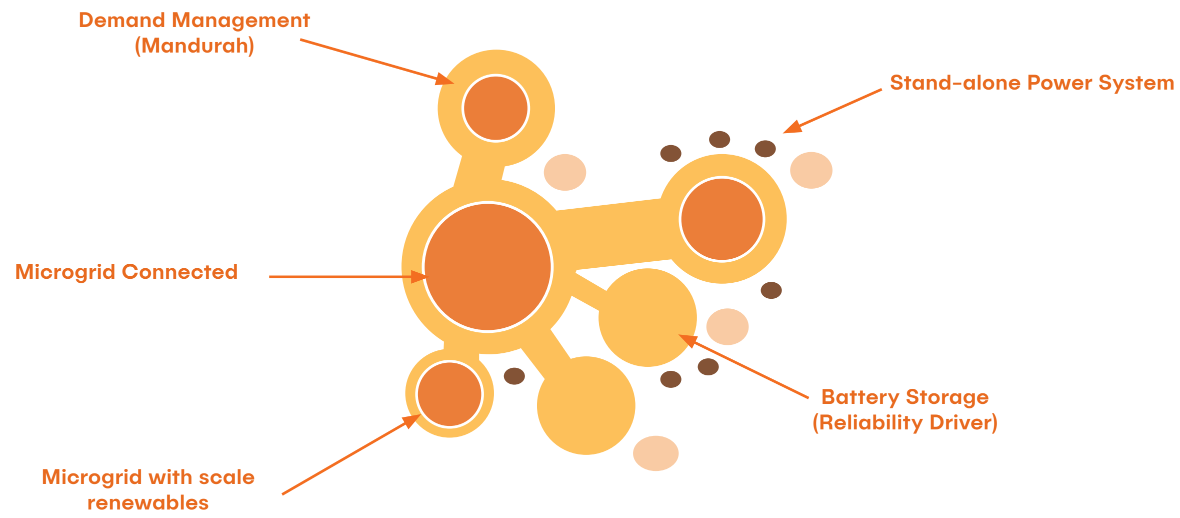
8.2 Understanding network evolution

International experience suggests a modular network is likely to present an improved opportunity for customers to maximise the value of their Distributed Energy Resource (DER) investment, and increase the renewable energy uptake while maintaining network relevance.

In order to understand the opportunities presented to us through the adoption of a modular network model, a re-think of the traditional supply model is required. Developing a modular network model will entail investment in maintaining the relevance of the 'connected network' and deploying supply infrastructure that improves the customer experience and maximises the value of DER technology investments.

Figure 39 below provides a graphical representation of how the discrete projects are aligned with the potential network development path.

Figure 39: Focus of emerging technology projects



8.3 Responding to technology challenges

Short-term, our approach to new technologies is to modify our existing network operating model so emerging technologies can leverage the value of the network to benefit both customers and our business. This will encourage greater penetration of DER and will optimise the use of our existing network now and into the future. We have begun projects to build our understanding of the cost, performance and consumer impacts of emerging technologies most likely to impact the business in the short term.

Current projects

- **Stand-alone Power Systems (SPS)** – SPS may offer an economically efficient alternative to network rebuild. We have selected a partner for the design, construction and installation of six SPS units in rural areas around the Ravensthorpe district. The units have been commissioned and will be monitored for 12 to 24 months (starting July 2016). (see section 8.4.1 . for additional detail).
- **Battery Energy Storage System (BESS)** – Price reductions present the potential for storage to resolve reliability issues that have been out-of-reach because of the cost of network solutions. We have procured a 1MWh battery storage system to be installed at Perenjori as a non-traditional approach to rural power reliability. The battery will be commissioned in 2017 (see section 8.4.2 for additional detail).
- **Microgrid Development (White Gum Valley and Garden Island Microgrid)** – The modular network of the future is likely to include microgrids. The two ARENA-funded microgrid projects with Curtin University Sustainability Policy (CUSP) Institute and Carnegie Wave Energy are building our understanding of the commercial and consumer drivers for microgrids and are forming a view on our potential role in supporting microgrids. The Carnegie microgrid development and the CUSP microgrid development are currently in detailed planning and construction (see section 8.4.3 for additional detail).
- **Mandurah/Meadow Springs major network investment deferral** – Electricity network businesses around the world are exploring (and finding) non-traditional network solutions to be a lower-cost alternative to meet increasing consumer demand. Investigations into non-traditional network planning opportunities for the Mandurah/Meadow Springs area have begun with responses from the market received in August 2016 (see section 8.4.4 for additional detail).
- **Kalbarri Microgrid** – we have had high-level discussions with the Mid West Development Commission (MWDC) about the potential for a collaborative project to improve power reliability and sustainability at Kalbarri through the development of a dynamically connected microgrid. A feasibility study on potential for the solutions was delivered in September 2016 (see section 8.4.5 for additional detail).
- **Embedded Networks** – we have started work internally and in partnership with specific developers to understand if an alternative network model incorporating distribution level storage is a more cost effective way to deliver electricity. The initial stage of the project was completed in 2016 (see section 8.4.6 for additional detail).
- **Alternative Network Architectures** – There are currently sizeable sections of our rural distribution network nearing design life and requiring replacement in the near future. These sections of the network developed and expanded through organic growth over the past 40-50 years. As a result, we have an opportunity to optimise the network by considering alternative approaches to supplying power to affected customers. In 2014-15 an algorithm for optimising network topology was created and applied to a rural feeder. The results were promising and we will continue work to improve the model. This project aims to optimise the distribution network by expanding the previous network optimisation algorithm to identify stand-alone power systems (SPS). The results so far suggest that strategically placed SPSs are a cost effective alternative to replacing certain sections of our rural distribution network.
- **Fusesaver** – we have recently begun trialling this new technology, installing a number of Fusesavers in strategic locations. Fusesavers have the potential to reduce operating expenditure of supply restoration during a temporary fault event. The Fusesavers' ability to reclose after a short open period, typically 10 seconds, is expected to significantly reduce outage durations for customers located at the periphery of rural distribution networks. The trial is expected to deliver results by the end of 2017 (see section 8.4.9 for additional detail).
- **Building alliances and knowledge networks** – By reaching out to innovators and thought leaders, we will make the most of collaborative opportunities to build industry knowledge and learn from others' experiences (see section 8.4.8 for additional detail).

These projects and trials will be implemented and assessed over the next 6-18 months. The outcomes, as well as the outcomes of the market change programs underway, will inform the business' tactical response to emerging issues such as regulatory reform.

8.4 Projects in detail

8.4.1 Stand-alone Power Systems (SPS)

SPS may present an economically efficient alternative to network rebuild. We have executed a contract with a preferred-bidder for the design, construction and installation of six SPS units in rural areas around the Ravensthorpe district. The units were installed and commissioned in the first half of 2016. Target outcomes from the trial include avoidance of capital investment in non-economic areas, reduction in the rural/metropolitan cross-subsidy and reduction in pressure on tariffs, improved reliability for consumers and amelioration of fire safety risk related to network asset failure.

The project is looking to the market to provide an innovative response to constructing, operating and maintaining consumer supplies using a non-traditional approach that integrates renewable generation, energy storage, stand-by (back-up) supply and consumer engagement to improve the customer experience. Supporting work includes:

- Assisting with the development of a regulatory framework that clarifies where and how predominantly renewable stand-alone systems can be used to replace traditional network supply
- Developing a network planning toolkit that considers customer density, aggregated demand and cost-to-serve when deciding between network and non-network solutions
- Working with customers to understand what support/securities need to be in place to ensure that they are confident of support under a non-interconnected model.

The success of the SPS program will depend on us demonstrating that the SPS product is economically efficient and acceptable to the consumer-base. Ongoing consumer engagement will help shape the product offering to ensure it meets consumer needs.

We also need to establish the regulatory mandate to own and operate the SPS or otherwise develop a model for deployment that enables the business to incorporate SPS deployment into its suite of planning options whilst preserving the ability to earn a return on (or of) the investment.

Given the volume of potential SPS candidates identified in the forward works program, it is unlikely that SPS deployment will form a significant component of our ongoing business.

In the short term, the deployment and funding model for SPS deployment is focused on preserving the value of the investment.

8.4.2 Battery Energy Storage System (BESS)

Lower prices means battery storage may be a more cost effective solution to resolve reliability issues that were previously out-of-reach. We have procured a 1MWh battery storage system to be installed at Perenjori (east south east of Geraldton) as a non-traditional approach to addressing rural power reliability. The project is expected to be commissioned in 2017.

The project aims to:

- Understand the opportunities presented by distribution-scaled energy storage
- Develop non-traditional and cost-effective rural reliability options for network planning
- Provide an innovative and cost-effective option for energy storage at the distribution level
- Include energy storage options into our planning toolkit to respond to reliability challenges and gain insight into other potential energy storage applications.

The success of the BESS project will be measured by reliability of the supply to the Perenjori town-site versus the expected impacts of traditional network enhancement opportunities. The Perenjori BESS project will need to demonstrate a material improvement in reliability as well as learnings about scoping, procuring, deployment and operation of energy storage.

To be considered a success the project will also need to provide insights into the use of battery storage systems to achieve additional network and market outcomes.

Learnings (both commercial and operational) will also inform ongoing network planning and optimisation projects such as the Mandurah/Meadow Springs capacity planning project.

The potential for incorporating energy storage into business-as-usual network planning and demand management will increase as the price of energy storage options falls. Learnings from the BESS project will inform our ongoing regulatory engagement with respect to the use of energy storage devices in a network support capacity (voltage, frequency, demand management) or a tool for profitable market participation (shifting the generating profile of renewable generating plant).

8.4.3 Microgrid development (CUSP and Garden Island Microgrid)

The modular network of the future is likely to include microgrids (incorporating generation, energy storage and integrating technologies with weak grid connections or predominantly isolated operation). The ARENA-funded microgrid projects with Curtin University Sustainability Policy Institute and Carnegie Wave Energy are helping us form a view on our potential role in supporting microgrids.

One of our focuses throughout these projects is working with energy industry participants, researchers, developers, investors and consumers to understand how, where and when microgrids become a commercially viable alternative to network extension. Specifically, we are seeking an answer to the following questions:

- How will the Technical Rules need to evolve to keep pace with changing options and changing consumer expectations
- How might leveraging the existing network support the economic development of microgrids, minimising the capital required to create the supply models of the future
- How might our existing skillsets be deployed to support the ongoing management of microgrids for fault response
- What is the optimal microgrid/network integration model that motivates continued interaction between the wider network and the microgrid to provide benefits to both microgrid users and network users?

The Carnegie microgrid development and the CUSP microgrid development are underway.

Microgrids are a developing area of our business, urban planners and developers are looking for new and innovative approaches to property development and urban infill.

While we maintain the role of incumbent network owner and operator, the opportunity exists for the business to bring microgrid management into its suite of services in the same way it accepts accountability and ownership for traditional distribution network developments.

Through developing skills in the integration of competing generating sources supplying the same microgrid, we may have an opportunity to transition system development skills and capacity into an equivalent role on the distribution network.

We may also be able to encourage the development of microgrids in areas of the network experiencing peak demand constraints. This may generate symbiotic benefits across the networks that leverage the diversity of peaks and access to available distributed generation at peak times and avoid costly network investment.

8.4.4 Mandurah/Meadow Springs major network investment deferral

Electricity network businesses around the world are finding non-traditional network solutions require lower capital costs and can be more flexible in meeting changing demand requirements.

We have tools in place to help planners identify opportunities for non-traditional solutions, however so far, there haven't been any non-traditional solutions implemented. We need to re-examine tools and processes to ensure they meet the rapidly-expanding suite of alternatives to network extension and augmentation.

The current load growth in the Mandurah area is an excellent test case that will be developed by a project team focused on building organisational planning capability and, ultimately, providing a material network investment deferral.

The bulk of load in the Mandurah area is located along the southern metropolitan coastal strip served by the Mandurah (MH) and Meadow Springs (MSS) zone substations, both of which are experiencing rapid growth compared to most of the network.

The forecast peak demand growth rate for MH is 5.5 MVA/annum. Current projections show that continued growth in peak demand will exceed transformer capacity at MH zone substation. To mitigate a capacity shortfall and restore full network Technical Rules compliance Stage 2 of the Mandurah load area investment strategy (approximately $30M) will be required within five years.

Detailed investigation into alternative (non-traditional) solutions and implementation of prospective opportunities, with a plan to shift and/or reduce peak demand, could defer the requirement for significant investment (Stage 2) at MH zone substation. The scope of the proposed project would be:

- reviewing the current Demand Management (DM) screening tool documenting potential changes. Update variables (e.g. price of batteries) and where changes are quick to implement, make these changes to the tool. Collect longer term improvement ideas with the plan to implement either as part of the assessment of the Mandurah opportunity or at the completion of the project
- use the updated DM screening and planning assessment tools to prepare targeted investment options and a recommendations report to address forecast network constraints in the greater Mandurah area
- engage customers and electricity industry participants to understand how different options might meet their needs and how best to implement them
- develop a business case and plan for the implementation of non-traditional (and traditional where appropriate) network solutions in the Mandurah area
- update DM Screening and assessment tools based on the learnings from the Mandurah assessment.

The measure of success of the Mandurah Meadow Springs project will be the development of a suite of new technology enabled demand side management (DSM)/network planning options that can be deployed across other areas of the network where consumer demand is generating pressure for network investment.

A suite of effective DSM and alternative network development tools will allow our network planners to develop networks of the future that achieve optimised asset utilisation for least-cost capital investment.

This outcome limits pressures on regulated tariffs and allows us to operate our asset fleet at the most efficient and effective way.

8.4.5 Kalbarri Microgrid

The Kalbarri town-site is currently solely supplied via the 150km, 33kV radial Kalbarri feeder from the Geraldton substation. The Kalbarri feeder is exposed to wind-borne salt and dust pollution and as such is particularly prone to pole-top fires which can lead to extended outages on the line. The feeder also supplies a number of isolated customer sites via spurs off the main feeder. Kalbarri has a tourism-based economy and therefore tends to reach peak loading during the summer and Easter periods each year.

We have had high-level discussions with the Mid West Development Commission (MWDC) investigating the potential for a collaborative project to improve power quality, reliability and sustainability at the Kalbarri town-site through the development of an integrated and dynamically connected microgrid.

A high-level scope of the project will be presented to external funding programs to ascertain the likelihood of funding being provided for the project. A microgrid could include any or all of the following components:

» continued connection of the Kalbarri feeder
» a community-scaled solar farm
» the existing Synergy windfarm
» large-scale energy storage and integration
» peak management through distributed generation or demand response
» instituting an intensive preventative maintenance regime on the Kalbarri feeder between the windfarm site and the township
» other local generation
» control systems to modify the microgrid between connected and disconnected arrangements and to manage power quality and security in a disconnected operating mode.

8.4.6 Embedded networks

Independent third parties (property developers and electricity solutions businesses) are showing interest in alternative network options that provide a cost advantage and/or differentiator.

Developers want to minimise sub-division electrical costs within a proposed sub-division and often require augmentation works upstream of the potential embedded network connection point. We will consider alternate development models (e.g. using distributed energy resources) with the potential to impact the peak network demand of a residential development, potentially forestalling the need for network augmentation.

Under the right revenue model, increasing the use of distribution networks (increasing energy throughput without increasing peak demand) may have a positive impact on our revenues with no detrimental impacts on network tariffs.

We are looking to:

» test if there is a cost advantage within a sub-division/embedded network using battery storage and/or DER – e.g. different size/number of transformers, different cable specification
» investigate limitations we face performing our traditional role within a low cost embedded network.

8.4.7 Alternative Network Architectures

There are sections of our rural distribution network nearing design life and requiring replacement in the near future. This offers an opportunity to optimise our network through alternative approaches to supplying power to customers in affected areas. Our work so far on our algorithm for optimising network topology has shown that strategically placed SPSs may be a cost effective alternative to replacing certain sections of our rural distribution network.

8.4.8 Building alliances and knowledge networks

We are working with innovators and thought leaders to build knowledge and industry insights. The microgrid projects are helping us learn from peers and better understand the capabilities of new technologies and industry participants and meet the evolving needs of consumers.

As emerging technologies impact every element of the energy value-chain and knowledge becomes increasingly specialised, we are:

» partnering with industry to explore new opportunities, discuss changing requirements and trial new technologies
» talking to customers about their changing expectations of our business and the ways they want to access energy
» sharing these insights with regulators and policy makers.

Part of alliance building includes working with project proponents to support and where appropriate facilitate, the development of projects focused on sustainability and the integration of new technologies into our network. Examples of this include:

» sustainable retirement accommodation development project in the South West
» aggregated large-scale solar power station project in metropolitan Perth
» solar + battery for Commercial and Industrial (C&I) customers trial
» residential subdivisions contemplating incorporating storage in the distribution network
» a sustainability focused residential microgrid-based in the south-west of our network.

The principal measure of success is being acknowledged as having positioned our business as an active supporter of new technologies. To achieve this we need to proactively revise connection processes, rules and standards to encourage the integration of new technologies into the existing network.

8.4.9 Fusesaver

Customers located at the periphery of rural distribution networks typically experience the largest number of supply interruptions, usually caused by faults that are not permanent in nature. The expanse of bare overhead networks in these areas are more exposed to wildlife, vegetation and wind borne debris which are the cause of the vast majority of fuse operations.

The Fusesaver is an Australian product developed about five years ago and used throughout the country. The device is a small, extremely fast operating, autonomous, medium voltage switching device designed to open for a short pre-set period before reclosing. The design is intended to operate and open before the fuse blows. During the open time the temporary fault cause will clear allowing the network supply to be successfully restored when the Fusesaver closes.

A Western Power study of the causes of fuse operations revealed that up to 80 per cent of fuse operations on the rural overhead networks can be attributed to these temporary type fault causes. With this device's potential to reduce unnecessary fuse replacements, we have embarked on trialling the technology at 26 locations most prone to fuse operation, to assess the potential benefits of reducing operating expenditure and improving network performance.

The trial is expected to be finalised after a year of network exposure and monitoring, at the end of 2017.

APPENDIX A: GLOSSARY

Term	Explanation
AA3	Access Arrangement 3 - regulatory period from 1 July 2012 to 30 June 2017.
Access Code	Electricity Networks Access Code 2004
AEMO	Australian Energy Market Operator
APR	Transmission and Distribution Annual Planning Report
AQP	Applications and Queuing Policy
CAG	Competing Applications Group
CAGR	Compound Annual Growth Rate
CBD	Central Business District
Coincident	Load value on a substation that is at a maximum when other substations in a group or the network have a maximum value.
DER	Distributed Energy Resource
Degraded condition	As applied to transformers, this assessment indicates that the asset's condition will continue to deteriorate, although this may be slowed by remedial action. This assessment is not associated with any reduction in short-term reliability.
DRD	Department of Regional Development (Western Australia)
DM	Demand management
DSOC	Declared Sent-Out Capacity - maximum amount of power that a generator has contracted with Western Power to export to the network.
DTC	Distribution Transfer Capacity
EMR	Electricity Market Review
EP Act	Western Australian Environmental Protection Act 1986
EPA	Environmental Protection Authority (Western Australia)
EPBC Act	Commonwealth Environment Protection and Biodiversity Conservation Act 1999
ERA	Economic Regulation Authority (Western Australia)
ETAC	Electricity Transfer Access Contract
EV	Electric vehicles
HV	High Voltage
IMO	Independent Market Operator (Western Australia)
IRCR	Individual Reserve Capacity Requirement
IWC	Interconnection Works Contract
kA	Kiloampere (measure of electrical current)
kV	Kilovolt (measure of electrical potential)
kWh	Kilowatt hour (measure of electrical energy)
LGA	Local Government Authority
LV	Low Voltage
MVA	Megavolt Ampere (measure of electrical demand)
MW	Megawatt (measure of the active component of electrical demand)
MWEP	Mid West Energy Project

Term	Explanation
N-0	A Technical Rules planning criterion allowing the loss of load following any single contingency event under peak demand conditions.
N-1	A Technical Rules planning criterion allowing no loss of load following any single contingency event under peak demand conditions.
N-1-1	A Technical Rules planning criterion allowing for no loss of load following two concurrent contingency events (generally one planned, one unplanned) at 80% peak load, allowing for generation redespatch.
N-2	A Technical Rules planning criterion allowing no loss of load following any two concurrent contingency events under peak demand conditions.
NCMT	Network Capacity Mapping Tool
NCR	Network Capacity Rollback or Normal Cyclic Rating
NCR Criterion	A Technical Rules planning criterion allowing a substation to be loaded higher than its N-1 capacity and permitting the disconnection of a limited number of customers for up to 12 hours. NCR substations are restricted to the Perth metropolitan area due to the practical limitations in deploying a rapid response spare transformer within 12 hours.
NCS	Network Control Services
NDP	Network Development Plan
NEM	National Electricity Market
NFIT	New Facilities Investment Test
NIEIR	National Institute of Economic and Industry Research
NMP	Network Management Plan
Non-coincident	Load value on a substation that is not a maximum when other substations in a group or the network have a maximum value.
PoE	Probability of Exceedance - the percentage of time that an actual value will exceed the forecast value. For example, under a 'PoE10' forecast, the actual value is expected to exceed the forecast once every ten years.
PV	Photovoltaic (solar cell)
DEE	Department of the Environment and Energy
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
SWIN	South West Interconnected Network - the transmission and distribution components of the electricity system.
SWIS	South West Interconnected System - the entire electricity system including all of the generators.
Technical Rules	ERA-administered definitions of network planning criteria and technical requirements for plant connected to the network.
TUF	Transformer Utilisation Factor
WEM	Wholesale Electricity Market
Western Power network	The element of the South West Interconnected Network that is owned and operated by Western Power.
WPR	Works Planning Report

APPENDIX B: CROSS-REFERENCE OF WESTERN POWER PLANNING REGIONS

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
Goldfields-Esperance		
	Coolgardie (S)	Country Goldfields 33 kV
	Dundas (S)	
	Esperance (S)	
	Kalgoorlie/Boulder (C)	Country Goldfields 11 kV
	Laverton (S)	
	Leonora (S)	
	Menzies (S)	
	Ngaanyatjarraku (S)	
Great Southern		
	Albany (C)	Country South / Great Southern study area
	Broomehill-Tambellup (S)	Country South / Great Southern study area
	Cranbrook (S)	Country South / Great Southern study area
	Denmark (S)	Country South / Great Southern study area
	Gnowangerup (S)	Country South / Great Southern study area
	Jerramungup (S)	Country South / Great Southern study area

Sources

1. Regions listed on Department of Regional Development and Lands website as at 27 August 2015 (www.drd.wa.gov.au)
2. WA Local Councils listed in publication "Local Government Authorities contained in each Regional Development Commission region" as at 18 December 2012 (www.drd.wa.gov.au/Publications/Documents/Local_Governments_Regional_Development_Councils.pdf)

Note:

Local Government Areas that do not have a matching Western Power Planning Region / Sector / Cluster are not supplied by the SWIN and are not listed.

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
	Katanning (S)	Country South / Great Southern study area
	Kent (S)	Country South / Great Southern study area
	Kojonup (S)	Country South / Great Southern study area
	Plantagenet (S)	Country South / Great Southern study area
	Ravensthorpe (S)	Country South / Great Southern study area
	Woodanilling (S)	Country South / Great Southern study area
Mid West		
	Carnamah (S)	
	Chapman Valley (S)	Country North 11 kV, Country North 33 kV
	Coorow (S)	
	Cue (S)	
	Greater Geraldton (C))	Country North 11 kV, Country North 33 kV
	Irwin (S)	Country North 33 kV
	Meekatharra (S)	
	Mingenew (S)	Country North 33 kV
	Morawa (S)	Country North 33 kV
	Mount Magnet (S)	
	Murchison (S)	
	Northampton (S)	Country North 6.6 kV, Country North 33 kV
	Perenjori (S)	Country North 33 kV
	Sandstone (S)	
	Three Springs (S)	Country North 33 kV
	Wiluna (S)	
	Yalgoo (S)	
Peel		
	Boddington (S)	Country East 22 kV
	Mandurah (C)	Metro South 22 kV (C)
	Murray (S)	Metro South 22 kV (C), Country South

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
	Serpentine-Jarrahdale (S)	Metro South 22 kV (A)
	Waroona (S)	Country South / South West study area
South West		
	Augusta-Margaret River (S)	Country South / South West study area
	Boyup Brook (S)	Country South / South West study area
	Bridgetown-Greenbushes (S)	Country South / South West study area
	Bunbury (C)	Country South / South West study area
	Busselton (S)	Country South / South West study area
	Capel (S)	Country South / South West study area
	Collie (S)	Country South / South West study area
	Dardanup (S)	Country South / South West study area
	Donnybrook-Balingup (S)	Country South / South West study area
	Harvey (S)	Country South / South West study area
	Manjimup (S)	Country South / South West study area
	Nannup (S)	Country South / South West study area
Wheatbelt		
	Beverley (S)	Country South, Country East 22 kV
	Brookton (S)	Country South
	Bruce Rock (S)	Country East 22 kV, Country East 33 kV
	Chittering (S)	Metro North 22 kV (B)
	Corrigin (S)	Country South, Country East 33 kV
	Cuballing (S)	Country South
	Cunderdin (S)	Country East 22 kV
	Dalwallinu (S)	Country North 33 kV
	Dandaragan (S)	Country North 33 kV
	Dowerin (S)	Country North 33 kV, Country East 22 kV
	Dumbleyung (S)	Country South, Country East 33 kV
	Gingin (S)	Metro North 22 kV (B)

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
	Goomalling (S)	Country East 22 kV, Country North 33 kV
	Kellerberrin (S)	Country East 22 kV
	Kondinin (S)	Country East 33 kV
	Koorda (S)	Country North 33 kV, Country East 22 kV
	Kulin (S)	Country East 33 kV
	Lake Grace (S)	Country East 33 kV, Country South
	Merredin (S)	Country East 22 kV
	Moora (S)	Country North 33 kV
	Mount Marshall (S)	Country East 22 kV
	Mukinbudin (S)	Country East 22 kV
	Narembeen (S)	Country East 33 kV
	Narrogin Shire (S)	Country South
	Narrogin Town (T)	Country South
	Northam (S)	Country East 22 kV
	Nungarin (S)	Country East 22 kV, Country East 33 kV
	Pingelly (S)	Country South
	Quairading (S)	Country East 22 kV
	Tammin (S)	Country East 22 kV
	Toodyay (S)	Metro North 22 kV (B), Country East 22 kV
	Trayning (S)	Country East 22 kV
	Victoria Plains (S)	Country North 33 kV
	Wagin (S)	Country South
	Wandering (S)	Country South
	West Arthur (S)	Country South
	Westonia (S)	Country East 22 kV, Country East 33 kV
	Wickepin (S)	Country South, Country East 33 kV
	Williams (S)	Country South
	Wongan-Ballidu (S)	Country North 33 kV

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
	Wyalkatchem (S)	Country East 22 kV
	Yilgarn (S)	Country East 33 kV
	York (S)	Country East 22 kV
Perth Metropolitan		
	Armadale (C)	Metro South 22 kV (A)
	Bassendean (T)	Metro North 22 kV (A)
	Bayswater (C)	CBD, Metro North 11 kV (B), Metro North 22 kV (A)
	Belmont (C)	Metro South 22 kV (B), Metro East 22 kV
	Cambridge (T)	Metro North 6.6 kV, Metro North 11 kV (B), CBD
	Canning (C)	Metro South 22 kV (A), Metro South 22 kV (B)
	Claremont (T)	Metro North 11 kV (A), Metro North 6.6 kV
	Cockburn (C)	Metro South 22 kV (B)
	Cottesloe (T)	Metro North 11 kV (A)
	East Fremantle (T)	Metro South 11 kV (B), Metro South 22 kV (A)
	Fremantle (C)	Metro South 11 kV (B), Metro South 22 kV (A)
	Gosnells (C)	Metro South 22 kV (A), Metro South 22 kV (B)
	Joondalup (C)	Metro North 22 kV (B)
	Kalamunda (S)	Metro South 22 kV (B), Metro East 22 kV
	Kwinana (T)	Metro South 22 kV (C)
	Melville (C)	Metro South 22 kV (B)
	Mosman Park (T)	Metro North 11 kV (A)
	Mundaring (S)	Metro East 22 kV
	Nedlands (C)	Metro North 11 kV (A), Metro North 6.6 kV
	Peppermint Grove (S)	Metro North 11 kV (A)
	Perth (C)	Metro CBD, Metro North 6.6 kV
	Rockingham (C)	Metro South 22 kV (C)
	South Perth (C)	Metro South 11 kV (A), Metro South 22 kV (B)
	Stirling (C)	Metro North 11 kV (B), Metro North 22 kV (A), Metro North 22 kV (B), Metro North 6.6 kV,

Perth Metropolitan / DRD Region	Local Government Area (by Perth Metropolitan / DRD Region)	Western Power Planning Region / Sector / Cluster
	Subiaco (C)	Metro North 6.6 kV, Metro CBD
	Swan (C)	Metro East 22 kV, Metro North 22 kV (A), Metro North 22 kV (B)
	Victoria Park (T)	Metro South 11 kV (A), Metro South 6.6 kV, Metro South 22 kV (B)
	Vincent (T)	CBD, Metro North 11 kV (B)
	Wanneroo (C)	Metro North 22 kV (B)

APPENDIX C: ESTIMATED MAXIMUM SHORT CIRCUIT LEVELS

This appendix lists maximum short circuit levels forecast at each of the Western Power network's major nodes. This information should only be used as an approximate guide.

The short circuit level calculations were determined in accordance with the following:

- The IEC 60909 method was used for the calculations; this is the source standards upon which the current Australian and New Zealand standards (AS/NZS 3851) is based.
- For maximum fault levels, the C factor (as defined by IEC 60909) is set at 1.1 pu at the fault bus.
- Zero fault impedance is assumed.
- All generation machines and step-up transformers are turned on.
- All lines are assumed in service.
- The expected fault current shown is IKSS.[48]

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
Bunbury load area			
APJ - ALCOA Pinjarra	330.0	15.18	13.05
APJ - ALCOA Pinjarra	132.0	14.84	14.91
BDP - Binningup Desalination Plant	132.0	11.58	9.36
BSI - Barrack Silicon Smelter	132.0	15.12	13.58
BSN - Busselton	132.0	2.60	3.03
BSN - Busselton	66.0	4.30	5.26
BSN - Busselton	22.0	3.44	3.91
BUH - Bunbury Harbour	132.0	9.93	9.62
BUH - Bunbury Harbour	22.0	5.49	5.39
CAP - Capel	66.0	5.36	4.80
CAP - Capel	22.0	3.65	4.12
CLP - Coolup	66.0	1.02	0.70
CLP - Coolup	22.0	1.74	2.22
KEM - Kemerton	330.0	21.50	19.87
KEM - Kemerton	132.0	20.68	22.62
KMP - Kemerton Power	330.0	20.46	18.79
MR - Margaret River	66.0	1.57	1.83
MR - Margaret River	22.0	2.54	3.11
MRR - Marriott Road	132.0	17.13	16.63
MRR - Marriott Road	22.0	5.46	5.53

[48] AC component of the initial symmetrical short circuit current which occurs directly after the initiation of the fault (RMS value).

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
OLY - Oakley	330.0	17.32	15.05
PIC - Picton	132.0	11.72	11.50
PIC - Picton	66.0	9.76	12.22
PIC - Picton	22.0	6.07	6.19
WSD - Westralian Sands	66.0	5.20	4.81
Cannington load area			
BEC - Beckenham	132.0	26.93	28.96
BEL - Belmont	132.0	19.04	18.42
BEL - Belmont	22.0	4.35	0.97
BTY - Bentley	132.0	19.61	17.19
BTY - Bentley	22.0	4.40	0.98
CL - Clarence St	66.0	8.95	7.05
CL - Clarence St	11.0	7.80	8.05
COL - Collier	66.0	9.00	7.06
COL - Collier	11.0	9.39	10.65
CT - Cannington terminal	132.0	28.72	30.81
CT - Cannington terminal	66.0	14.64	17.64
KDL - Kewdale	132.0	18.41	16.95
KDL - Kewdale	23.3	4.38	0.96
KNL - Kenwick Link	330.0	16.57	15.76
KNL - Kenwick Link	132.0	26.14	26.87
RVE - Rivervale	132.0	17.88	16.58
RVE - Rivervale	22.0	4.57	0.98
TLN - Tomlinson Road	66.0	9.84	8.43
TT - Tate Street	66.0	12.51	13.51
TT - Tate Street	22.0	4.94	6.34
VP - Victoria Pak	66.0	12.00	12.43
WE - Welshpool	132.0	21.30	21.19
WE - Welshpool	22.0	4.50	1.01
East Country load area			
BDE - Bandee	66.0	1.79	1.52
BNY - Bounty	132.0	0.67	0.85
BNY - Bounty	33.0	1.74	2.49
CAR - Carrabin	66.0	1.25	0.96
CAR - Carrabin	22.0	1.67	1.99

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
CGT - Collgar terminal	220.0	2.97	3.94
CGW - Collgar Wind Farm	220.0	2.97	3.94
CUN - Cunderdin	66.0	1.13	0.82
CUN - Cunderdin	22.0	1.78	2.28
KDN - Kondinin	220.0	2.92	2.95
KDN - Kondinin	132.0	1.51	1.67
KDN - Kondinin	33.0	2.85	4.43
KEL - Kellerberrin	66.0	1.17	0.90
KEL - Kellerberrin	22.0	1.42	1.91
MDP - Merredin power station	132.0	5.18	6.86
MER - Merredin	132.0	4.56	5.51
MER - Merredin	66.0	3.66	4.94
MER - Merredin	22.0	3.30	0.16
MRT - Merredin terminal	220.0	3.19	4.05
MRT - Merredin terminal	132.0	5.18	6.86
MW - Mundaring Weir	66.0	3.73	2.60
MW - Mundaring Weir	6.6	7.39	8.36
NOR - Northam	132.0	5.25	4.87
NOR - Northam	66.0	4.62	4.30
NOR - Northam	22.0	5.55	5.13
SVY - Sawyers Valley 132kV	132.0	7.84	6.92
SVY - Sawyers Valley 132kV	22.0	4.13	4.56
SX - Southern Cross	66.0	0.62	0.44
SX - Southern Cross	33.0	1.85	1.38
WUN - Wundowie	66.0	2.89	2.05
WUN - Wundowie	22.0	2.66	3.10
YER - Yerbillon	66.0	1.15	0.87
YLN - Yilgarn	220.0	2.49	2.50
YLN - Yilgarn	33.0	4.12	5.47
Eastern Goldfields load area			
BKF - Black Flag	132.0	2.97	3.11
BKF - Black Flag	33.0	5.38	5.15
BLD - Boulder	132.0	5.80	7.12
BLD - Boulder	33.0	6.77	9.27
JAN - Jan	132.0	2.12	2.20

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
LEF - Lefroy	132.0	2.36	2.59
PCY - Piccadilly St	132.0	5.73	7.20
PCY - Piccadilly St	11.0	10.97	2.08
PKS - Parkeston Substation	132.0	5.59	6.62
WKT - West Kalgoorlie	220.0	3.01	3.83
WKT - West Kalgoorlie	132.0	5.91	7.99
WKT - West Kalgoorlie	33.0	4.01	5.54
WKT - West Kalgoorlie	11.0	10.87	1.85
WMK - Western Mining Kambalda	132.0	2.97	3.31
WMS - Western Mining Smelter	132.0	4.95	5.47
East Perth and CBD load area			
CK - Cook Street	132.0	23.05	23.01
CK - Cook Street	11.0	10.09	2.93
EP - East Perth	132.0	25.28	27.35
EP - East Perth	66.0	5.65	7.07
EP - East Perth	20.6	9.21	1.04
F - Forrest Ave	66.0	5.22	5.65
F - Forrest Ave	11.0	10.24	12.09
HAY - Hay Street	132.0	21.83	22.75
HAY - Hay Street	11.0	11.51	2.18
JTE - Joel Terrace 132kV	132.0	24.91	26.17
JTE - Joel Terrace 132kV	11.0	8.62	1.84
MIL - Milligan Street	132.0	19.31	20.95
MIL - Milligan Street	11.0	12.85	2.18
NP - North Perth	132.0	20.41	19.99
NP - North Perth	11.0	8.98	1.84
SUM - Summers Street	132.0	25.00	26.62
W - Wellington Street	66.0	5.39	6.05
W - Wellington Street	11.0	8.39	9.53
Guildford load area			
D - Darlington	132.0	13.63	12.80
D - Darlington	22.0	4.27	0.94
FFD - Forrestfield	132.0	13.33	13.20
FFD - Forrestfield	22.0	5.76	1.05
GLT - Guildford terminal	330.0	16.64	16.14

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
GLT - Guildford terminal	132.0	23.05	25.10
HZM - Hazelmere	132.0	22.44	23.86
HZM - Hazelmere	22.0	4.36	0.96
K - Kalamunda	132.0	11.35	10.86
K - Kalamunda	22.0	5.62	1.05
MDY - Munday	132.0	13.27	13.13
MDY - Munday	23.3	5.23	0.99
MJ - Midland Junction	132.0	21.62	23.27
MJ - Midland Junction	23.3	4.84	1.32
Kwinana load area			
AFM - Australian Fused Materials	132.0	20.72	18.95
AKW - ALCOA Kwinana	132.0	32.24	34.64
BHK - Broken Hill Kwinana	66.0	7.16	7.98
BP - British Petroleum	66.0	7.31	7.97
BPR - B.P. Refinery	132.0	26.71	27.72
CBP - CSBP	132.0	24.94	24.62
CKB - Cockburn Power	132.0	31.82	34.68
HIS - Hismelt	132.0	23.58	23.02
KDP - Kwinana Desalination Plant	132.0	28.42	30.27
KMK - Kerr McGee Kwinana	132.0	29.46	32.53
KND - Kwinana Donaldson Road	132.0	28.33	31.28
KPP - Kwinana Power Partnership	132.0	27.59	29.31
KW - Kwinana	330.0	20.72	21.11
KW - Kwinana	132.0	32.59	35.32
KW - Kwinana	66.0	7.61	9.11
MED - Medina	132.0	20.09	17.11
MED - Medina	22.0	4.38	1.05
MSR - Mason Road	132.0	29.46	32.53
MSR - Mason Road	22.0	4.57	0.96
PLD - Parklands	132.0	11.08	10.74
RO - Rockingham	132.0	19.91	18.93
RO - Rockingham	22.0	6.27	1.03
TPP - Tiwest Pigment Plant	132.0	29.46	32.53
WM - Western Mining	132.0	23.14	22.05

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
Mandurah load area			
MH - Mandurah	132.0	10.53	10.10
MH - Mandurah	22.0	4.25	0.97
MSS - Meadow Springs	132.0	11.08	10.75
MSS - Meadow Springs	22.0	4.25	0.97
PNJ - Pinjarra	132	14.05	12.78
PNJ - Pinjarra	22.0	4.31	4.61
WAI - Waikiki	132.0	15.23	13.75
WAI - Waikiki	22.0	4.34	0.95
Muja load area			
ALB - Albany	132.0	1.63	1.89
ALB - Albany	22.0	6.20	6.95
BGM - Boddington Gold Mine	132.0	10.01	10.03
BLW - Bluewaters terminal	330.0	22.11	21.09
BNP - Beenup	132.0	1.26	1.25
BNP - Beenup	22.0	2.26	2.77
BOD - Boddington	132.0	10.01	10.03
BOD - Boddington	22.0	4.95	6.81
BTN - Bridgetown	132.0	4.75	4.92
BTN - Bridgetown	22.0	4.61	6.03
BWP - Bluewaters power station	330.0	22.11	21.09
CO - Collie	66.0	2.14	1.66
CO - Collie	22.0	2.43	3.25
CPS - Collie power station terminal	330.0	20.03	19.09
KAT - Katanning	66.0	1.47	1.70
KAT - Katanning	22.0	2.62	2.54
KOJ - Kojonup	132.0	3.98	4.33
KOJ - Kojonup	66.0	2.62	2.87
KOJ - Kojonup	22.0	4.37	5.91
LWT - Landwehr terminal	330.0	16.68	15.80
MBR - Mount Barker	132.0	1.67	1.75
MBR - Mount Barker	22.0	3.72	4.95
MJP - Manjimup	132.0	3.10	3.18
MJP - Manjimup	22.0	4.17	5.64
MU - Muja	330.0	22.55	21.92

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
MU - Muja	220.0	9.06	10.20
MU - Muja	132.0	23.07	27.49
MU - Muja	66.0	3.73	3.77
NGN - Narrogin	66.0	1.22	1.59
NGN - Narrogin	22.0	2.27	2.73
NGS - Narrogin South	220.0	3.68	3.05
NGS - Narrogin South	66.0	1.24	1.63
SHO - Shotts	330.0	21.77	20.82
WAG - Wagin	66.0	1.20	1.04
WAG - Wagin	22.0	1.39	1.84
WAPL - Worsley Alumina Pty Ltd	132.0	15.06	17.89
WAPL - Worsley Alumina Pty Ltd	66.0	4.05	4.56
WCG - Worsley Co Generation	132.0	15.17	17.97
WCL - Western Colleries Limited	132.0	15.85	13.59
WGP - Wagerup	132.0	8.61	6.95
WGP - Wagerup	22.0	4.01	4.35
WLT - Wells terminal	330.0	7.14	6.74
WLT - Wells terminal	132.0	11.45	12.36
WOR - Worsley	132.0	15.17	17.97
Neerabup terminal load area			
CKN - Clarkson	132.0	15.21	13.50
CKN - Clarkson	22.0	5.07	0.98
JDP - Joondalup	132.0	18.75	18.33
JDP - Joondalup	23.3	4.46	0.98
LDE - Landsdale	132.0	17.55	17.28
LDE - Landsdale	22.0	4.36	0.98
MUC - Muchea	132.0	17.76	15.44
MUC - Muchea	22.0	4.36	0.85
MUL - Mullaloo	132.0	19.28	19.69
MUL - Mullaloo	22.0	4.27	0.95
PBY - Padbury	132.0	17.65	16.65
PBY - Padbury	22.0	4.35	0.95
WGA - Wangara	132	17.04	16.46
WGA - Wangara	22.0	4.31	0.99
WNO - Wanneroo	132.0	20.19	20.01
WNO - Wanneroo	22.0	4.51	1.03

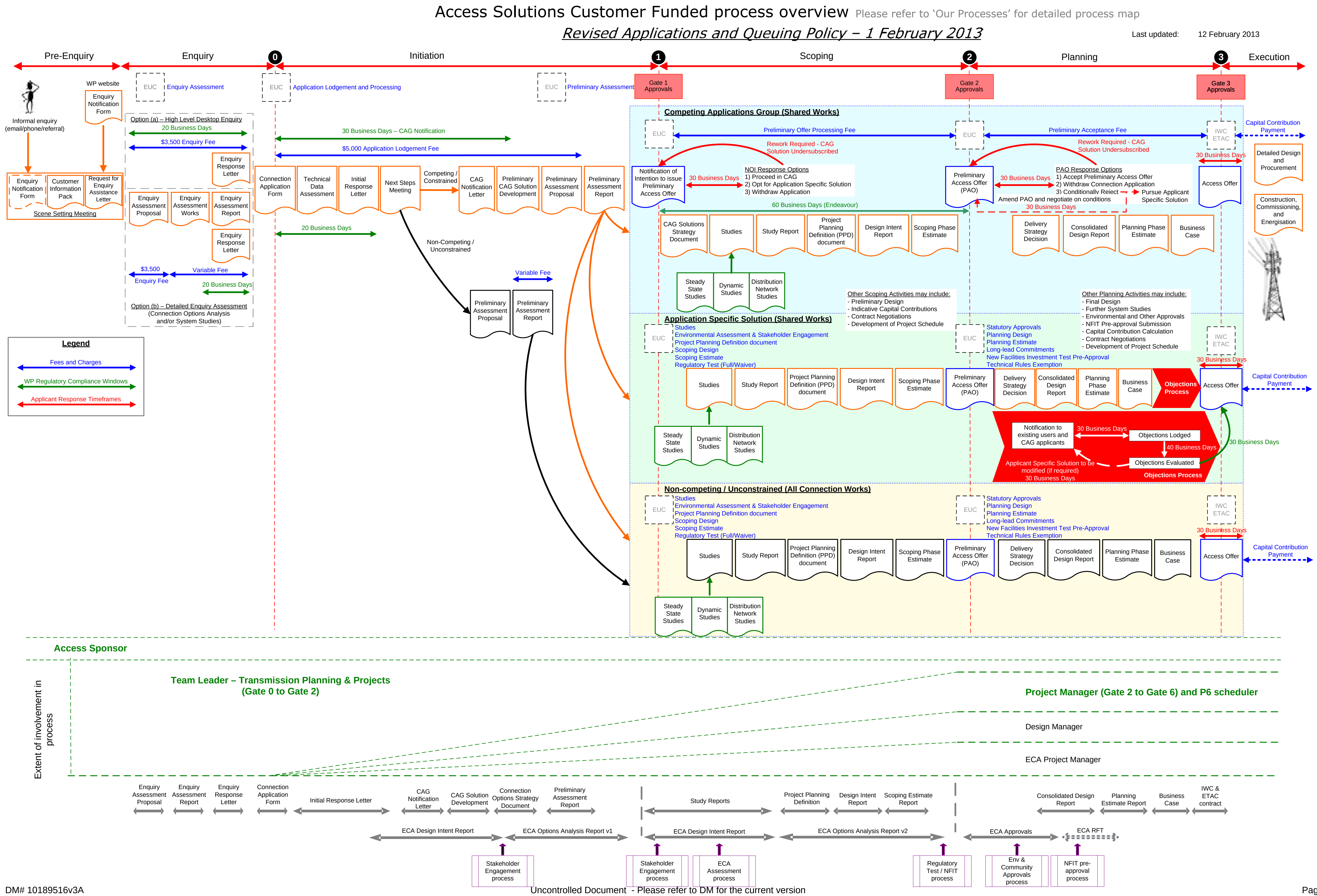
Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
North Country load area			
CPN - Chapman	132.0	3.76	4.45
CPN - Chapman	11.0	9.03	10.01
CTB - Cataby	132.0	5.96	5.92
DUR - Durlacher Street	33.0	7.28	8.55
DUR - Durlacher Street	11.0	7.50	10.84
EMD - Emu Downs	132.0	4.49	4.63
ENB - Eneabba	132.0	5.67	5.23
ENB - Eneabba	33.0	3.04	4.09
GGV - Golden Grove	132.0	1.26	1.57
GRS - Greenough River Solar Farm	132.0	6.98	8.34
GTN - Geraldton	132.0	4.14	4.94
GTN - Geraldton	33.0	6.79	9.39
KMC - Kerr McGee Cataby	132.0	5.96	5.92
KRA - Karara Mine	330.0	2.09	3.03
MBA - Mumbida Wind Farm	132.0	4.78	5.18
MGA - Mungarra	132.0	6.97	8.34
MOR - Moora	132.0	2.75	1.84
MOR - Moora	33.0	2.78	3.24
RAN - Rangeway	132.0	3.77	4.49
RAN - Rangeway	11.0	9.07	11.96
RGN - Regans	132.0	5.74	5.59
RGN - Regans	33.0	3.10	3.67
RGN - Regans	22.0	4.19	1.01
TS - Three Springs	132.0	7.63	8.02
TS - Three Springs	36.3	1.87	1.79
TST - Three Springs terminal	330.0	3.18	3.61
TST - Three Springs terminal	132.0	7.53	8.28
WWF - Walkaway Windfarm	132.0	5.10	5.65
Northern terminal load area			
A - Arkana	132.0	19.78	19.85
A - Arkana	22.0	5.68	1.07
BCH - Beechboro	132.0	19.56	18.78
BCH - Beechboro	22.0	4.40	1.01
BCT - Balcatta	132.0	18.94	18.05

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
BCT - Balcatta	22.0	4.36	1.00
EDG - Edgewater	132.0	19.28	19.69
GNN - Newgen Neerabup	330.0	13.30	13.30
H - Hadfields	132.0	16.55	15.57
H - Hadfields	22.0	4.38	0.99
HBK - Henley Brook	132.0	12.81	10.53
HBK - Henley Brook	23.3	4.28	0.98
KMM - Kerr McGee Muchea	132.0	14.19	11.28
MA - Manning Street	132.0	17.88	17.36
MA - Manning Street	11.0	11.59	2.03
MLA - Mount Lawley	132.0	21.25	22.08
MLG - Malaga	132.0	28.80	33.80
MLG - Malaga	23.3	5.36	0.97
MO - Morley	132.0	17.35	18.38
MO - Morley	11.0	11.99	2.00
NB - North Beach	132.0	19.41	19.30
NB - North Beach	22.0	5.65	1.03
NBT - Neerabup terminal	330.0	13.68	13.69
NBT - Neerabup terminal	132.0	21.44	21.56
NOW- Nowergup	132.0	15.21	13.50
NT - Northern terminal	330.0	17.95	18.26
NT - Northern terminal	132.0	28.80	33.80
OP - Osborne Park	132.0	19.58	19.89
OP - Osborne Park	11.0	11.84	1.94
PJR - Pinjar Power Station	132.0	29.39	32.25
Y - Yokine	132	19.41	19.44
Y - Yokine	11.0	11.77	2.00
YP - Yanchep	132.0	14.98	13.22
YP - Yanchep	22.0	4.47	1.00
South Fremantle load area			
AMT - Amherst	132.0	20.08	17.13
AMT - Amherst	22.0	4.38	0.99
APM - Australian Paper Mills	66.0	9.37	8.05
APM - Australian Paper Mills	22.0	4.74	6.12
BIB - Bibra Lake	132.0	21.73	18.70

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
BIB - Bibra Lake	22.0	4.38	0.97
E - Edmund Street	66.0	10.92	10.54
E - Edmund Street	11.0	8.14	8.14
MYR - Myaree	66.0	8.76	7.45
MYR - Myaree	22.0	4.62	4.90
NF - North Fremantle	66.0	10.19	9.08
NF - North Fremantle	11.00	7.72	8.61
OC - OConnor	66.0	9.94	9.81
OC - OConnor	22	4.79	5.10
SF - South Fremantle	132.0	27.74	25.11
SF - South Fremantle	66.0	14.08	17.29
SF - South Fremantle	20.6	14.60	1.04
Southern terminal load area			
BYF - Byford	132.0	13.48	11.77
BYF - Byford	22.0	6.25	1.01
CC - Cockburn Cement	132.0	26.32	24.18
CC - Cockburn Cement	22.0	6.98	0.97
CCL - Cockburn Cement Ltd	132.0	26.18	24.06
CVE - Canning Vale	132.0	19.14	18.75
CVE - Canning Vale	22.0	4.51	0.98
G - Gosnells	132.0	22.68	21.72
G - Gosnells	22.0	5.91	1.03
GNI - Glen Iris	132.0	27.33	28.98
MDN - Maddington	132.0	22.97	20.86
MDN - Maddington	22.0	4.40	0.96
MUR - Murdoch	132.0	25.46	23.43
MUR - Murdoch	22.0	4.75	0.94
RTN - Riverton	132.0	20.75	18.03
RTN - Riverton	22.0	4.86	0.99
SNR - Southern River	132.0	20.85	19.12
SNR - Southern River	22.0	4.38	0.99
ST - Southern terminal	330	22.01	22.83
ST - Southern terminal	132.0	35.16	38.85
WLN - Willeton	132.0	19.81	19.32
WLN - Willeton	22.0	4.36	0.96

Substation	Voltage (kV)	Fault level - 3 phase (kA)	Fault level - 1 phase (kA)
Western terminal load area			
CTE - Cottesloe	132.0	18.42	15.76
CTE - Cottesloe	11.0	8.72	1.82
HE - Herdsman Parade	66.0	8.35	6.69
HE - Herdsman Parade	6.6	11.45	12.76
MCE - Medical Centre	66.0	9.86	10.88
MCE - Medical Centre	11.0	10.94	1.82
N - Nedlands	66.0	10.96	11.32
N - Nedlands	6.6	11.80	12.73
SP - Shenton Park	66.0	11.46	13.01
SP - Shenton Park	6.6	11.80	13.02
SPK - Shenton Park	132.0	20.63	20.06
SPK - Shenton Park	11.0	9.60	1.91
U - University	66	9.90	10.12
U - University	6.6	11.46	13.21
WD - Wembley Downs	66.0	9.62	8.06
WD - Wembley Downs	11.0	9.48	10.72
WT - Western terminal	132.0	21.90	22.02
WT - Western terminal	66.0	13.21	16.74

APPENDIX D: CONNECTION APPLICATION PROCESS MAPS



APPENDIX E: HISTORICAL PEAK DEMAND

The SWIS annual peak demand comprises the total demand from:

- Western Power network distribution customers
- Western Power network transmission customers
- customers consuming electricity without using the Western Power network
- transmission and distribution losses.

As shown in Table 54, the contribution to the SWIS annual peak demand by these different customer types has varied over the last five years. For example, the contribution by Western Power network transmission loads has steadily increased from 7.7% in 2011/12 to 9.1% in 2015/16.

SWIS peak demand growth rates in 2013/14 and 2014/15 were below the long-term growth rate of 3.8% from 1979/80 to 2015/16 (inclusive). These years recorded peak demand growth of -0.18% and 1.74% respectively. A significant component of this difference is attributable to the reduced impact of lower temperatures on load demand (as was the case in the 2013/14 and 2014/15 summers), changing consumer behaviour (including the impact of the Individual Reserve Capacity Requirement mechanism, which is discussed in Section E.1[49]) and increased regional demand diversity. In 2015/16 the SWIS peak demand demonstrated a growth rate that exceeded the long-term growth rate recording a peak demand growth of 6.3%. The diminishing influences associated with both changing consumer behaviour and regional diversity are still applicable to the 2015/16 peak demand growth but it was the impact of a significant heatwave discussed in the next section 3.5.1.1 during the 2015/16 summer that was predominately responsible for this increase.

[49] The Individual Reserve Capacity Requirement mechanism allocates the cost of capacity credits acquired to market customers, thus encouraging customers to reduce their demand during peak periods. Further information on this mechanism appears in the Deferred 2015 Electricity Statement of Opportunities for the WEM (Australian Energy Market Operator - June 2016) (pp 26 - 27).

Table 54: SWIS system peak load contribution

		2011/12	2012/13	2013/14	2014/15	2015/16
Contribution to SWIS annual peak demand by Western Power network distribution loads	MW	3,381	3,251	3,144	3,176	3,515
	%	83.4	81.9	79.3	78.8	82.0
Contribution to SWIS annual peak demand by Western Power network transmission loads	MW	313	360	370	429	391
	%	7.7	9.1	9.3	10.6	9.1
Contribution to SWIS annual peak demand by non-Western Power network loads and losses	MW	360	359	449	427	380
	%	8.9	9.0	11.3	10.6	8.9
SWIS annual peak demand[51]	MW	4,054	3,970	3,963	4,032	4,286
	%	100	100	100	100	100

[50] This is the SWIS annual peak demand value (5 minute average). The instantaneous 2015/16 SWIS annual peak demand set a new record and was 4,304 MW.

Peak demand impact factors

The 2015/16 annual peak demand occurred during a five day heatwave from 7 to 11 February 2016. Recorded on Monday 8 February 2016 at 5:27 pm both the SWIS and the Western Power network set new annual peak demand records breaking the previous records set back in 2011/12. The maximum temperature on the peak demand day was 42.6°C. While not the hottest summer day recorded in the last five summers[51] this heatwave is regarded as the most significant of the 23 heatwaves that have occurred since 2011/12.

Table 55 lists and ranks the 23 heatwaves that have occurred since 2011/12 by descending average maximum temperature.

Table 55: Heatwave ranking based on average maximum temperature - summers 2011/12 to 2015/16

Ranking	Summer period	Heatwave length (days)	Heatwave category*	Average max. temp °C
1	2013/14	3	PH or WE	40.73
2	2015/16	5	WD	40.62
3	2011/12	4	PH or WE	40.00
4	2012/13	7	PH or WE	39.44
5	2012/13	5	WD	39.34
6	2015/16	3	PH or WE	39.10
7	2011/12	6	PH or WE	38.87
8	2014/15	3	PH or WE	38.87
9	2012/13	3	WD	38.83
10	2015/16	3	WD	38.70
11	2015/16	3	PH or WE	38.63
12	2013/14	5	PH or WE	38.32
13	2011/12	3	PH or WE	38.23
14	2013/14	6	WD	38.18
15	2012/13	3	PH or WE	37.87
16	2014/15	5	WD	37.60
17	2013/14	3	PH or WE	37.60
18	2011/12	3	PH or WE	37.10

[51] Summer refers to the period 1 December to 31 March (inclusive).

Table 55: Heatwave ranking based on average maximum temperature - summers 2011/12 to 2015/16 (continued)

Ranking	Summer period	Heatwave length (days)	Heatwave category*	Average max. temp °C
19	2011/12	3	WD	37.03
20	2015/16	3	PH or WE	36.33
21	2011/12	3	PH or WE	36.20
22	2011/12	4	WD	36.05
23	2013/14	6	WD	35.82

* PH or WE refers to a heatwave that occurred predominately over a weekend or public holiday period. WD refers to a heatwave that occurred predominately over a period of weekdays in a normal working week.

Figure 40 compares and ranks in descending order the maximum daily temperatures for the summers 2011/12 to 2015/16.

Figure 40: Ranking of summer period maximum daily temperatures - 2011/12 to 2015/16[52]

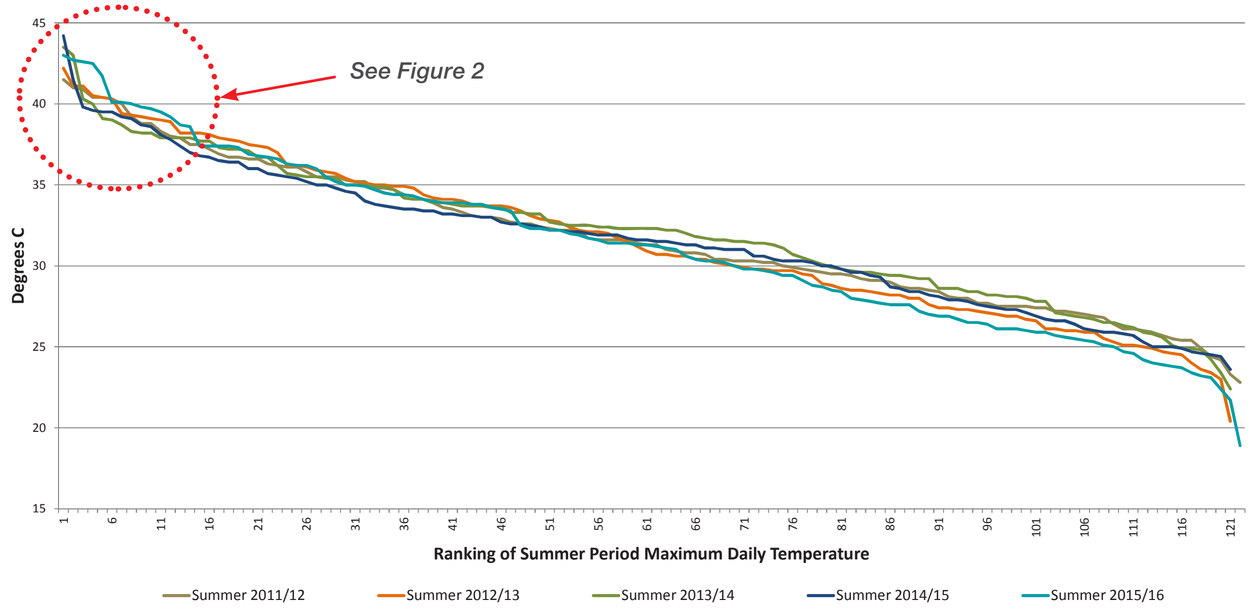
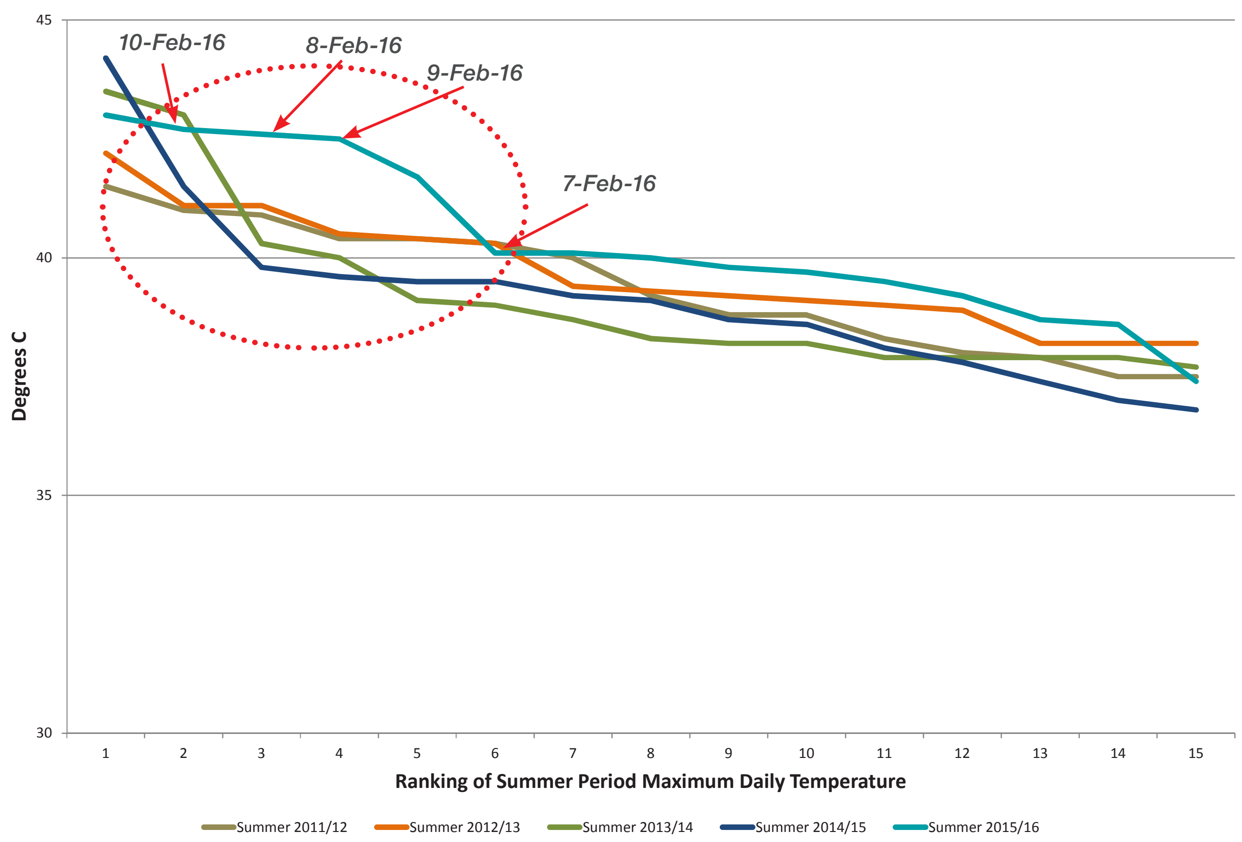


Figure 41 shows the 15 highest ranked maximum daily temperatures for the summers 2011/12 to 2015/16.

[52] Number of days in the 2011/12 and 2015/16 summers = 122. The 2012/13, 2013/14 and 2014/15 summers had 121 days.

Figure 41: 15 highest ranked maximum daily temperatures for the summers 2011/12 to 2015/16.



A review of table 55, figures 40 and 41 coupled together with an investigation of additional weather data for the last five summers provides the following observations, insights and conclusions about the 2015/16 summer period and its temperature response effect on the 2015/16 annual peak demand.

» Heatwaves that occur predominately over a public holiday or weekend typically have significantly less temperature response effect on load demand than heatwaves that fall predominately on weekdays within a normal working week.

» Although ranked 2nd in table 55 the 7-11 February 2016 heatwave is regarded as the most significant heatwave in the last five summers. Its temperature response effect surpassed that of the heatwave ranked 1st due mainly to:
  ¤ Longer duration
  ¤ Predominately a weekday occurrence
  ¤ Average maximum temperature only about 0.1°C less
  ¤ Wind direction characteristics

» Figure 41 shows that, in general, the 15 hottest days in the 2015/16 summer were hotter than the hottest days in the other four summers.

» Figure 40 shows that, other than the 15 hottest days, the remainder of the 2015/16 summer was equal to or cooler than the other four summers.

» The red circle in figure 41 shows the ranking positions of the four hottest days in the 7-11 February 2016 heatwave. This is a clear indicator of the intensity of this heatwave compared to heatwaves experienced in the other four summers.

The strong correlation between temperature and load demand is a statistical relationship that is well established. That is, other than a short time lag, the hotter it gets the higher the load demand. However, the generally reliable afternoon sea breeze that prevails over much of the more densely populated and developed areas of the south-western landmass supplied by the Western Power network will typically drop the ambient temperature on the hottest of summer's day. This drop in temperature is often rapid and significant and is usually followed (after a lag of 1-2 hour or so) by a stabilisation and/or reduction in load demand. The following explains the effects of wind direction on ambient temperature and its subsequent effect on the Western Power network load demand displayed during the 7-11 February 2016 heatwave.

» The three hottest days in the 7-11 February 2016 heatwave were the 8th, 9th and 10th. Maximum temperatures recorded on these days were 42.6°C, 42.5°C and 42.7°C respectively and the Western Power network load demand values recorded on these days were 3906 MW, 3798 MW and 3713 MW respectively.

» Although the maximum daily temperatures for these hottest days were almost identical the wind direction characteristics were not.
  ¤ On 8th February 2016 (peak day) from roughly 2 am to 4 pm the wind direction was from the NE quadrant. It oscillated between the northerly and easterly direction but, in general, had an easterly bias. It changed direction to the SW quadrant after 4 pm. The impact of this late sea breeze sustained the ambient temperature above 40°C until about 6 pm well into the usual daily peak demand period resulting in the 2015/16 annual peak demand and a new record for the Western Power network.
  ¤ The 9th and 10th February 2016 experienced a wind direction change from the NE to the SW quadrant much earlier in the day (i.e. between midday and 1 pm). This earlier sea breeze had a dramatic effect on the afternoon ambient temperatures experienced on both days. For example, on 9th February the ambient temperature had dropped below 40°C by 3 pm and was below 37°C during the daily peak period. On the 10th February the ambient temperature dropped to below 37°C at around 1 pm, increased slightly to just above 38°C by 4 pm before dropping again to below 37°C during the daily peak period.
  ¤ Although the Western Power network daily peak demands recorded on both the 9th and 10th February were lower than that recorded on the 8th February it is worth noting that their recorded values still exceeded the previous record of 3,694 MW set back in 2011/12. This reinforces the ranking given to the 7-11 February 2016 heatwave and shows that the temperature response demonstrated by the load demand on these days supports the claim that it is the most significant heatwave that has occurred since 2011/12.

On the 14th March 2016 another significant temperature response effect worthy of a mention occurred. Its significance is explained by the following.

» The Western Power network peak demand recorded on this day was 3902 MW, just 4 MW short of the 2015/16 annual peak demand recorded on 8th February 2016.

» Other than the three hottest days in the 7-11 February 2016 heatwave mentioned above this is the only other day in the 2015/16 summer to have a peak demand that exceeded the previous record set back in 2011/12. The remaining days (118) of the 2015/16 summer were more than 73 MW lower than this previous record.

» It was not part of a heatwave.

» Maximum daily temperature was 40.1°C. Ranked the 7th hottest in the 2015/16 summer.

» Minimum overnight temperature was 26.3°C. This was just short of being the highest minimum overnight temperature in the 2015/16 summer.

» The previous day's maximum daily temperature was 39.7ºC.
» From roughly 2 am on the 13th March 2016 to after midnight on the 14th March 2016 (almost 2 full days) the wind direction was from the NE quadrant predominately oscillating between a north-easterly to easterly direction. The absence of a sea breeze on this day and the compounding temperature conditions mentioned above sustained the ambient temperature above 39oC until about 6 pm well into the usual daily peak demand period resulting in the high daily peak demand recorded.

The difference between the 2015/16 and 2014/15 Western Power network annual peak demand was 301 MW. This is quantified as follows:

» About 107 MW (35%) is attributed to load growth.
» About 194 MW (65%) is attributed to temperature response.

An evaluation of the difference's temperature response component estimates that the effect of the 2015/16 summer period on the Western Power network annual peak demand was equivalent to a PoE 20 summer. That is, estimated as a one year in five occurrence. This is substantiated by the following:

» The 2015/16 annual peak demand fell short of the 2014/15 central PoE 10 forecast value by 56 MW.
» Mentioned previously in Section 3, the volatility range due to temperature response is calculated to be +250 MW. This volatility range is represented by the difference between the PoE 10 and PoE 50 forecasts and, therefore, implies that 6.25 MW equates to one PoE increment. The 56 MW shortfall converts to about 9 PoE equivalents. This can be rounded to 10 PoE equivalents. PoE 10 + 10 PoE equivalents = PoE 20.
» Also, the previous annual peak demand records for the SWIS and the Western Power network were set back in 2011/12. This was only 4 years ago but is statistically consistent with a one in five year frequency.

Modelling of solar radiance data[53] estimated the impact of PV at the time of the 2015/16 annual peak demand to be about 90MW. This is consistent with the amount of PV impact that was incorporated in to the 2014/15 forecasts. The data also confirms that there was no impairment to PV output at the time of the annual peak demand and in fact shows that clear skies prevailed for most of the day.

The SWIS and the Western Power network are regarded as being summer peaking systems. This has been the case since the early 1990's when they both switched from being winter to summer peaking. The main driver behind this shift is credited to the overwhelming residential adoption of refrigerated air conditioning. For this reason the Annual Planning Report has not, in recent editions, discussed aspects associated with winter demand peaks.

However, the BoM has reported that the 2016 winter period has produced the coldest winter days for at least the last two decades. Mindful of the possible interest that may be associated with the effects of colder than usual winter temperatures on load demand and aware that the 2016 winter demand peaks for both the SWIS and the Western Power network set new records breaking the previous records set back in 2014, it was considered important to provide some winter peak demand statistics in this year's Annual Planning Report.

Table 56 presents a summary of winter peak demand statistics for the last five years.

[53] Western Power has installed a number of solar radiance measuring devices in strategic network locations.

Table 56: Summary of the winter peak demand - 2012 to 2016

		2012	2013	2014	2015	2016
Western Power network winter peak demand (5 minute average)	MW	2,990	2,987	3,110	3,046	3,249
	%	90.3	90.6	90.7	89.9	90.0
Non-Western Power network loads and losses	MW	320	311	319	344	360
	%	9.7	9.4	9.3	10.1	10.0
SWIS winter peak demand (5 minute average)	MW	3,310	3,298	3,429	3,390	3,609
	%	100	100	100	100	100
SWIS winter peak demand (instantaneous)	MW	3,331	3,313	3,445	3,404	3,629

A comparison of the corresponding annual peak (i.e. summer) and winter peak demands for the last five years shows that the peak demands recorded for both the SWIS and the Western Power network are significantly higher in summer than in winter and indicates no bias towards convergence or divergence over the period.

Table 57 shows the difference between the corresponding annual peak (i.e. summer) and winter peak demands for the last five years.

Table 57: Peak Demand difference between summer and winter

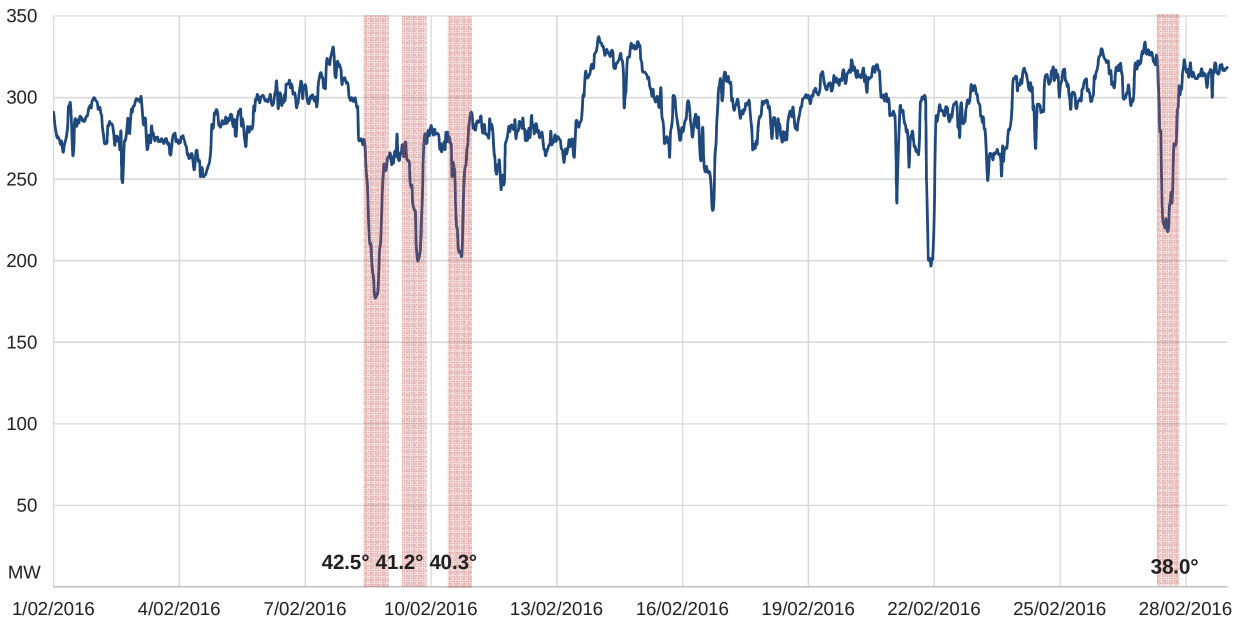
		2011/12 (summer) 2012 (winter)	2012/13 (summer) 2013 (winter)	2013/14 (summer) 2014 (winter)	2014/15 (summer) 2015 (winter)	2015/16 (summer) 2016 (winter)
Western Power network summer - winter peak demand (5 minute average)	MW	704	624	404	559	657
Non-Western Power network loads and losses: summer - winter	MW	40	48	130	83	20
SWIS summer - winter peak demand (5 minute average)	MW	744	672	534	642	677
SWIS summer - winter peak demand (instantaneous)	MW	737	671	537	655	675

E.1 Peak demand impact - Individual Reserve Capacity Requirement mechanism

AEMO operates the Individual Reserve Capacity Requirement mechanism to provide market customers with an incentive to reduce consumption at times of system peak. A lower at-peak consumption will reduce the capacity costs allocated to them to fund the capacity of the SWIS in the following capacity year.

AEMO's Deferred 2015 Electricity Statement of Opportunities for the WEM reported that the load demand reduction impact (on both the SWIS and the Western Power network) of the 57 most responsive customer loads during February 2016, including the 2015/16 annual peak demand, was 77 MW. Figure 42 summarises these responses, highlighting the afternoons of the three hottest days in the 7-11 February 2016 heatwave, and the daily maximum temperatures of each. The response to the IRCR mechanism for the last five years is shown in Table 58.

Figure 42: IRCR impact on SWIS annual demand peak – February 2016[54]



[54] Source: Deferred 2015 Electricity Statement of Opportunities for the WEM (Australian Energy Market Operator - June 2016) (pp 26 - 27).

Table 58: IRCR response on annual peak demand days – summers 2011/12 to 2015/16

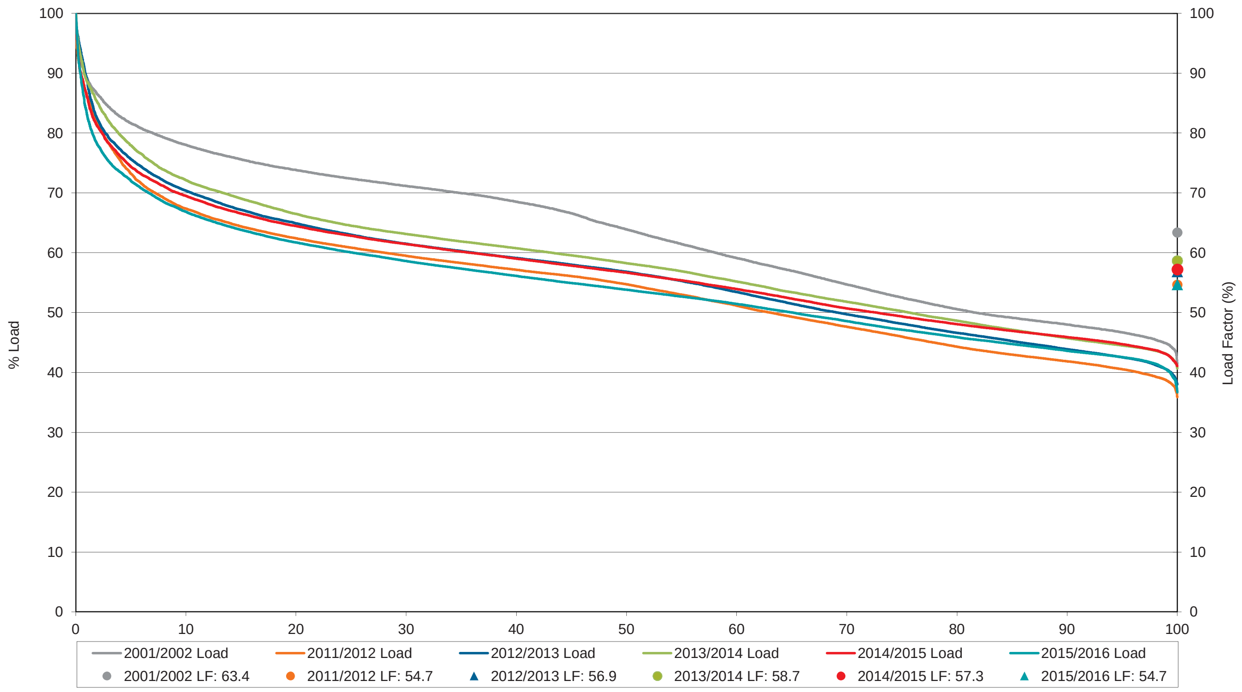
Date	Estimated IRCR reduction (MW)	Number of customers responding
8 February 2016	77	57
5 January 2015	42	20
20 January 2014	50	44
12 February 2013	65	59
25 January 2012	50	59

E.2 Peak demand trend

The historical load duration curves[55] in Figure 43 present an alternative perspective on how the SWIS peak demand is changing over time. In the context of network investment, it is important to emphasise that recent changes in consumer behaviour have had greater influence over the coincidental SWIS peak demand and less influence on the totalised non-coincidental substation peaks. For this reason, Western Power will continue to monitor each substation's non-coincidental peak demand annually to mitigate emerging issues at the substation level.

[55] A load duration curve shows the percentage of the year that the demand supplied from the SWIS exceeded a given level.

Figure 43: SWIS load duration curves



E.3 Comparison of peak demand forecasts - 2013/14 to 2015/16

As shown in Figure 44, the Central PoE 50 Western Power network annual peak demand forecast developed in 2015/16 displays a similar trend growth rate but is slightly higher than those developed in 2013/14 and 2014/15 which were almost identical. This modest increase reflects the ability of our current forecasting methods to identify and adjust for specific changes in annual peak demand between consecutive years. For example, the 2015/16 forecast displays an adjustment for growth that is consistent with the amount of change that occurred between the 2015/16 and 2014/15 annual peak demands that was attributed to growth (i.e. 107 MW) and was discussed earlier.

In addition to this growth component the following factors also contributed to the variation between the forecasts:

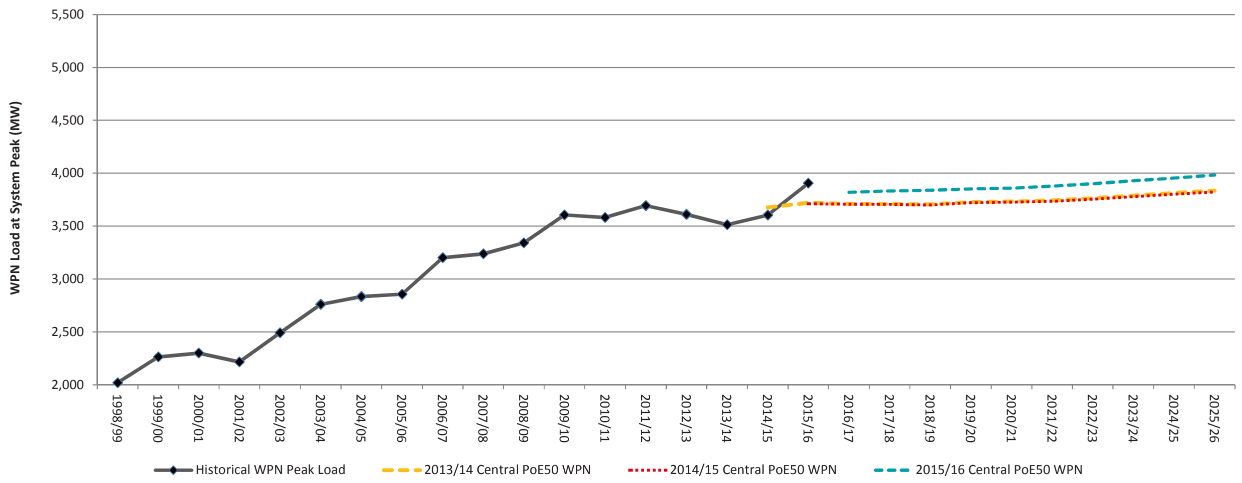
PV impact
Since 2010/11, Western Power has adjusted the annual peak demand forecast to reflect the expected impact of solar photovoltaic power systems (PVs) on both the SWIS and the Western Power network. The expected upward impact of PVs applied to these forecasts (i.e. 2013/14, 2014/15 and 2015/16) are consistent, reflecting our increased understanding of this technology.

Trending change
Additional to the trend increase discussed above Figure 44 shows that these forecasts (i.e. 2013/14, 2014/15 and 2015/16) share a similar trend growth rate (CAGR) for the period 2016/17 to 2025/26. There is, however, a slight difference. The CAGR for the 2015/16 forecast for this period is 0.5% compared to the 2013/14 and 2014/15 forecasts that displayed a CAGR of about 0.4% each. This difference reflects a slight strengthening in future load demand but is considered statistically immaterial.

Revised block loads
As part of the annual forecasting process, Western Power consults with relevant stakeholders to determine the most likely timing and load demand of new projects proposing to connect to the Western Power network. Following this year's consultation, the block loads incorporated into the 2015/16 forecast were adjusted. However, the overall difference in demand between the block loads added to the 2014/15 and 2015/16 forecasts was negligible.

Probability of Exceedance change
With additional historical data for 2015/16, the 10% PoE adjustment was recalculated to reflect the level of confidence in the underlying growth trend. The recalculated 10% PoE adjustment applied to the 2015/16 forecast has decreased slightly, due to changes in risk measurement methods based on the underlying sources of risk (e.g. temperature variation versus short-term changes in industrial production) rather than indicating increased certainty. Alternative risk methods (e.g. extreme value theory) are currently being assessed.

Figure 44: Comparison of Western Power network annual peak demand forecasts - 2013/14 to 2015/16[56]



[56] Supporting data is presented in tabular form in Table 61.

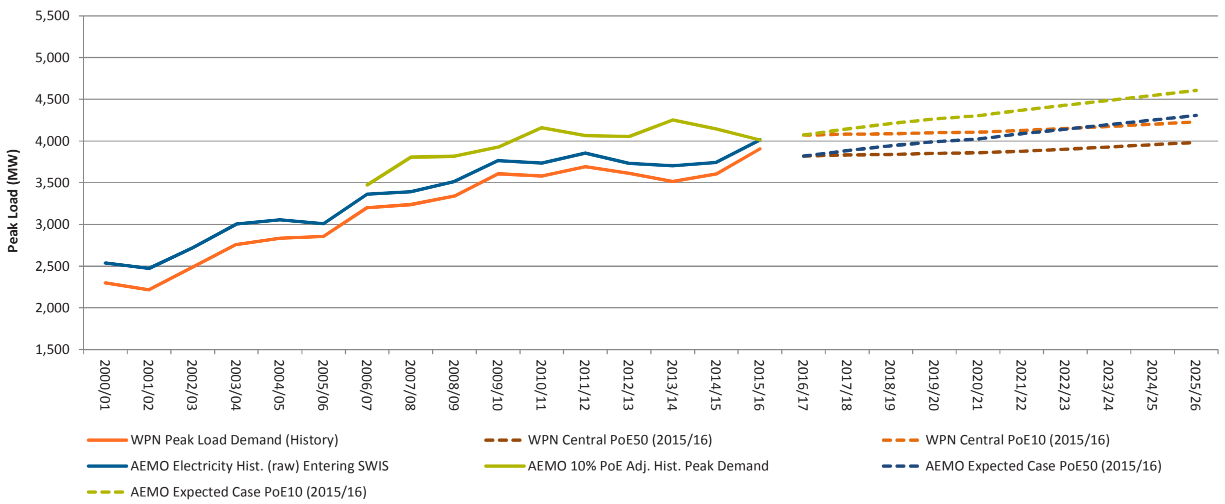
2015/16 annual peak demand forecasts: differences between Western Power and AEMO

The AEMO produces annual central peak demand forecasts (10% PoE, 50% PoE and 90% PoE) for the SWIS. These represent the peak or maximum sent-out electricity entering the SWIS, which includes all SWIS customers and all losses. They are therefore higher than the corresponding central Western Power network annual peak demand forecasts, but suitable for comparison and validation purposes.

Figure 45 compares the two sets of forecasts.

The difference between the 10% PoE and 50% PoE forecasts published by the AEMO differs marginally from the corresponding difference between our forecasts. This is partly due to the treatment of the last ten years of peak demand observations, which have been weather-adjusted by the AEMO[58]. The two central 50% PoE forecasts diverge steadily over the forecast period, with the AEMO predicting a higher CAGR of 1.3%, compared to our forecast of 0.5%. The central 10% PoE forecasts show a similar relationship.

Figure 45: Comparison of Western Power and AEMO 2015/16 annual central peak demand forecasts[58]



In reconciling the difference in compound annual growth rates, it should be noted that the AEMO has almost doubled its trend outlook from last year (0.7%), while Western Power's has increased only slightly (~0.4%). Both organisations share similar outlooks, predicting future growth rate ranges below historic levels.

Comparing both organisations' unadjusted historical data from 2000/01 to 2015/16 yields differences ranging between 107 MW and 257 MW, the AEMO's being the greater of the two. The difference between the two central 50% PoE forecasts over the forecast period ranges from 0 MW to 323 MW, the AEMO's again exceeding ours. Although the forecast range of difference exceeds the historical range of difference, they are sufficiently close to suggest that this close correspondence will continue.

In conjunction with improved forecast performance (discussed in E.4), this increases our confidence in the accuracy of its recent forecasts and the methodology that generated them.

In this context, Western Power predicts lower growth than the AEMO, towards the lower end of the likely range. Should actual peak demand be closer to the AEMO's forecast, Western Power will re-evaluate its approach. There is adequate network capacity to support either organisation's peak demand forecast.

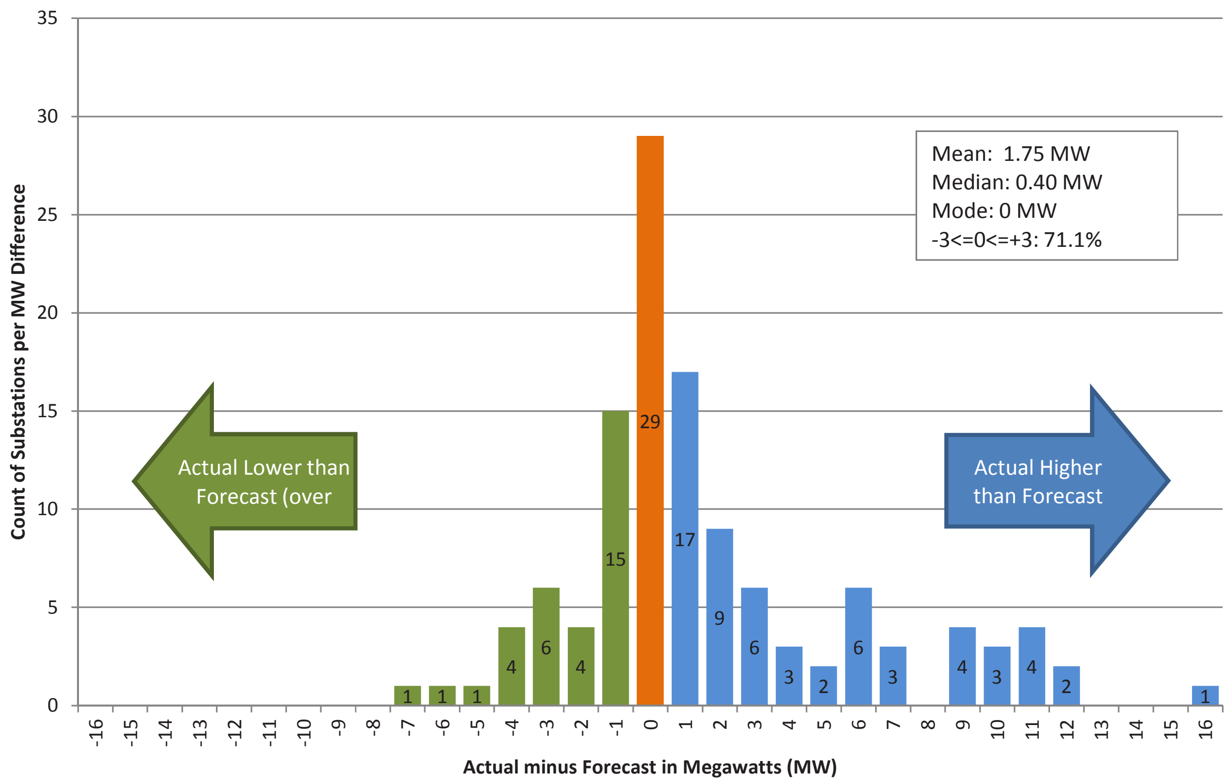
[57] Source: the Deferred 2015 Electricity Statement of Opportunities for the WEM (Australian Energy Market Operator - June 2016) (Appendix E p77).
[58] Supporting data is presented in tabular form in Table 61.

E.4 Peak demand forecast validation

In addition to commissioning an independent review of its forecasts, Western Power reviews forecasting accuracy for each substation annually.

Figure 46 shows the close correspondence between the non-coincident Western Power network 2014/15 central PoE 50 substation annual peak demand forecasts and the corresponding actual peak demand measured for each substation during the 2015/16 summer.

Figure 46: Non-coincident Western Power network central PoE 50 substation variance - 2014/15 forecast and 2015/16 actual



The 2015/16 actual annual peak demand measured for the majority of Western Power-owned substations was within ±3 MW (71.1%[59]) of the corresponding non-coincident 2014/15 central PoE 50 forecast values. This is a moderate deterioration over last year's forecast accuracy, which indicated that 78.5%[60] of substations were within ±3 MW of the corresponding 2013/14 forecast value. However, it was a substantial improvement over the previous year's forecast accuracy which indicated that 63.5%[61] of substations were within ±3 MW of the corresponding 2012/13 forecast value. Most of the exceptions, in this year's review, resulted from the zone substation forecast being too low rather than too high.

The main reason for this under forecasting bias can be explained by the following:

» Our forecast accuracy is an overall measure of each substation's actual annual peak demand to the corresponding non-coincident central PoE 50 forecast value for the substation.
» Western Power evaluats the 2015/16 summer period's temperature response effect on the Western Power network annual peak demand as being equivalent to a PoE 20 summer.
» Comparing an actual annual peak demand value resulting from a PoE 20 summer to a PoE 50 forecast value was expected to result in an overall forecast accuracy for 2015/16 that showed a bias towards under forecasting.

The average forecast error (i.e. actual > forecast) per Western Power-owned substation was 1.75 MW.

To ensure that the internal verification was not distorted by an extraordinarily hot or cold day, Western Power reviewed the temperature and related data for all SWIS peak days from 1998/99 to 2015/16 (inclusive), as summarised in Table 59.

[59] Equates to 86/121 Western Power-owned substations within ±3 MW.
[60] Equates to 95/121 Western Power-owned substations within ±3 MW.
[61] Equates to 76/120 Western Power-owned substations within ±3 MW.

Table 59: Peak day temperature data - 1998/99 to 2015/16

Western Power network annual peak demand (MW)	Date	Max daily temp (°C)	Min o/night temp (°C)	Ave daily temp (°C)	Number of hotter days	Day of week
2,019	8/2/1999	38.1	23.9	31.0	3	Monday
2,263	8/3/2000	37.6	25.4	31.5	4	Wednesday
2,299	6/3/2001	37.8	21.2	29.5	5	Tuesday
2,216	31/1/2002	36.1	22.3	29.2	4	Thursday
2,491	10/3/2003	40.1	23.9	32.0	3	Monday
2,760	17/2/2004	40.1	27.3	33.7	3	Tuesday
2,834	15/2/2005	41.1	22.8	32.0	0	Tuesday
2,856	7/3/2006	36.4	20.2	28.3	6	Tuesday
3,201	7/3/2007	41.7	21.6	31.7	0	Wednesday
3,238	11/2/2008	37.1	23.9	30.5	9	Monday
3,341	11/2/2009	38.4	24.9	31.7	3	Wednesday
3,607	25/2/2010	40.8	24.5	32.7	3	Thursday
3,581	25/2/2011	38.7	24.6	31.7	6	Friday
3,694	25/1/2012	40.0	24.8	32.4	6	Wednesday
3,611	12/2/2013	41.1	26.6	33.9	1	Tuesday
3,514	20/1/2014	38.7	20.6	29.7	6	Monday
3,605	5/1/2015	44.2	21.5	32.9	0	Monday
3,906	8/2/2016	42.6	20.7	31.7	2	Monday

Table 60: Comparison of Western Power network central PoE 50 annual peak demand forecasts - 2013/14 to 2015/16

Year	Peak load (historical)	2015/16 – PoE 50	2014/15 – PoE 50	2013/14 – PoE 50
1998/99	2,019			
1999/00	2,263			
2000/01	2,299			
2001/02	2,216			
2002/03	2,491			
2003/04	2,760			
2004/05	2,834			
2005/06	2,856			
2006/07	3,201			
2007/08	3,238			
2008/09	3,341			
2009/10	3,607			
2010/11	3,581			
2011/12	3,694			
2012/13	3,611			
2013/14	3,514			
2014/15	3,605			3,677
2015/16	3,906		3,712	3,720
2016/17		3,819	3,707	3,710
2017/18		3,832	3,705	3,709
2018/19		3,839	3,700	3,705
2019/20		3,852	3,721	3,727
2020/21		3,859	3,727	3,734
2021/22		3,878	3,734	3,742
2022/23		3,902	3,755	3,765
2023/24		3,928	3,778	3,788
2024/25		3,955	3,801	3,812
2025/26		3,983	3,823	3,836

Table 61: Comparison of 2015/16 central/expected case annual peak demand forecasts - Western Power network and AEMO

	AEMO						Western Power Network		
Year	Electricity (raw) entering SWIS (historical)	Adjusted historical peak demand – PoE 10	Expected case – PoE 10 (2015/16)	Expected case – PoE 50 (2015/16)	Expected case – PoE 90 (2015/16)	Peak load demand (historical)	Central PoE 10 (2015/16)	Central PoE 50 (2015/16)	Central PoE 90 (2015/16)
2000/01	2,538					2,299			
2001/02	2,473					2,216			
2002/03	2,721					2,491			
2003/04	3,004					2,760			
2004/05	3,055					2,834			
2005/06	3,008					2,856			
2006/07	3,364	3,474				3,201			
2007/08	3,392	3,806				3,238			
2008/09	3,515	3,818				3,341			
2009/10	3,766	3,926				3,607			
2010/11	3,735	4,160				3,581			
2011/12	3,857	4,064				3,694			
2012/13	3,732	4,054				3,611			
2013/14	3,702	4,252				3,514			
2014/15	3,744	4,145				3,605			
2015/16	4,013	4,013				3,906			
2016/17			4,073	3,819	3,598		4,071	3,819	3,567
2017/18			4,145	3,885	3,659		4,083	3,832	3,582
2018/19			4,209	3,943	3,712		4,085	3,839	3,592
2019/20			4,263	3,991	3,755		4,099	3,852	3,606

Table 61: Comparison of 2015/16 central/expected case annual peak demand forecasts - Western Power network and AEMO (continued)

	AEMO						Western Power Network		
Year	Electricity (raw) entering SWIS (historical)	Adjusted historical peak demand – PoE 10	Expected case – PoE 10 (2015/16)	Expected case – PoE 50 (2015/16)	Expected case – PoE 90 (2015/16)	Peak load demand (historical)	Central PoE 10 (2015/16)	Central PoE 50 (2015/16)	Central PoE 90 (2015/16)
2020/21			4,303	4,023	3,779		4,106	3,859	3,613
2021/22			4,371	4,089	3,843		4,125	3,878	3,631
2022/23			4,428	4,141	3,891		4,148	3,902	3,655
2023/24			4,487	4,197	3,944		4,175	3,928	3,681
2024/25			4,545	4,250	3,992		4,202	3,955	3,709
2025/26			4,606	4,306	4,045		4,230	3,983	3,736

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