Transmission System Plan - 2022

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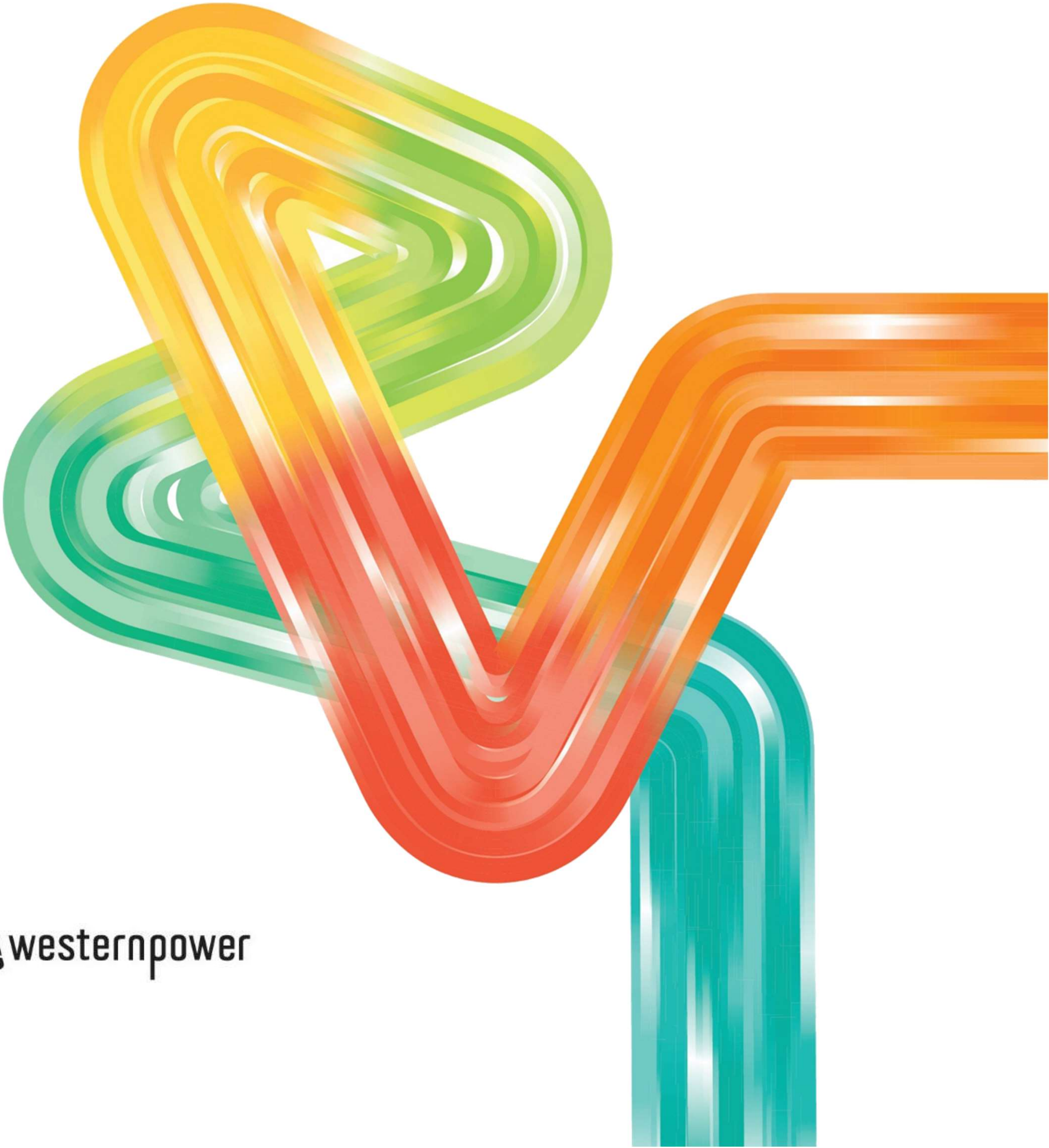

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The information contained in the TSP2022 is subject to annual review. Western Power is obligated to publish future editions by 1 October each year, in accordance with the *Wholesale Electricity Market Rules (1 September 2022).*

Further Information

https://www.westernpower.com.au/network-opportunity-map/

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Contents

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition	Term	Definition
AA	Access Arrangement	NCR	Normal Cyclic Rating
AA4	Access Agreement 4	NCS	Network Control Service
AEMO	Australian Energy Market Operator	NOM	Network Opportunity Map
AOS2021	Alternative Options Strategy 2021	NQRS	Network Quality and Reliability of Supply Code
APC	Annual Planning Cycle	NSP	Network Service Provider
BTM	Behind-the-meter	PASA	Projected Assessment of System Adequacy
CAG	Competing Applications Group	PoE	Probability of Exceedance
CBD	Central Business District	PTA	Public Transport Authority
DER	Distributed Energy Resources	Pu	Per Unit
DPV	Distributed Photovoltaic	PV	Photovoltaic
ELPS	Eastern Goldfields Load Permissive Scheme	RCP	Reserve Capacity Price
ELT2	Electricity Transmission Licence	RFP	Request for Proposal
EMR	Electricity Market Reform	RIS	Required In Service
EMT	Electro-magnetic Transient	ROI	Registration of Interest
EOI	Expression of Interest	RTS	Real-Time Simulator
EPWA	Energy Policy WA	SMI	System Minutes Interrupted
ERA	Economic Regulation Authority	SPS	Standalone Power System
ESOO	Electricity Statement of Opportunities	SSB	Service Standard Benchmarks
EV	Electric Vehicle	SVC	Static VAR Compensator
GIA	Generator Interim Access	SWIN	South West Interconnected Network
kV	Kilovolt	SWIS	South West Interconnected System
kW	Kilowatt	TR	Technical Rules
MDT	Minimum Demand Threshold	TSP	Transmission System Plan
MRWA	Main Roads WA	VAR	Volt Ampere Reactive
MVA	Mega Volt Ampere	WAMPAC	Wide Area Monitoring Protection and Control
MVAr	Mega Var	WEM	Wholesale Electricity Market
MW	Megawatt	WOSP	Whole of System Plan
MWh	Megawatt hours		
NCR	Non-Cyclic Rating		

1 Executive Summary

The Transmission System Plan (TSP) is a new obligation for Western Power under section 4.5B of the Wholesale Electricity Market (WEM) Rules and is required to be published annually by 1 October. For the inaugural TSP, a draft version is to be published by 1 October with the final version to be published by 1 February 2023. This document is the inaugural version of the TSP.

The purpose of the TSP is to present a 10-year forward plan for investment in the transmission network to deliver efficient, safe, secure and reliable energy to consumers while operating within an increasingly complex and dynamic energy landscape. The TSP sets out potential investment opportunities, including alternatives to network augmentation, to alleviate identified network constraints to maintain power system security and reliability on the South West Interconnected System (SWIS) transmission network over a 10-year time horizon, whilst maximising the long-term interests of consumers. The inaugural TSP covers the 2020/21 to 2029/30 planning horizon to enable alignment with Western Power's latest demand forecast[1] and maintain continuity with existing network planning activities. As Western Power transitions to a forward-planning model, it is anticipated that future TSP's will cover the 10-year forward period.

The energy sector is undergoing transformational change driven by a combination of economic factors, disruptive new technologies and changing consumer behaviours which are present challenges and opportunities to drive the development of the SWIS. Demand for cleaner and alternative energy sources is changing the traditional electricity value chain. Increasingly, the network is acting as a platform for customers to choose how they want their electricity supplied and delivered. Increased penetration of renewable generation, and the displacement of traditional synchronous generation, has led to major changes to both ends of the electricity supply chain.

With more than 2,000 MW[2] of Distributed Photovoltaic (DPV) capacity connected to the SWIS, managing power system security and reliability during periods of low operational demand is increasingly challenging, particularly in relation with voltage management and system stability.

The State Government's Energy Transformation Strategy 2019-2021[3] implemented reforms to address these challenges and plan for an orderly transition to a future where more renewables can be integrated into the system while continuing to deliver safe, secure, reliable and affordable electricity to consumers. As part of these reforms, access to Western Power's network is transitioning from an unconstrained to a constrained framework where generators will receive more equitable access to the network and network utilisation is efficiently maximised, allowing better management of power system security and maintaining downward pressure on wholesale electricity prices. This will be effected through the implementation of a security-constrained economic dispatch process in the WEM where generator dispatch is subject to network constraints.

The new WEM is currently targeting the 1 October 2023. The new WEM will deliver real-time and ex-post information about the impact of network constraints. Future TSPs will be able to use this and other market information to analyse trade-offs between efficient network investment and market costs, enabling Western Power to present network investment options that maximise benefits to the system. In addition, future TSPs are expected to provide greater insights into the performance of the transmission system and emerging constraints, solutions and opportunities.

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1 Current demand forecasts were produced in 2020, looking forward from the period 2020/21 to 2029/30

2 DPV capacity as of March 2022 - https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf?la=en&hash=AF5B0EE73B9AAD4C0A246F264BC72AB6

3 More information about the Strategy is available on Energy Policy WA's website: https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy

Climate change commitments of net zero by 2050 (globally) and national emission reduction targets of 43 per cent[4] by 2030 are driving action by industry in Western Australia and across the globe. Decarbonisation activities include:

- Electrification of-major industry (transportation and gas supplied processes)
- New loads from alternative energy sources such as hydrogen and ammonia
- Commercial and residential vehicle electrification
- Government policy commitments (e.g., Synergy coal fired generation retirement)
- Energy efficiency improvements.

These activities are likely to require a substantial step change in demand, renewable generation and energy storage. Western Power are working with Energy Policy WA and other government stakeholders to develop a grid vision for the network to accommodate future decarbonisation needs.

Over the longer term, these activities will likely drive a substantial step change in demand, renewable generation and energy storage, requiring the transmission system to be adaptable and resilient to accommodate growing, and more variable demand, while maintaining a secure and reliable system.

Western Power is participating in the decarbonisation of communities and working with Energy Policy WA and other stakeholders to develop a grid vision to ensure an orderly transition away from fossil fuels. This includes supporting broader decarbonisation by enhancing our technical solutions, products and infrastructure to ensure grid security and reliability while facilitating further uptake and equitable access to renewable energy resources. Future TSPs will reflect this changing dynamic in the way the transmission network is planned and developed.

Key Findings

- **Increasing demand uncertainty**. A combination of consumer behaviour, policy, weather and technology changes means demand uncertainty is increasing markedly. Some of the key drivers of the increase in demand uncertainty are:
  - global warming
  - decarbonisation of industry
  - potential developments in the energy industry such as hydrogen production
  - distributed Photo-voltaic (PV)
  - Behind-The-Meter (BTM) batteries
  - increased Electric Vehicle (EV) usage.

  High variability in annual demand forecasts, present increasing challenges in planning for the transmission network and optimising timing triggers for new investment.
- **Increasing generation uncertainty.** A combination of market reform, expanding levels of intermittent generation technology and retirements of coal fired power stations is increasing uncertainty in the generation assumptions used to plan the network.
- **System peak demand is forecast to increase at an average annual rate of ~1.5 per cent over the next decade, based on Western Power's 2020 PoE10% demand forecasts (covering the period 2020/21 to 2029/30).** Although the growth in system peak demand is relatively low, compared to recent historical levels, areas including the Goldfields (East Region), Picton South and Kemerton-Marriott Road (South Region) and the Mandurah-Peel area (Metro South Region) remain constrained during peak demand

4 https://www.industry.gov.au/news/australia-submits-new-emissions-target-to-unfccc

conditions. Western Power has several projects progressing to alleviate these constraints and provide flexibility to facilitate higher utilisation levels. On a substation basis, the increases in peak demand us expected to result in 21 substation capacity issues requiring addressing over the period.

- **High growth in new DPV connections is driving lower SWIS system minimum demands.** With more than 2,000 MW of DPV capacity connected on the SWIS, managing power system security and reliability during periods of low operational demand is becoming increasingly challenging, particularly in relation to voltage management and system stability. Collectively, 'System Low' issues present the highest risks for planning and operating the transmission network over the short- to medium-term horizon.
- **The 330 kV network continues to be under-utilised.** Although partially driven by the highly meshed 132 kV networks, the utilisation of the 330 kV network is generally low. The additional capacity that exists on the 330 kV network presents a significant opportunity to connect new large loads and large-scale generation, particularly as industry transitions away from fossil fuels and further synchronous generation is retired (e.g., Muja and Collie).

2 About Western Power

2.1 Our network

Western Power builds, operates and maintains the SWIS transmission and distribution network. The network services an area of 255, 064km^2; it incorporates more than 1.5 GW of rooftop solar (installed at about 30 per cent of homes within the SWIS) and supplies approximately 1.2 million connected customers.

Figure 1: Overview of Western Power's Network[5]

[5] As per 20th July 2022.

The Western Power Network is unusual for two reasons: its geographical size and overall low density of connections; and its isolation and lack of interconnections to any other large systems. These attributes make the network uniquely challenging for both operation and maintenance.

The network is inherently dynamic and complex, with changing customer needs and expectations. Western Power aims to be agile and responsive to these factors while maintaining a safe, reliable and efficient electricity supply, to ultimately deliver an affordable and quality product for all Western Australians.

Figure 2 illustrates a simplified view of the bulk transmission network, including the grouping of six regions that share similar load characteristics and experience shared network issues.

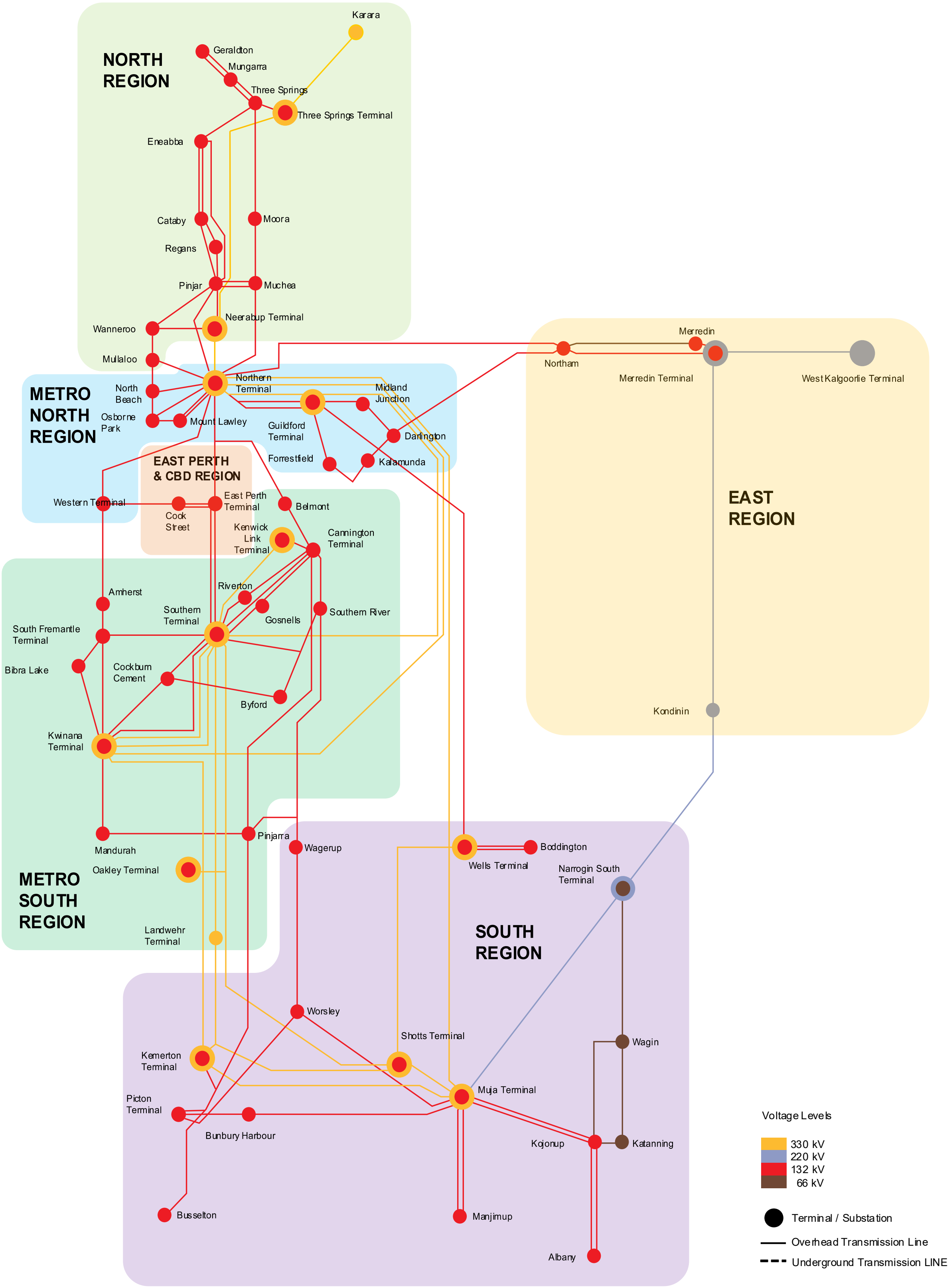

Figure 2: Simplified SWIS bulk transmission network diagram

3 Role of the Transmission System Plan

3.1 Role of the Transmission System Plan

Under section 4.5B of the WEM Rules, Western Power is required to develop a TSP that must:

(a) establish a plan for the efficient development of the transmission system for a planning horizon of at least 10 years;

(b) meet the Power System Security and Power System Reliability requirements; and

(c) be in the long-term interests of consumers.[6]

The WEM rules require Western Power to include a number of considerations in the TSP:

(a) a summary of any significant costs to the WEM that have arisen, or may potentially arise, due to the condition of the transmission network, including:

i. binding Network Constraints, and the estimated market costs of those binding Network Constraints; and

ii. the frequency and magnitude of Constrained On Quantities and Constrained Off Quantities, including for Facilities subject to Network Constraints;

(b) a set of investment options for developing the transmission system over the relevant planning horizon, which must consider network and non-network solutions to address the matters identified under clause 4.5B.4(a);

(c) analysis of market related data and an assessment of the costs and benefits, including to the WEM, of the identified investment options;

(d) a recommended development path for the transmission system that would maximise net benefits and seek to minimise the long-term costs of electricity supplied to consumers; and

(e) a high-level assessment of how the recommended development path referred to in clause 4.5B.4(d) will meet the long-term interests of consumers.

This inaugural TSP addresses the above considerations by outlining:

- key strategies that influence and drive the development of the TSP.
- planning methodology and assumptions used to prepare the TSP.
- existing and emerging network constraints relating to power system security, reliability, technical requirements, and asset condition for the most efficient and likely generation scenario across the study period.
- a set of network and non-network options to address the identified existing and emerging network constraints across the study period.
- a proxy estimate of the market impacts of network congestion calculated by analysing the hypothetical costs of Generator Interim Access (GIA) constraints.
- the current and future year expected maximum and minimum fault levels

[6] Clause 4.5B.3 of the WEM Rules

To the extent practicable, future TSPs will set out more comprehensive analysis and information on:

- Binding network constraints and their estimated market costs – upon commencement of security-constrained economic dispatch in the new WEM, Australian Energy Market Operator (AEMO) will publish a constraints library including binding network constraints. AEMO will also publish a congestion information resource, the objective of which is to provide information on patterns and market impacts of network congestion[7]. Western Power will directly employ this information in its planning activities, including in the development of the TSP. The costs of network congestion will be assessed against the cost of network augmentation to help determine the optimal point at which network augmentation will become more economically efficient than the costs of constraining generators to relieve network constraints in the market.
- A range of facility dispatch scenarios or credible dispatch patterns – the inaugural TSP based simulation studies and resulting network performance levels on an 'efficient and likely[8] dispatch at peak and minimum demand operating conditions. Future versions of the TSP will build capability to cover a range of likely dispatch patterns.
- Assessment of the development path for the TSP to maximise the long-term interests of consumers.

As part of the development of the TSP, Western Power is required to consult with AEMO and Energy Policy WA (EPWA) on:

- forecasted demand growth or reduction scenarios, including from the long-term Projected Assessment of System Adequacy (PASA)[9] and Whole of System Plan (WOSP)[10];
- scheduled connection of new loads or generators;
- expected network modifications, augmentations or retirement of existing facilities or network assets that impact costs in the WEM;
- credible contingency events and other commonly occurring credible contingencies that may significantly impact the SWIS;
- a range of facility dispatch scenarios or credible dispatch patterns;
- data, modelling and results from the testing of scenarios in the WOSP, to the extent they are relevant as inputs to the TSP;
- relevant information from the short-term PASA, medium-term PASA and long-term PASA studies conducted by AEMO under the WEM Rules;
- other market information that the Network Operator, AEMO or the Coordinator considers relevant to meeting the requirements for developing the TSP, covered in this section 4.5B.

In developing the inaugural TSP, Western Power conducted workshops with AEMO and EPWA on the TSPs scope and key modelling assumptions. As Western Power consolidates its planning activities to inform future TSPs, stakeholder engagement on assumptions, inputs and scenarios will take place earlier in the process to enable further alignment between planning inputs such as demand forecasts, generation dispatch scenarios/patterns, credible contingency events, and market costs and impacts.

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7 Sections 2.27A and 2.27B of the WEM Rules.

8 An 'efficient and likely dispatch' scenario is a security constrained and economic dispatch based on merit order under system normal conditions that would produce the lowest cost to the system.

9 The Long-Term Projected Assessment of System Adequacy is an annual study required by the WEM Rules to be undertaken by the AEMO to determine, amongst other things, the amount of generation capacity needed in the SWIS to meet the forecast peak demand plus a margin.

10 The WOSP is required by the WEM Rules to be published by the Coordinator of Energy at least once every five years setting out a plan for the efficient development of the SWIS to meet power system needs, assisting in the transition to a lower-emissions system, identifying requirements for network investment and informing industry and policy makers regarding opportunities and future needs of the SWIS.

3.2 TSP Target Audience

The TSP provides stakeholders and customers with important information about the existing and future state of the transmission network in the SWIS. It is predominantly aimed at existing and prospective transmission customers who may be seeking to connect large-scale load, generation, and storage solutions to the transmission system.

The TSP is intended to provide information on performance levels, emerging constraints, and opportunities in the transmission network to help guide investors on the optimal timing and placement of their proposed connection plans to enable meeting electricity demand and continue delivering valued service to consumers.

3.3 Interaction between the TSP and WOSP

The inaugural version of the WOSP was developed and delivered by the Energy Transformation Taskforce in August 2020[11]. The WOSP sets out a 20-year forward outlook for the sector, informed by engagement with industry stakeholders. Along with AEMO, Western Power was a key contributor to the plan.

The inaugural WOSP was a detailed study of how the SWIS may evolve in the next 20 years. Using data provided by industry, the plan modelled four energy scenarios to show how changes in demand, technology and the economy may shape electricity use and guide investments in large-scale generation, storage and network solutions to achieve lowest-cost electricity. The study aggregated the SWIS into 11 transmission zones (or nodes) to test the four energy scenarios, modelling the impact on emissions under each scenario.

Both the WOSP and TSP play a key role in planning for the transmission system over the short, medium and long-term. While the two plans share many key inputs and assumptions, they also have important differences, including but not limited to:

- Timescales – the TSP is focussed on presenting network performance and opportunities within a 10-year timeframe, whereas the WOSP provides a summary of four energy scenarios over a 20-year outlook. This is because the TSP outlines efficient investment opportunities for the transmission system and a 10-year outlook is realistic and reasonable for planning purposes.
- Scenarios considered – the TSP presents network performance, opportunities and network development using a security constrained and economic dispatch based on merit order across a range of demand levels. The WOSP covers a broader range of energy scenarios to better understand the uncertainty of how changes in demand, technology and the economy may shape electricity use and guide investments to achieve lowest-cost electricity.
- Identification of network constraints – major transmission inter-nodal constraints and augmentation are developed in the WOSP. The TSP will:
  - complement the WOSP analysis, while fine-tuning required augmentation technical details, costs and binding constraint timelines
  - identify intra-nodal constraints and customer load/generation growth requiring network augmentation
  - optimise major network asset replacement works.

The WOSP includes provisions for identifying a proposed network augmentation as being of 'Priority Project' status when it demonstrates major benefits in addressing network constraints across multiple

[11] Available on EPWA's website: https://www.wa.gov.au/system/files/2020-11/Whole%20of%20System%20Plan_Report.pdf

energy scenarios. Once a proposed network augmentation is given a Priority Project status and would potentially deliver benefits within a 10-year timescale, it is further developed and refined in the TSP.

Future TSPs will develop import and export boundaries that also align with the complete set of inter-nodal import and export boundaries presented in the WOSP. This will ensure better consistency in outputs when planning for the transmission system.

3.4 Interaction between the TSP and NOM

The Network Opportunity Map (NOM) is a regulatory requirement for Western Power outlined in chapter 6A of the Access Code[12], published together annually with the TSP on an annual basis on 1 October.

The primary purpose of the NOM is to present network opportunities on both the distribution and transmission system within a 5-year time horizon, with opportunities on the transmission system limited to network constraints at the zone substation level.

A network opportunity is the presentation of opportunities to providers of potential alternative options (all customers, industry and market participants) to address transmission and distribution system constraints by providing options alternative to network augmentation.

This year’s network opportunities focus on alleviating thermal and voltage capacity constraints. Future versions will include a broader scope of opportunities as Western Power increases its knowledge and understanding in this area. In addition, Western Power has decided to present a broader array of network opportunities on the transmission system beyond zone substation constraints, to promote transparency and to signal potential network opportunities as early as possible to assist in planning within the 10-year TSP timescale[13].

For further detail on network opportunities, how they are developed and the process to submit an alternative option, refer to the NOM 2022[14].

3.5 Interaction with latest Government Policy announcements

3.5.1 Coal-fired generation retirements

In June 2022, the State Government announced the staged retirement of the Muja and Collie coal-fired power stations by 2030[15], as the continued uptake of rooftop solar and renewables has forced changes in the energy system to ensure a secure electricity supply and guard against higher power bills.

In addition to the previously announced closure of Muja C’s G5 and G6 units by 2024, the Collie Power Station will close in late 2027, followed by the Muja D units in late 2029.

To ensure continued supply stability and affordability, the State Government has committed to an estimated $3.8 billion in new green power infrastructure investments in the SWIS, including wind generation and storage.

Western Power will work together with AEMO and other key stakeholders to ensure alignment on modelling assumptions, inputs and scenarios used to determine the impact of these changes to the

12 https://www.wa.gov.au/sites/default/files/2019-08/ElecNetworksAccessCode.pdf
13 Where Western Power decides to procure a service in response to a network opportunity, the Non Co-optimised Essential System Services framework as outlined in sections 3.11A and 3.11B will apply.
14 https://www.westernpower.com.au/suppliers/tenders-and-registrations-of-interest/network-opportunity-map/
15 https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/06/State-owned-coal-power-stations-to-be-retired-by-2030.aspx

transmission system. Due to the timing of the announcement relative to Western Power's annual planning cycle, the impact of this announcement will be included in the TSP 2023.

3.5.2 SWIS Demand Assessment

In August 2022, the State Government announced a fast-tracked assessment of new and existing demand for renewable energy to help inform the future demand for low-emissions electricity supply on the SWIS, as a growing number of industries and businesses seek to decarbonise through electrification. This assessment will be an essential tool in achieving a smooth and orderly transition towards net zero by 2050 [16].

A Treasury-led taskforce has been created with a number of key industry stakeholders, including Western Power, to perform an interim assessment ahead of the next WOSP, which is required by 2025. Relevant outputs from the demand assessment will be included in the TSP 2023.

[16] https://www.mediastatements.wa.gov.au/Pages/McGowan/2022/08/Assessment-of-electricity-demand-to-inform-WA%E2%80%99s-future-network.aspx

4 Modelling Assumptions

4.1 Key Input Data and Assumptions

Key input data and assumptions taken into consideration when developing the TSP include:

- WEM Technical Standards clause 2.8.14;
- Power system security and reliability standards and requirements – section 3 under the WEM Rules and section 2 under the Technical Rules;
- Any Priority Project identified in the WOSP or major augmentation that Western Power is able to progress in accordance with the Access Code. Note: No Priority Project has been identified under the 2020 WOSP;
- Quality and reliability standards under part 2 of the Network Quality and Reliability of Supply Code 2005;
- Any government policy specified in the WOSP that the Coordinator considers may impact on the development of the TSP, as may be advised by the Coordinator pursuant to the consultation process referred to in clause 4.5B.6 or specified in the WOSP published by the Coordinator under section 4.5A.
  - As discussed in section 3.5, the State Government has recently announced the retirement of the Muja and Collie coal-fired power stations by 2030, as well as a fast-tracked assessment of new and existing demand for renewable energy to inform the transition to decarbonisation. Due to the timing of the announcements relative to Western Power's annual planning cycle, the impact of these announcements will be included in the TSP 2023.

4.2 Modelling parameters

- DigSILENT Powerfactory used to perform system simulation studies.
- The study period is defined as the period 2020/21 to 2029/30.
- Key network strategies, planning standards and guidelines were taken into consideration in developing the TSP, including but not limited to network Region Strategies, 66 kV Rationalisation Strategy, Transmission Planning Guidelines and Asset Management strategies.
- Replacement of major transmission assets (i.e., power transformers and switchboards) are considered in creating long-term network development plans, as these assets are characterised as bulky, expensive and with long lead times, presenting opportunities to optimise replacement plans with other network investment drivers.
- System simulations are performed using Western Power's maximum and minimum demand forecasts covering the period 2020/21 t0 2029/30:
  - PoE10% system maximum and PoE50% system minimum demand forecasts for modelling peak and minimum demand conditions, respectively.
  - PoE10% and PoE50% substation non-coincidental maximum demand forecasts for modelling peak demand conditions
- Simulation studies to assess network security and reliability constraints are based on the 2020/21 demand forecasts. Refer to Appendix B: System Study Modelling Data for more detail.
- Generation dispatch profiles for peak and minimum demand conditions are developed using a security constrained and economic dispatch based on merit order that includes operational advice provided by AEMO. Refer to Appendix B: System Study Modelling Data for more detail.

- The generation fleet used to perform system simulations considers the current generation fleet and new generation connections that have become committed. It also includes the recent retirement of the Kwinana Cogeneration Plant (December 2021) and the scheduled retirements of Muja 'C' G5 and G6 units in October 2022 and 2024, respectively. The Kalamunda synchronous generation retirement in July 2022 will be considered in the next TSP.
- The thermal transfer boundaries presented within each of the Region chapters (sections 10 to 15) are indicative in nature. The boundary capacities and their expected power flows are sensitive to the demand forecast and generation dispatch assumptions used. They should only be used to provide a guide for existing or new users prior to lodging a connection application, where more detailed connection studies will be performed to accurately assess the impact of a proposed connection.
- The following definitions have been applied to the status of each project:
  - Completed – project completed within the period 1 July 2020 to 30 June 2022
  - Committed – project committed within the period 1 July 2020 to 30 June 2022
  - Proposed – proposals or projects that are expected to be developed and delivered within the study period (i.e., by 2029/30).
- Modelling only includes completed and committed projects. All proposed projects will be taken into consideration once they reach a committed status. Uncommitted customer connections are not presented in the TSP as they are still speculative in nature and their inclusion may misrepresent network performance levels and likely network development pathway.
- A building block estimate tool is used to develop cost estimates where more detailed cost estimates are not available.

5 Planning Methodology

5.1 Overview

As a Network Service Provider (NSP) it is Western Power's role to provide power transmission and distribution services to generators and load customers within the South West Interconnected Network (SWIN). In providing these services Western Power operates the existing network and undertakes planning activities to ensure that new generator connections can be accommodated, with new and growing existing loads supplied according to established standards.

5.2 Annual Planning Cycle

The Annual Planning Cycle (APC) includes all the activities required to produce or update the 10-year Network Plan. The Network Plan includes all the network-related expenditure proposed over a 10-year period to meet a range of objectives and regulatory obligations, while maintaining an acceptable level of risk and performance for customers. It commences with the acquisition of latest telemetry and metering data, and culminates in a (constrained) list of risks and constraints that require addressing within the 10-year time horizon and publication of the TSP. The process takes approximately 12 months to complete with ad-hoc updates for any significant departures from anticipated results.

The Network Plan is usually finalised in the second quarter of a calendar year and provides a baseline for all network related expenditure across a 10-year outlook. It includes all approved and nominated projects, as well as candidates to address various risks and constraints in the network.

The delivery of the TSP is a key component of the APC.

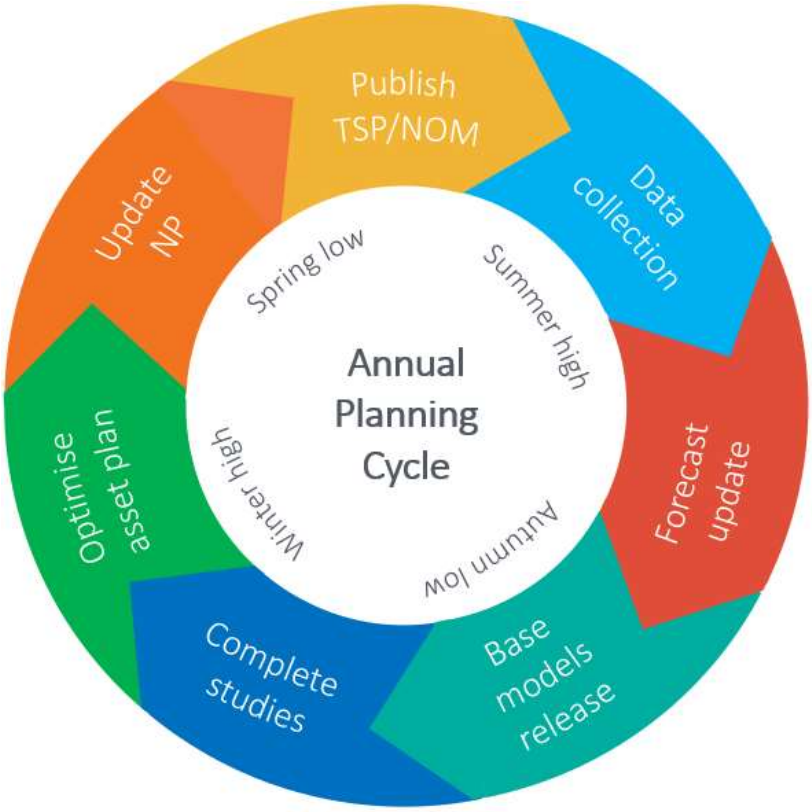

Table 1: Annual planning review and reporting cycle

5.3 Network Planning Process

The Network Plan considers all relevant network strategies and follows a planning process to convert an unconstrained case (reference case) to a constrained case following prioritisation and further optimisation.

Figure 3: High level end to end planning process

The end-to-end network planning process has five key steps as outlined in Figure 3, which is broadly the same for all types of network expenditures with some differences in the method of prioritisation and optimisation based on the level of risk. This includes the evaluation of non-network solutions and application of new or emerging technologies.

5.3.1 Step 1 – Identify the Issues

Western Power routinely assesses the condition of the transmission network and its ability to supply existing and future demand against a range of requirements and obligations including the Technical Rules[17], WEM Rules[18], Network Quality and Reliability of Supply Code (NQRS)[19], Access Code and asset management requirements and objectives.

Our Network Performance Framework, outlined in Figure 4 details the key parameters used to undertake transmission network performance management. Key inputs to these assessments include:

- changes in forecast load and demand
- introduction of new loads or generation sources
- change in asset condition
- past reliability, safety or other network performance characteristics.

This step generates a list of network or asset issues that need to be further examined and addressed.

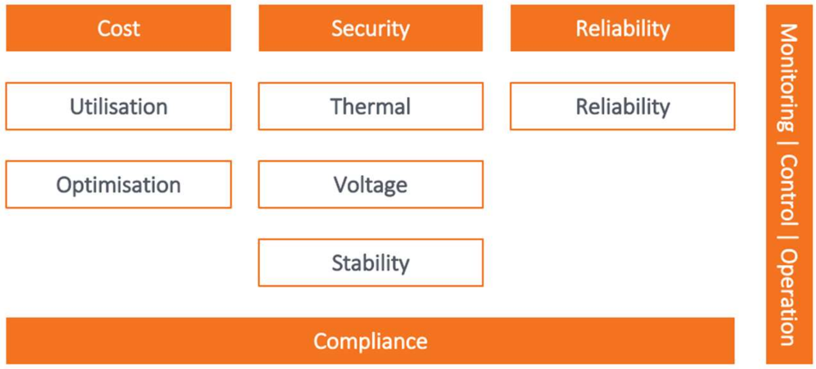

Figure 4: Network Performance Framework

[17] Approved Technical Rules - Economic Regulation Authority Western Australia (erawa.com.au)

[18] https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-rules

[19] https://www.wa.gov.au/organisation/energy-policy-wa/regulatory-framework

5.3.2 Step 2 – Option Analysis

This step develops a series of options or solutions to address the emerging limitations in the network and asset classes. This includes analysis of trade-offs between operational and capital expenditure, asset replacement and maintenance solutions and initial assessment of alternative options to traditional network solutions.

In planning to meet peak demand levels, system studies are performed using a one-in-ten-year peak demand forecast and substation peak demand forecasts. This ensures worst-case bulk transmission limitations and worst-case localised overloads are identified. In planning for minimum demand levels, Western Power uses a one-in-two-year demand forecast. For both sets of demand conditions, the strategic direction needs to be considered along with long-term network plans, corporate performance measures such as reliability and safety, operational experience and asset condition, to identify issues that are present on the network and deliver better and more efficient long-term outcomes.

Several generation scenarios are modelled into the probabilistic assessment of generation and load development options across a 10-year period, comprising the five-year access arrangement period and several years post the regulatory period to assess the performance of the transmission network. However, the TSP only presents network information based on a security constrained and economic dispatch based on merit order to identify constraints and establish network development plans.

Contingency analysis is then undertaken with the credible contingencies based on the TR and Planning Guidelines. All the credible contingencies are considered for any single contingency (N-1), a single contingency and outage (N-1-1) and a double contingency (N-2) analysis (Perth CBD).

The outcome of this analysis high level options that will be developed based largely on network solutions, but also include the possibility of various alternative options and non-network solutions. Western Power uses discounted cash flow techniques to assess the feasibility of all options and make recommendations.

To estimate cost, Western Power uses a blend of historical average unit rates, estimations and capital project building blocks based on previous projects and/or benchmarking. Specific project estimates are developed where there are unique project components, or a benchmark does not exist.

The output of this 'bottom up' approach is an unconstrained (funding) case that includes all the projects with respect to the network and asset needs.

5.3.3 Step 3 – Optimisation

The optimisation process includes actions such as:

- identification of network need and opportunities (reference scenario)
- outputs from condition assessments
- verification of the lowest-cost option
- completion of risk reduction benefit assessments
- incorporation of the corporate strategy and plans for the network, including where higher capacity assets are needed in the long term, or taking into account utilisation and decommissioning of assets.

Where overlaps of drivers or dependencies with other projects exist on targeted assets, consideration is given as to how to optimise the solutions across projects.

Optimisation with asset condition drivers in transmission is typically restricted to large assets such as power transformers, indoor switchboards and transmission lines. These assets are characterised as bulky, expensive and with long lead times, presenting opportunities to optimise replacement plans with other network investment drivers.

5.3.4 Step 4 – Prioritisation

The prioritisation process considers cross-portfolio assessment and applies a weighted average scoring methodology when assessing a variety of options in both the short and medium term.

The selection of growth, asset condition and reliability investments for each year is based on a series of criteria covered in Step 1 – Identify the Issues. These investments are prioritised through a multi-criteria assessment which provides an overall business value of the proposed investment in the network.

Assets within a particular group are prioritised and optimised in line with the relevant asset strategy, with the volume set by delivery constraints or the number of assets that can be addressed within the next 10 years. At an investment level these are prioritised by considering factors such as customers at risk, likelihood of failure, asset condition and criticality[20].

Some level of further optimisation is done at this stage with respect to the timing of works.

At the completion of this process, each portfolio is prioritised to satisfy any delivery or funding constraints (the constrained case).

Steps 1 to 4 demonstrate that Western Power's network development plans are based on the least cost sustainable options, optimised across multiple network drivers and delivery.

5.3.5 Step 5 – Forecasting the Future Performance:

Following the end-to-end process, Western Power forecasts the performance of the network based on the proposed projects against measures such as Service Standard Benchmarks, anticipated safety performance, and movements in risk indices.

[20] Criticality, with respect to the network, is considered only for transformers, switchboards and lines, which might take longer period to be replaced or brought back to service and supply a large number of customers.

6 Energy and Demand Forecasts

6.1 Demand Forecasting Methodology

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

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

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

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

The accuracy of past forecasts is monitored, and any significant departures analysed for possible causes of inaccuracy. Adjustments are then made in the design of new forecast models, or the type and quality of data used. All input data is assessed for credibility and relevance before being approved for inclusion in the forecasting processes. Western Power measures and aggregates electricity demand averages based on five-minute intervals for the purposes of electricity demand forecasting.

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

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

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

6.2 Customer Connections, Solar DPV and Energy Forecasts

The method used to produce energy export forecasts from the network is based on three trends: customer connection numbers, adoption of solar DPVs, and energy imports from solar DPVs. This allows the model to reliably incorporate the effect of socio-economic and technological factors that result in highly dynamic and evolving energy consumption patterns.

- **Customer Connections Forecast –** includes economic forecasts, such as gross regional product, gross regional demand and regional population to model estimated monthly connection numbers. The number of connections comprises counts of metered connections with a National Metering Identifier (NMI) and unmetered connections such as streetlights and bus stops.
- **Solar DPV Capacity Forecast** - reliable long-term solar DPV installation forecasting is important for developing accurate forecasts for electricity consumption and demand. Although the mass adoption of

solar DPV is a relatively recent phenomenon, the rate of adoption has had a material demand-reducing impact.

- **Energy Forecasts** - produces separate forecasts for exported energy from the grid and imported energy from solar PV panels. The model produces monthly forecasts at hierarchy levels comprising tariff type, customer segment and substation levels. It also reconciles forecasts at different hierarchy levels.

6.3 Difference between energy scenarios and demand forecasts

Energy scenarios, unlike demand forecasts, look at historical data and certain assumptions of the future (to simulate scenarios such as climate change or high electric vehicle uptake. Demand forecasts make assumptions about what may happen in the future based on external forecasts on economic factors (BIS Oxford), population (WA Tomorrow) and forecasts using historical data relating to connection numbers, PV capacity, and imported and exported energy. The TSP uses demand forecasts rather than energy scenarios to present the most likely network development pathway.

Energy scenarios are similar to demand forecasts but are created with a specific future scenario in mind. Energy scenarios allow Western Power to better understand the range of sensitivities that may eventuate and allow the organisation to mitigate the risks of such scenarios by planning the future of the network accordingly.

6.4 Difference between WP and AEMO forecasts

AEMO produces annual demand forecasts as part of the Electricity Statement of Opportunities (ESOO) for the WEM for the purposes of assessing the adequacy of the power system to meet peak demand across a 10-year planning horizon. Although the inputs and methodologies that drive the development of Western Power and AEMO’s 10-year demand forecasts are comparable they differ, resulting in different forecast outputs. Some of the key differences include:

- Western Power produces forecasts based on an ‘as generated’ basis, which includes gross generation for all market registered and unregistered generation facilities in the SWIS. AEMO demand forecasts do not include unregistered generation and auxiliary loads.
- Western Power demand forecasts are provided for a ten-year outlook compared to AEMO’s five-year outlook.
- Western Power utilises five-minute intervals for aggregation of demand versus AEMO's 30-minute interval aggregation.
- Western Power utilises both calendar year and financial year in forecast reporting, while AEMO uses the capacity year, which begins in October.

As Western Power consolidates its planning activities to inform future TSPs, stakeholder engagement on assumptions, inputs and scenarios will take place earlier in the process enabling further alignment demand forecasts.

6.5 Demand Forecasts

Western Power’s forecasting reflects the challenges and opportunities the industry is facing, fuelled by the development of alternatives to electricity supplied by the network and in mass-market consumer technologies.

Demand forecasts are reviewed periodically to track changes in generation and demand and reveal network risks and development opportunities. The forecasts are based on both historical trends and key underlying factors such as weather, population growth, economic cycles, changing consumer behaviour and tariffs, and future technological advances.

Several forecasts are developed covering a 10-year period, comprising the five-year access arrangement period and several years post the regulatory period to assess the performance of the transmission and distribution networks. These include:

- Transmission network assessments – coincidental system PoE 10% peak demand and system PoE 50% system minimum demand forecasts used to model peak and minimum demand scenarios.
- Substation capacity assessments – non-coincidental system PoE 10% peak demand forecasts.

6.6 Forecast Performance

6.6.1 Maximum Demand

Annual maximum demand on the network has been relatively variable since 2010, peaking above 3,900 MW in all years except two, though the 2020 and 2021 summer maximum forecast chart demonstrates the potential increased volatility in annual peaks (represented by the forecast band).

The 2022 summer maximum demand of 4,223 MW occurred on 19 January 2022 at about 18:00– the second-highest annual maximum demand since 2010.

Maximum demand was 179 MW (4,223 – 4,044 MW) i.e., 4 per cent higher than in 2021, which was driven primarily by a run of consecutive days with temperatures surpassing 38°C and overnight temperatures in some cases exceeding 33°C.

Perth recorded its hottest summer in recorded history in 2022, which resulted in extremes that were observed in operational maximum demand, as well as a higher average demand over the 2021-22 summer.

BTM DPV continues to push maximum demand later in the day, from between 17:30-18:30 and 18:00-19:00, closer to sunset when the impact of solar generation is minimal.

Figure 5 demonstrates that at a system level, the forecast from 2020 performed well, capturing the peak events from summer 2021 within the bounds of the PoE10 forecast. The outlook for the remainder of the forecast period is for the maximum demand trend to be broadly similar, as previously predicted, but with the PoE10 trendline slightly lower and the PoE90 trendline marginally higher.

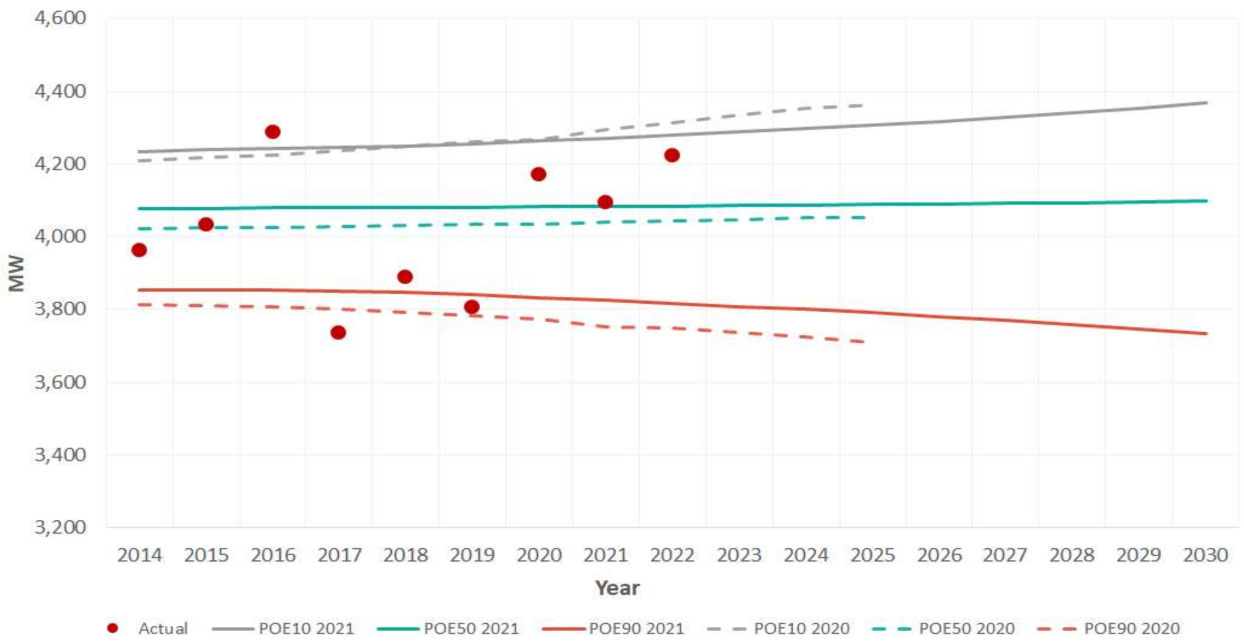

Figure 5: Historical and forecast system maximum demand - 2020 and 2021

6.6.2 Substation Performance

The system maximum demand forecasts were able to predict the peak events from the summer of 2021/2022 well, but conditions are more variable by locality. The following subset of substations provides a detailed look at performance by area. These substations have been selected as they are forecast to exceed their substation capacity within the next 10 years.

Byford

The actual maximum peak value in 2022 (summer) lay between the PoE50 and PoE10 forecast from 2020, reaching 81.1 MW, on-par with the PoE10 forecast. The 2021 prediction shows a more pronounced slope than previously forecast.

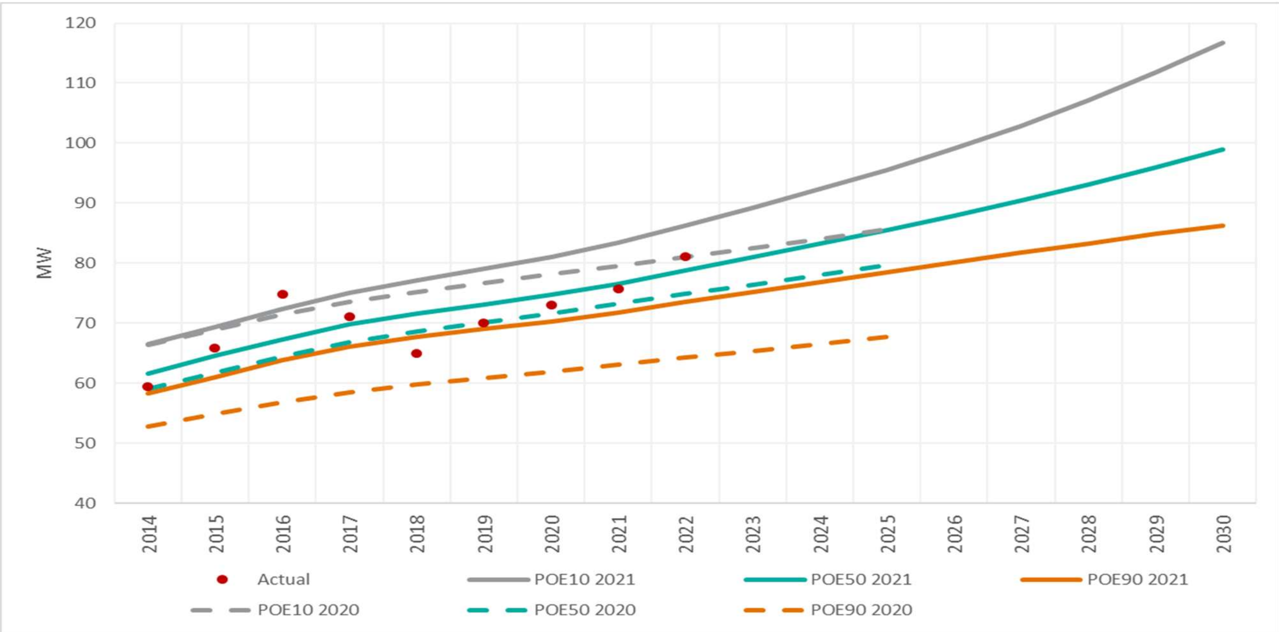

Figure 6: Byford non-coincidental historical and forecast maximum demand

Capel

This forecast performed well over time over both sets of forecasts. The actual maximum peak value in 2022 (summer) lay between the PoE50 and PoE10 forecast from 2020, reaching a peak value of 22.1 MW.

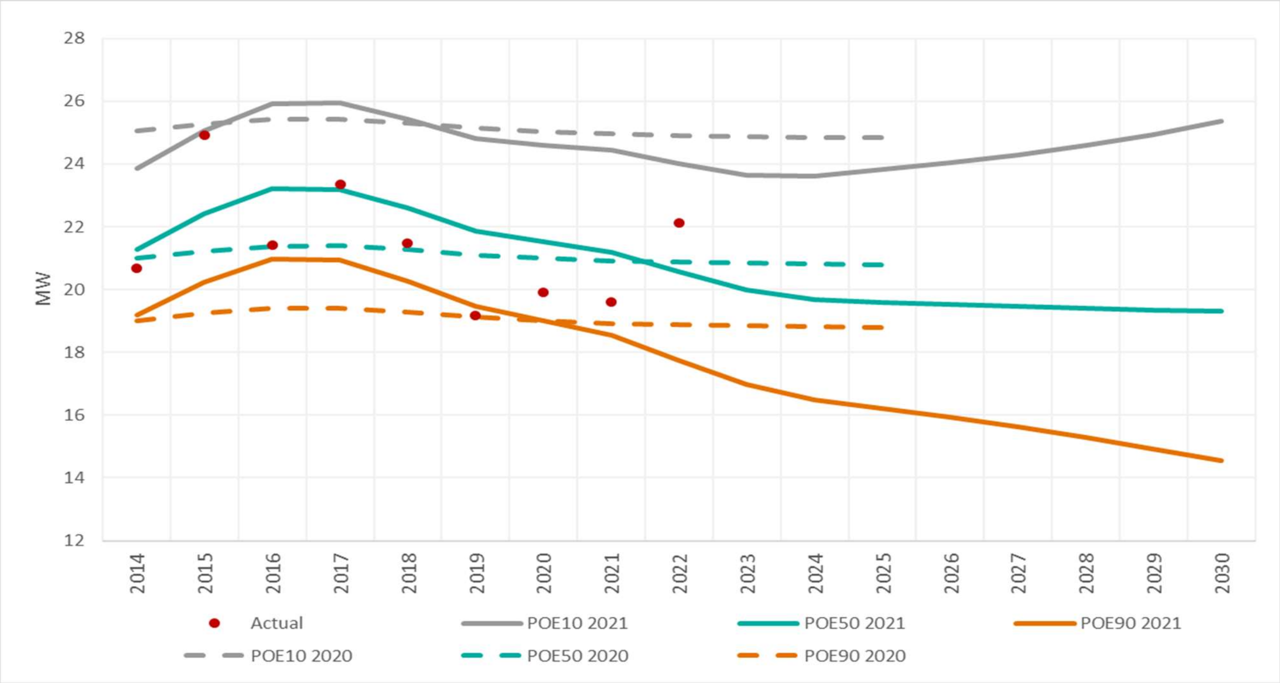

Figure 7: Capel non-coincidental historical and forecast maximum demand

Clarkson

The actual maximum peak value exceeded the PoE10 forecast from 2020 by 14 per cent during the summer of 2022, reaching 71.5 MW. The 2021 forecast considers the growth in the northern corridor and the recent extreme weather conditions, resulting in a steeper upward trend over the remainder of the forecast period than previously predicted.

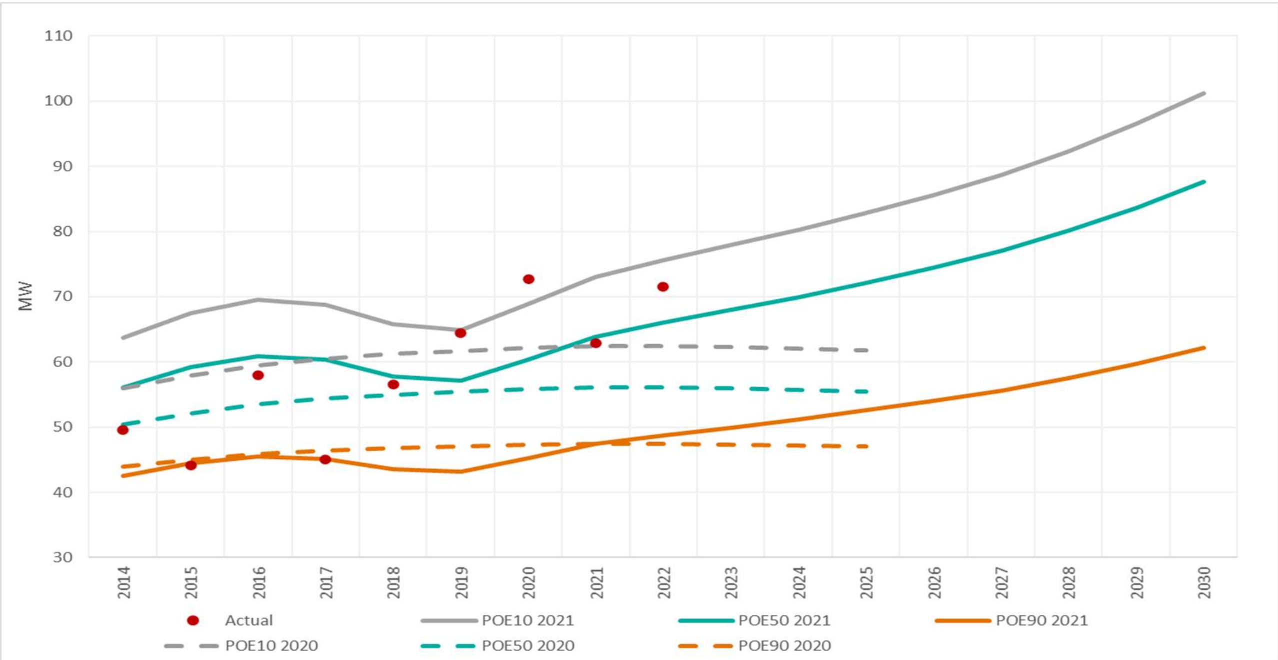

Figure 8: Clarkson non-coincidental historical and forecast maximum demand

Southern River

This forecast performed well over time, but the summer 2022 maximum demand exceeded the forecast from 2020 by 7 per cent, reaching 86.4 MW compared to the predicted 81 MW. The forecast trend from 2021/22 indicated sharper growth than previously predicted, indicating expansion of development of the locality.

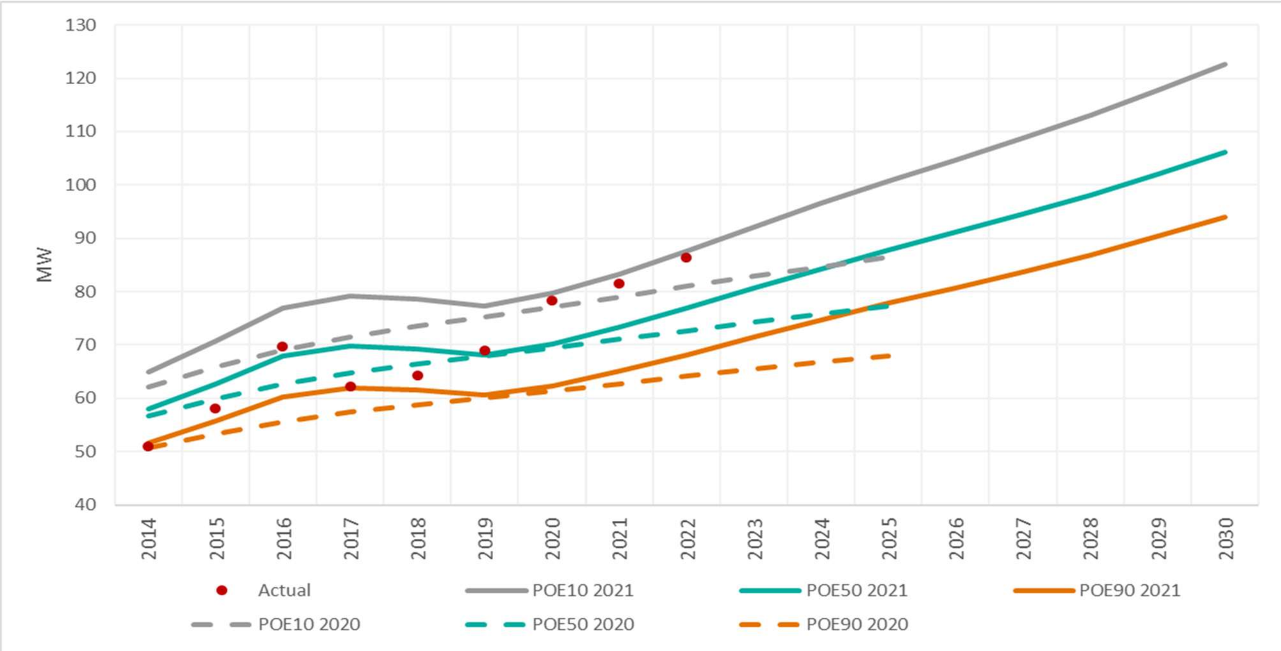

Figure 9: Southern River non-coincidental historical and forecast maximum demand

Yanchep

Yanchep is another area experiencing high growth, where the forecast has performed well. The maximum demand from summer 2022 was under the 2020 forecast PoE10 by around three per cent, reaching 57.9 MW. The 2021 PoE10 forecast is expected to follow a similar trajectory as the 2020 forecast.

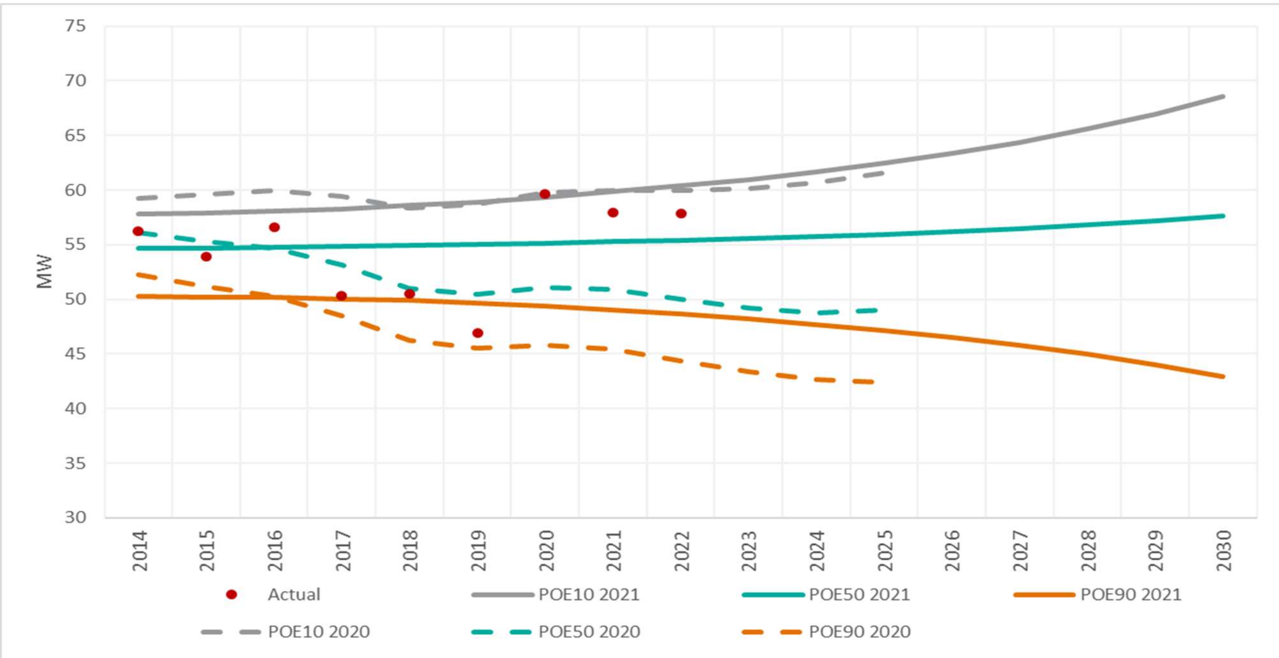

Figure 10: Yanchep non-coincidental historical and forecast maximum demand

6.6.3 Minimum Demand

Annual minimum demand on the network has consistently decreased and is forecast to continue decreasing. Increasing residential solar DPV is driving this decrease, with the lowest minimum loads typically seen during the middle of the day on weekends in spring and autumn. The 2020 and 2021 Daily Minimum Demand Forecast chart shows the decreasing minimum demand.

Minimum demand on the network is creating increasing challenges in the planning and operation of the SWIS, including voltage management and system stability. Western Power and AEMO are working together to understand and quantify emerging risks to power system security during periods of low demand and to ensure appropriate responses, frameworks and mechanisms are in place and available to maintain power system security when called upon.

Minimum demand events tend to occur between 11:00 and 13:00 on non-working days in spring when temperatures are mild and skies are clear. Minimum demand records continue to be driven by the strong uptake of DPV. Previously, minimum demand would have expected to have occurred overnight and in the early hours of the morning. The current minimum demand record of 865 MW[21] was set in 2021, occurring on November 14, 2021.

Minimum demand records are being broken each spring and the forecast trend is declining at a steeper rate than previously forecast. It is notable that the observed system minimum demand has not yet fallen below PoE90.

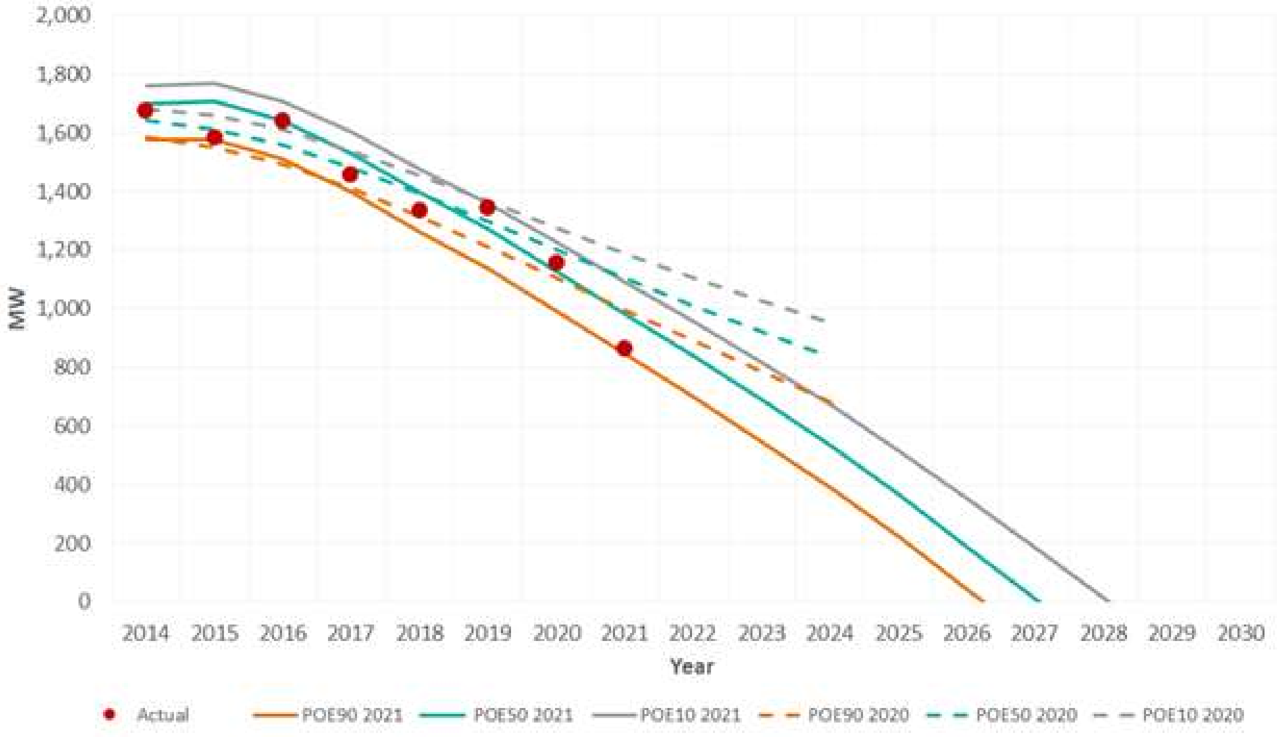

Figure 11: Historical and forecast system maximum demand - 2020 and 2021

[21] Equivalent to 761 MW, based on AEMO's demand definition – See 2022 ESSO - https://aemo.com.au/-/media/files/electricity/wem/planning_and_forecasting/esoo/2022/2022-wholesale-electricity-market-esoo.pdf?la=en

6.7 Technological Trends

The energy market is undergoing rapid change and the following technologies have been identified as having a significant impact on the evolution of the grid. The adoption and uptake of each of these technologies will have an impact on forecasting performance.

Battery storage

Western Power's PowerBanks are community batteries with the added benefit of virtual solar storage. They allow eligible households access to virtual storage in the battery to store their excess solar power. As of July 2022, there were 13 community batteries (one 105kW capacity, 11 x 116kW capacity and one BTM community battery). Battery storage will also have an impact on energy demand forecasting, and scenarios are currently under development for future inclusion in energy demand forecasting.

Electric vehicles

There were an estimated 4,200 EVs registered in Western Australia end of March 2022, an increase from 3,700 in 2021, making up 0.26 per cent of registered vehicles in Western Australia. Under AEMO's slow-growth scenario this number would increase to almost 82,000 in 2031, or over 350,000 in the expected-scenario and just over 788,000 in high-demand growth scenario[22]. EV scenarios are expected to be included in Western Power forecasting from 2022/2023, and the impact in the short-term is low but is expected to increase substantially by the end of the forecast period.

Hydrogen

The Western Australian Renewable Hydrogen Strategy sets out ambitious goals to be achieved by 2030 including hydrogen exports, gas pipelines to contain up to 10 per cent renewable hydrogen blend, and renewable hydrogen use in mining haulage vehicles and transportation in regional WA. Western Power continues to receive strong interest in hydrogen facilities, which is anticipated to support decarbonisation and result in large new loads on the SWIS towards the end of the decade.

Standalone Power Systems

Stand-alone power systems (SPS) are another major emerging technology. These off-grid systems operate independently from the main network and are provided for some rural customers. Each SPS consists of a renewable energy supply such as solar panels, battery energy storage system and a backup generator, making them completely self-sufficient power units.

With 100 SPS units currently installed and 4,000 to be installed by 2032, 330,000 km of overhead lines will be removed, power outages for customers using SPS units will be reduced by around 90 per cent and 90 per cent of each SPS unit's energy will come from DPV.

Electrification/Decarbonisation

Electrification is the shift from non-electric energy sources to electricity at its final point of consumption. It is an emerging trend that is being primarily driven by electric end-use technologies, public interest, and government policy aimed at reducing air pollution and mitigating climate change.

Electrification, depending on its extent and transition, could require a substantial and rapid response from the Western Power Grid, which would be relied on to meet the additional growth in demand for electricity.

[22] Source: Graham, P.W. and Havas, L. 2021, Electric vehicle projections 2021, CSIRO, Australia

7 Generation planning

Western Power's transmission planning responds to forecast growth in maximum demand and the expected connection of new generation[23]. Although Western Power's planning process considers a broader range of demand and generation scenarios, the inaugural TSP only presents network constraints and associated development plans for the most likely peak and minimum demand scenarios. Western Power consults with AEMO to develop a security constrained and economic dispatch based on merit order credible across a range of system demand levels.

Connection of generation to the Western Power Network occurs on an unconstrained basis. That is, the network is planned to ensure that for all credible contingencies contemplated by the Technical Rules, all generators can export energy up to their declared sent out capacities[24] regardless of what other generators are exporting. As a result, new generation seeking to connect to the Western Power Network often requires significant and costly network augmentation to facilitate its connection.

As highlighted in Section 1, the WEM is currently targeting 1 October 2023 to transition to a constrained network access framework, with generators competing for access to the network via the WEM where dispatch will be subject to network constraints. The implementation of a constrained network access framework is anticipated to provide several benefits for Western Power, AEMO, participants and consumers including:

- providing more equitable access for generators and reducing the time and cost associated with network access;
- improving efficient use of existing infrastructure;
- providing a long-term sustainable solution to replace the Generator Interim Access (GIA) solution;
- allowing better management of power system security; and
- placing downward pressure on prices.

The constrained network access model allows Western Power to facilitate the connection of new generators without requiring deep network augmentation to alleviate network congestion (which may only occur for short periods of time). The adoption of a fully constrained access regime is expected to simplify the connection process, encourage efficient network investment in the long-term and promote competition in upstream markets.

With the deferred adoption of a constrained access market, Western Power and AEMO identified an interim solution, the Generator Interim Access (GIA) solution. The GIA was designed to support new generator connections in a timely manner until constrained network access is adopted and will:

- curtail new generators (only) to maintain system security; and
- have a dispatch objective using a 'minimise-runback' approach based on contribution to a network constraint (or coefficient).

The GIA has facilitated the connection of 500 MW of generation across five sites since its inception however, as the WEM transitions to a fully constrained access market, no more generation will be connected under GIA and all market participants will operate under the constrained access model.

23 New generation entrants are considered in system studies for the TSP when they have become committed and been given an 'Network Access Application Offer'.

24 The declared sent-out capacity is the maximum amount of power that the generator has contracted with Western Power to export to the network.

8 Technical Rules compliance

Western Power is regulated in accordance with the Electricity Networks Access Code 2004 (the Code) by the Economic Regulation Authority of Western Australia (the ERA).

The Technical Rules is a document mandated under Chapter 12 of the Code, with the scope of the Technical Rules outlined in Appendix 6 of the Code. The Technical Rules outline the obligations of Western Power and connecting users regarding planning, design, operation and performance of the network and facilities and equipment connected to the network. In planning transmission network investment, Western Power aims to comply with the Technical Rules while maintaining an acceptable level of risk and performance for customers in line with the broader network development plan.

The Technical Rules commenced on 1 July 2007 with a provision that the existing network and all connected user facilities (at 1 July 2007) were deemed to comply with the Technical Rules. This deeming provision enables pre-existing parts of the network to not be required to be upgraded if they operate satisfactorily to the new standard. Any equipment amended or modified since the initial commencement of the Technical Rules must comply with the Technical Rules. However, it is recognised that over time changes in technology, customer needs and network configuration have made it difficult to comply with some of the requirements in the Technical Rules. Therefore, the Code includes provisions that allow Western Power to apply to the ERA to obtain an exemption from one or more requirements of the Technical Rules. The process for obtaining a derogation for Western Power is described in Clauses 12.40 to 12.49 of the Code. Network users can also seek an exemption from their own obligations by applying to Western Power as described in Clauses 12.33 to 12.39 of the Code.

Table 2 outlines instances where Western Power is managing risks of non-compliance on the transmission system with relevant Technical Rules requirements. It does not include derogations granted by the ERA relating to a (single) customer's facility. The purpose of presenting these is to highlight to existing and future potential users where parts of the SWIS may perform at lower levels of service than currently prescribed under the Technical Rules.[25]

These instances have been grouped in the following treatment categories:

- Exemption under consideration/approved – Western Power has formally submitted or been granted an exemption from the relevant requirements of the Technical Rules by the ERA. This may occur when the costs to achieve compliance with the Technical Rules is disproportionate to the benefits gained, or when there is uncertainty in network drivers (for example, demand forecasts) such that any proposed investment to address a non-compliance may be potentially regrettable.
- Manage non-compliance – Western Power has assessed the risk of a potential non-compliance and decided that due to the level of risk, it is more prudent to manage the risk through operational maintenance until the risk increases to a level that triggers network investment. This may occur when a Technical Rules requirement may not be achieved, but the level of non-compliance is marginal and/or the probability of the event to result in a non-compliance is very low.
- Proposed investment – Western Power has proposed investment to address non-compliances. In some instances, a temporary non-compliance may exist for the period prior to the completion of the works to address the non-compliance. Western Power continues to manage the risk associated with the non-compliance until the completion of works.

On 30 July 2021, Western Power made a submission to the ERA outlining proposed amendments to the Technical Rules to update requirements and standards in response to the State Government's energy

[25] Only non-compliance instances that are considered significant in nature to the transmission system and relate to power system security and reliability have been included in Table 1.

transformation process[26]. When approved, the proposed amendments will better address emerging customer and network needs, reduce the need for exemptions and make the network planning process more flexible and efficient.

Table 2: List of existing non-compliance with the Technical Rules

Theme	TR Clause	Description	Treatment	Comments
N-1 design criterion	2.5.2.2	Black Flag Zone Substation has exceeded both its N-1 substation and supply capacity.	Manage non-compliance	Due to the variability of mining load demand in the area, Western Power has considered seeking a temporary Technical Rules exemption to avoid costly network augmentation (40km 132 kV circuit and 3rd Substation transformer) until the demand levels can justify the investment.
NCR design criterion	2.5.4 (b)	Meadow Springs Zone Substation	Exemption approved	An exemption has been approved by the ERA to exempt complying with the Normal Cyclic Rating (NCR) criteria at Meadow Springs Substation under the completion of Stage 2 of the Mandurah load area investment strategy. Western Power reviews the forecast Substation capacity utilisation on an annual basis and will trigger these works when required.
N-0 & N-1 design criterion	2.5.2.1 2.5.2.2	The Pinjarra to Alcoa 132 kV circuit can become overloaded during high demand or high generation periods under N-0 and N-1 conditions.	Manage non-compliance	Western Power is currently managing the overload risks with operational practices.
N-1	2.5.2.2	Voltage instability risks exist across the Muja 66 kV network, following the loss of Kojonup to Katanning 66 kV circuit during peak demand conditions.	Manage non-compliance	Declining peak demand forecasts in the area have significantly reduced the risk of voltage instability. In addition, Western Power uses operational practices to further minimise this declining risk.
Fault Levels	2.5.7	A number of 132 kV rated equipment are under rated than the system fault levels (i.e., Mount Lawley, Southern Terminal)	Manage non-compliance	There are 6 remaining 132 kV isolators in Mount Lawley that can become marginally under fault rated. Western Power manages this risk through operational measures and will upgrade these when they reach their end of service life. Due to the highly meshed 132 kV and 330 KV networks the fault rating for plant and earth grid equipment can potentially be exceeded. Current operational practices involve the removal of the Kwinana 330/132 kV bulk transformer from service and bypassing the 132 kV supply from Southern Fremantle and Kwinana by busbar switching under periods of high local generation.
N-1	2.5.2.2	Joondalup to Wanneroo 132 kV circuit following loss of the Neerabup to Northern terminal 132 kV circuit during peak demand conditions.	Manage non-compliance	As this circuit is only marginally over- capacity during maximum demand conditions over the study period, Western Power manages this risk through operational practices to minimise the risk.
N-1 design criterion	2.5.2.2	Voltage instability issues exist on multiple 66 kV and 132 kV busbars in the Picton South area, following the loss of the Picton to Busselton 132 kV circuit during peak demand conditions.	Manage non-compliance / Proposed investment	Western Power submitted a Regulatory Test to the ERA in 2020 for an optimised asset plan that involved the progressive upgrade of the 66 kV supply lines from Picton and Busselton, which would alleviate the voltage stability issues. Although Western Power formally withdrew the Regulatory Test because of reduced demand forecasts, investment is still underway to delivered over by 2030/31. Western Power continues to use operational practices to minimise these risks until the works are completed.

[26] Western Power's proposed amendments to the Technical Rules are available here: https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/proposal-to-amend-western-powers-technical-rules-western-power-30-july-2021-tra6

Theme	TR Clause	Description	Treatment	Comments
N-1 design criterion – Substation capacity	2.5.2.2	A number of substations have exceeded their substation planning capacity	Manage non-compliance	A total of two zone substations (i.e., Bunbury Harbour, Bridgetown) designed to the N-1 criterion have exceeded their substation capacity. Western Power is currently managing this non-compliance and associated risk through operational maintenance that temporarily transfers demand to neighbouring substations through network switching.
NCR design criterion – Substation capacity	2.5.4.2	A number of substations have exceeded their substation planning capacity	Proposed investment	A total of four zone substations (i.e., Clarkson, Henley Brook, Joondalup and Wellington St) designed to the NCR criterion have exceeded their substation capacity. Western Power has proposed investments within the study period to reduce the utilisation levels by either installing additional transformer capacity or offloading the substation to neighbouring substations.
N-1-1	2.5.2.3	Kemerton T1 and T1 Quad Booster transformers are overloaded, following N-1-1 contingencies of Muja BTT1 and Kemerton T2 transformers during peak demand conditions.	Proposed investment	A third 330/132 kV 490 MVA transformer is planned to be installed by 2022/23 that will relieve these overloads.
N-1	2.5.2.2	Kemerton to Marriot Road 132 kV lines, following N-1 contingencies on the parallel line during peak demand conditions.	Proposed investment	Western Power is currently investigating options to increase the capacity to address the thermal constraints and accommodate increase demand in the area.
Under Frequency Load Shedding (UFLS) scheme[27]	2.3.2 (a), 2.4.1	Western Power UFLS load shedding levels are unable to meet the 75 % at all times requirement	Proposed investment	As part of Action 10 of the DER Roadmap, Western Power, in with collaboration with AEMO, are validating the performance of the current design of the UFLS scheme. A series of investments are underway to increase the level of UFLS load shedding that is rapidly declining due to the increased levels of rooftop solar PV capacity. Future stages of investment are anticipated to work towards achieving compliance to the current design.

[27] As of the 1 July, the UFLS requirements and obligations to meet them have transition to section 3 of the WEM Rules.

9 Key Network (Region) Strategies

Western Power's network covers the area from Kalbarri in the north to Albany in the south, and from Kalgoorlie in the east to the metropolitan coast.

Western Power's network has been segmented into six geographic regions for the purposes of network planning. Dividing networks into regions is designed for ease of network planning as these regions can share similar load characteristics and experience shared network issues.

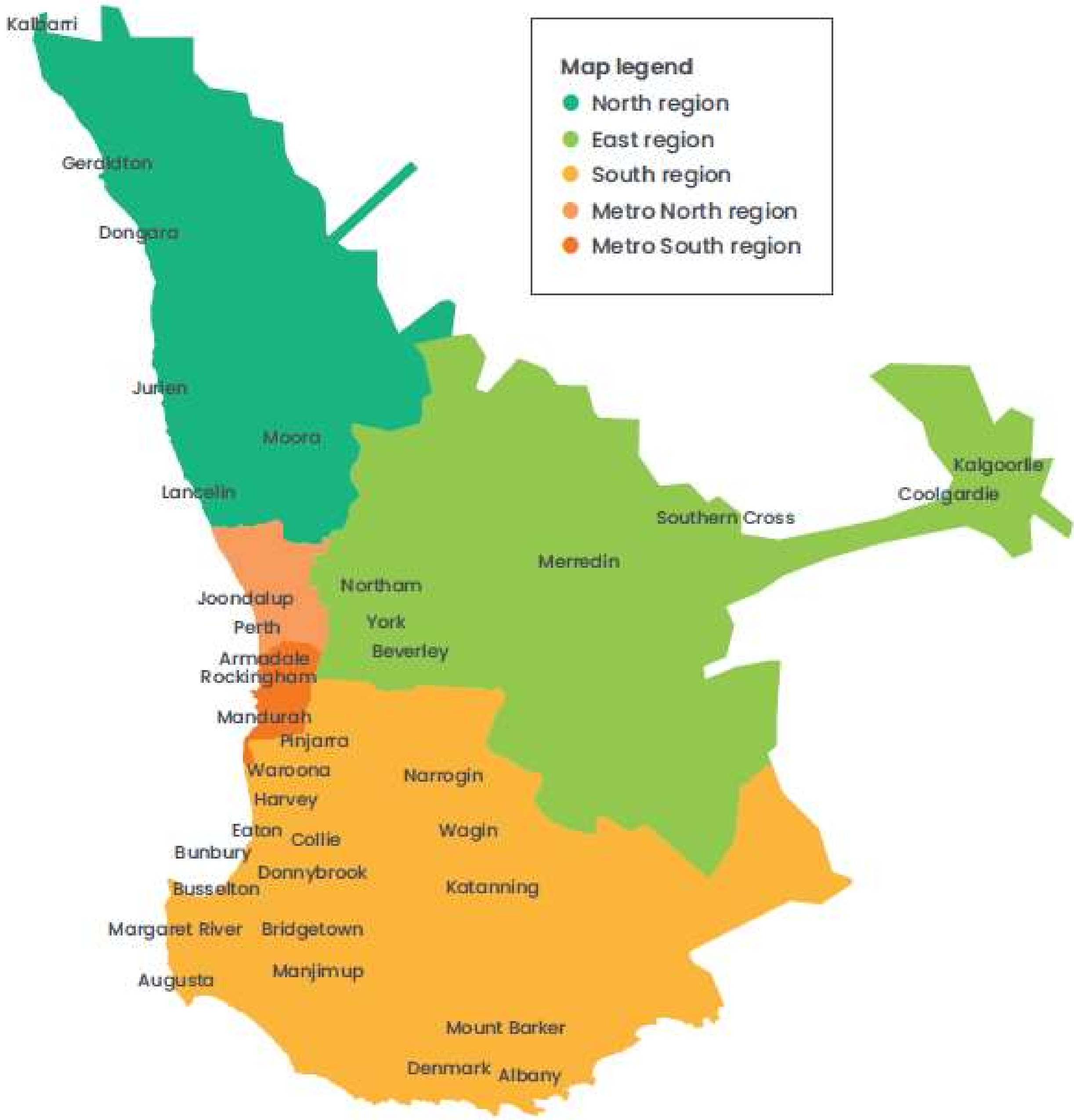

Figure **12** provides an illustration of the geographic boundaries between regions, with three regions covering the metro and three regions covering the remaining regional parts of the SWIS.

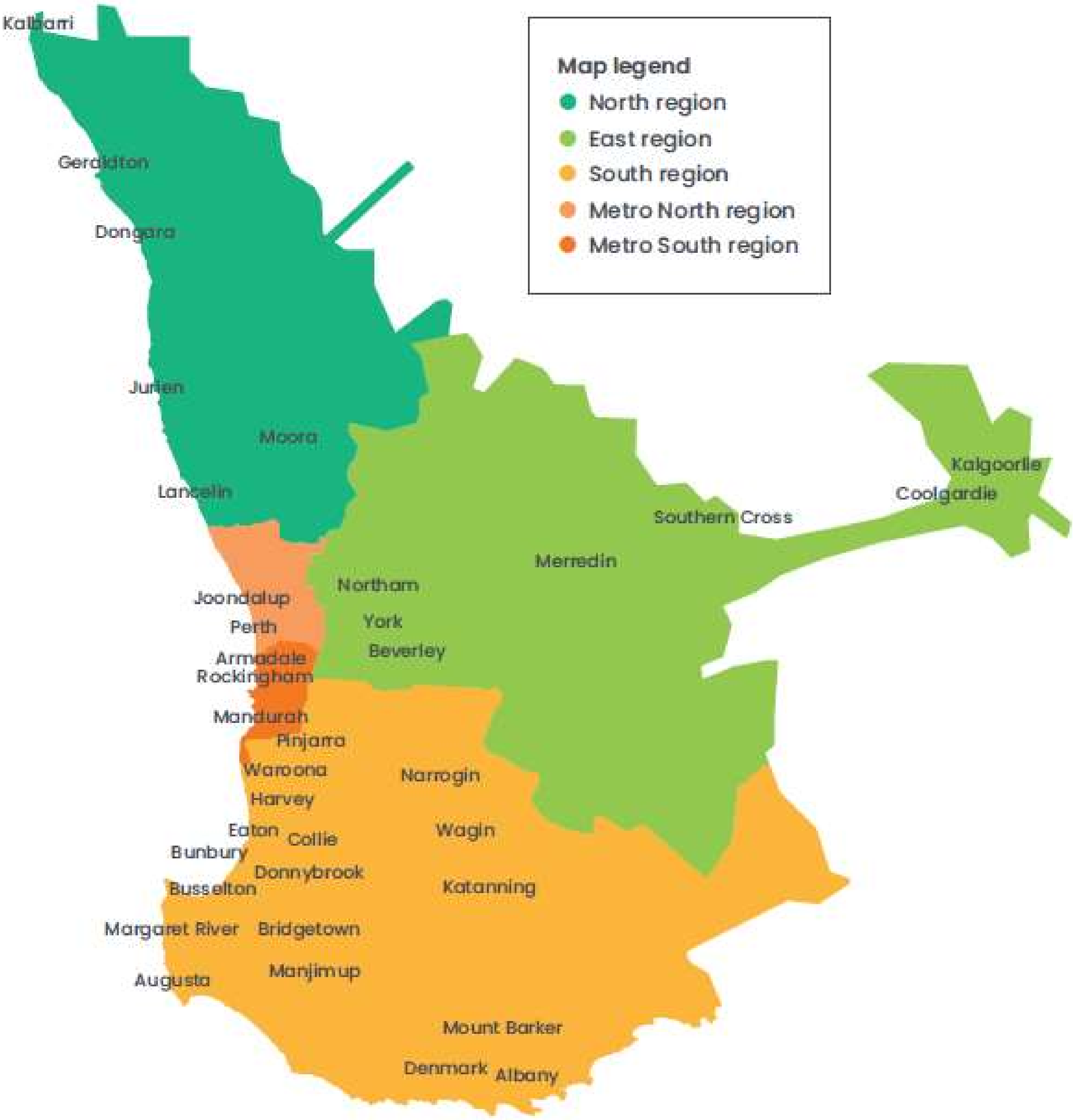

Figure 12: Western Power's transmission network regions

Each of the six regions in the SWIS are discussed in detailed throughout sections 10 to 15 . These sections include:

- A description of key regional characteristics of the region including:
  - geographical boundary
  - the type of load and generation mix
  - existing network supply
  - key developments.
- An overview of network performance levels including the following performance parameters:
  - thermal capacity

- voltage capacity
- fault levels
- stability
- reliability
- asset condition (major network assets only).

- A list of Western Power's optimised (completed, committed and proposed) network development plans (considering both network and non-network options) to address the identified network constraints over the study period.
- A list of network opportunities to provide alternative options to alleviate or reduce network constraints and subsequent proposed network augmentation. For more information relating to what is a network opportunity and how and when to submit an alternative option, refer to the NOM 2022.

10 North Region

10.1 Geography

The North Region covers the northern most part of the Perth metropolitan area, from Landsdale and Wangara in the south to Yanchep in the north, extending into northern rural areas via Pinjar and Muchea, and to Geraldton at the northern extremity of the Western Power transmission network. The North Region extends inland about 150 km to service the northern wheatbelt.

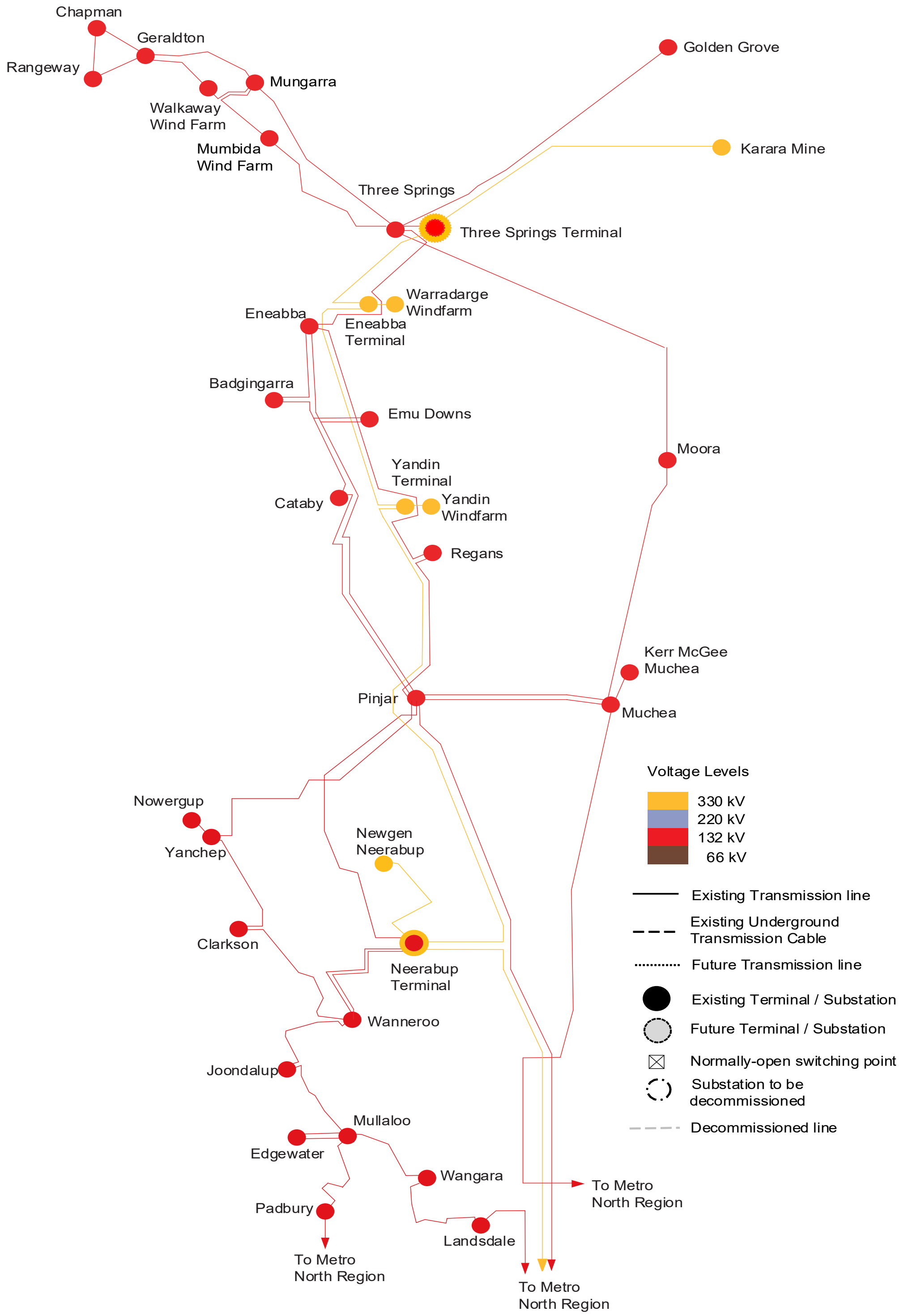

Figure 13: Western Power's North Region – Network Diagram

Western Power's North Region has four terminal stations and 17 zone substations that are owned and operated by Western Power. The other transmission sites in the North Region are customer owned substations.

Terminal substations

- Eneabba Terminal – 330/132 kV
- Three Springs Terminal – 330/132 kV
- Neerabup Terminal – 330/132 kV
- Yandin Terminal – 330/132 kV

Zone Substations / WP Substations

- Chapman – 132/11 kV
- Clarkson – 132/22 kV
- Eneabba – 132/33 kV
- Geraldton – 132/33 kV
- Joondalup – 132/22 kV
- Rangeway – 132/11 kV
- Regans – 132/33/22 kV
- Landsdale – 132/22 kV
- Moora – 132/33 kV
- Muchea – 132/22 kV
- Mullaloo – 132/22 kV
- Padbury – 132/22 kV
- Pinjar - 132kV (switchyard)
- Three Springs – 132/33 kV
- Wangara – 132/22 kV
- Wanneroo – 132/22 kV
- Yanchep – 132/22 kV

Customer Substations

- Badgingarra – 132 kV
- Cataby – 132 kV
- Edgewater – 132 kV
- Golden Grove – 330 kV
- Kerr McGee Muchea – 132 kV
- Karara Mine – 330 kV
- Mungarra – 132k kV
- Mumbida WF – 132 kV
- Nowergup – 132 kV
- Walkaway WF - 132kV
- Warrradarge WF – 330 kV
- Yandin WF – 330 kV

10.2 Regional Characteristics

10.2.1 General

The network covering the northern most part of the Perth metropolitan area supplies predominantly residential loads and a mixture of commercial and light industrial loads.

The network covering the area further north of the Perth Metropolitan area primarily supplies rural, agricultural and mining loads with urban areas concentrated in the City of Geraldton and Kalbarri in the most northern part of the network.

10.2.2 Generation

There is about 800MW of renewable generation in the region. In addition, there is also significant gas-fired generation at Neerabup terminal, Pinjar and Mungarra[28]. Due to the availability of fuel resources in the North, particularly wind and other renewable sources, this region has the potential to become a significant exporter of energy. However, the current transfer capacity is significantly utilised and generation in this region is likely to be subject to network congestion until further network augmentation to improve the transfer capability is justified.

10.2.3 Existing Transmission Network Supply

The North Region transmission network consists of a mix of 330 kV and 132 kV networks. The 330 kV networks provide bulk power transfer capability through the region and the 132 kV networks primarily provide supply to load centres. The 330 kV networks are linked to the 132 kV networks via the Neerabup and Three Springs terminal stations. The 330 kV networks and 132 kV networks in the region are planned and operated to a N-1 standard, other than some mining load customer connections that have N-0 supply arrangements.

10.2.4 Key Developments In the Region

Large-scale windfarms were recently connected at Warradarge and Yandin on the 330 kV network and at Badgingarra on the 132 kV network. Despite network constraints in the region, GIA has enabled the connection of the windfarms under an interim constrained network access regime.

There has been considerable interest in new network connections for new large-scale wind and solar facilities in the northern areas, where wind and solar energy sources and available land are relatively abundant.

10.3 Performance

This section presents the network performance for the North Region over the study period.

10.3.1 Thermal Capacity - Boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and security constrained and economic dispatch conditions.
- Export boundaries consider peak demand and maximum generation dispatch conditions (within boundary).

[28] Currently Mungarra is only utilised for network control services

Import Boundaries

Figure 14 **highlights the network import boundaries in the North Region. These boundaries are defined using the worst contingency ( ) and the worst overload circuit (*) as shown in**

Table 3.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 15 to Figure 18.

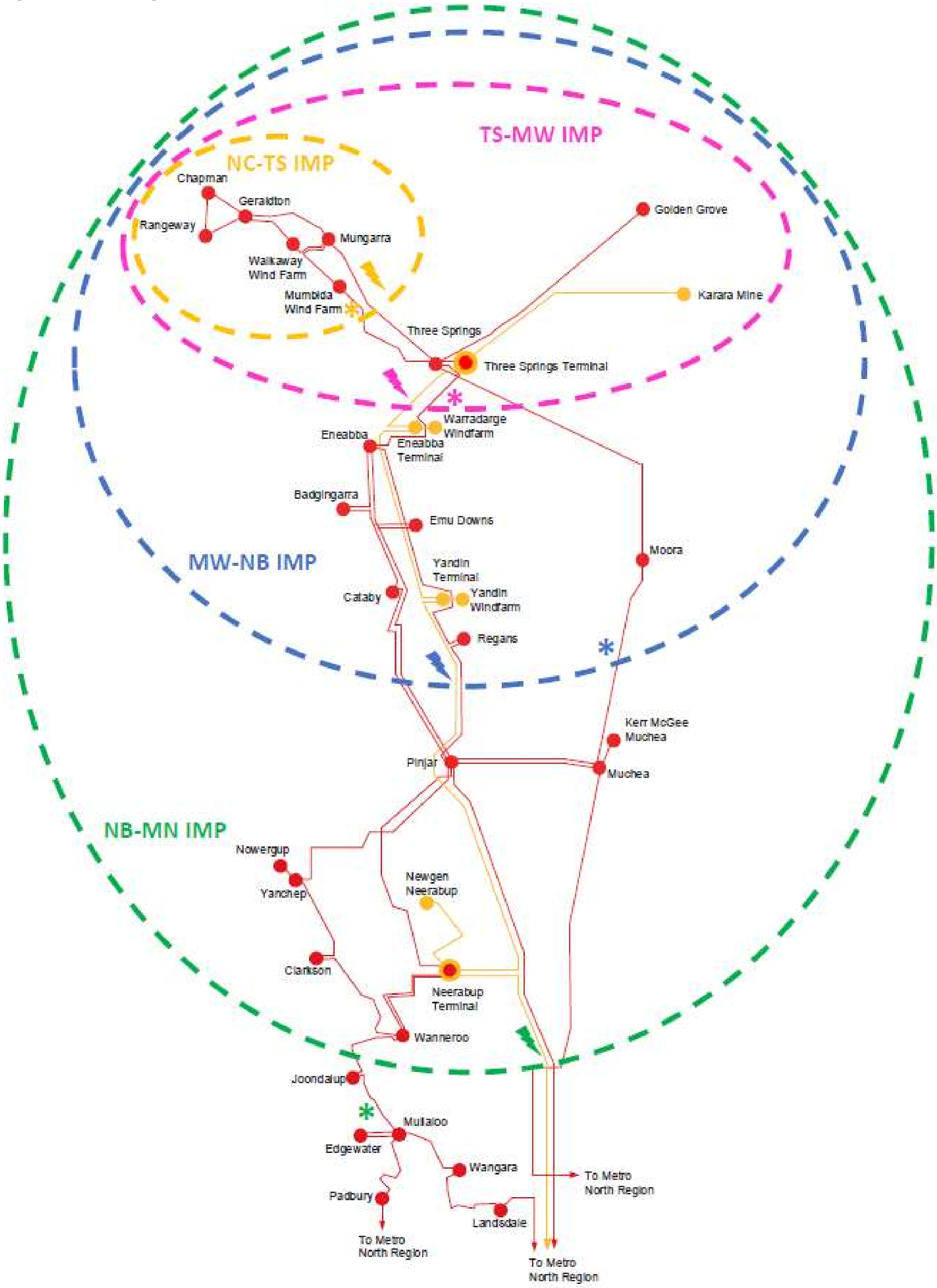

Figure 14: Network thermal import boundaries in the North Region

Table 3: Thermal import boundaries characteristics – North Region

Characteristics	Import Boundaries			
	NC-TS IMP	TS-MW IMP	MW-NB IMP	NB-MN IMP
Worst contingency	Three Springs to Mungarra 132 kV line	Eneabba Terminal to Three Springs Terminal 330 kV line	Neerabup Terminal to Yandin Terminal 330 kV line	Northern Terminal to Neerabup Terminal 330 kV line
Contingency type	N-1	N-1	N-1	N-1
Worst circuit	Three Springs to Mumbida 132 kV line	Three Springs to Eneabba 132 kV line	Muchea to Moora 132 kV line	Mullaloo to Joondalup 132 kV line

Other than for the NC-TS IMP boundary, it is important to note that the available thermal capacity in the remaining import boundaries may be lower than shown, as a new load connection looking to connect within a subset import boundary may bind first (i.e., at either the transmission network or substation level).

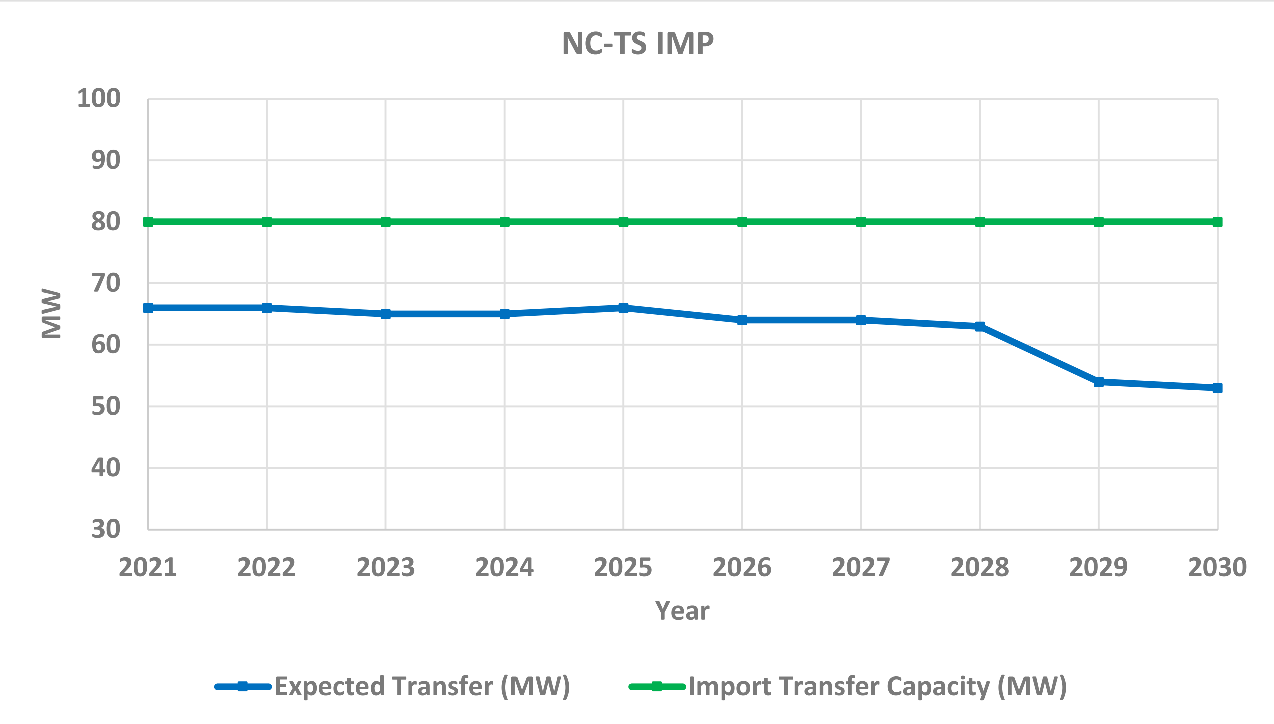

Figure 15: Expected transfer and transfer capacity in NC-TS IMP boundary – peak demand

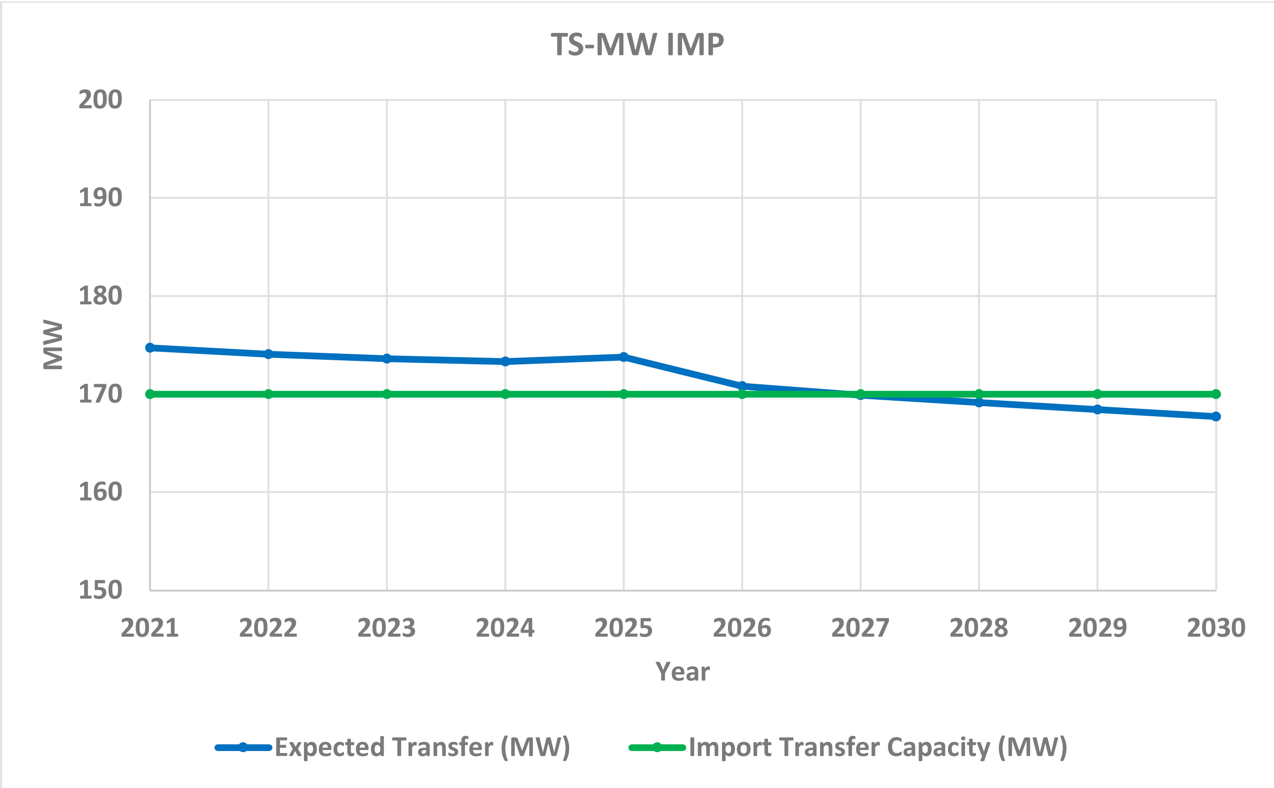

Figure 16: Expected transfer and transfer capacity in TS-MW IMP boundary – peak demand

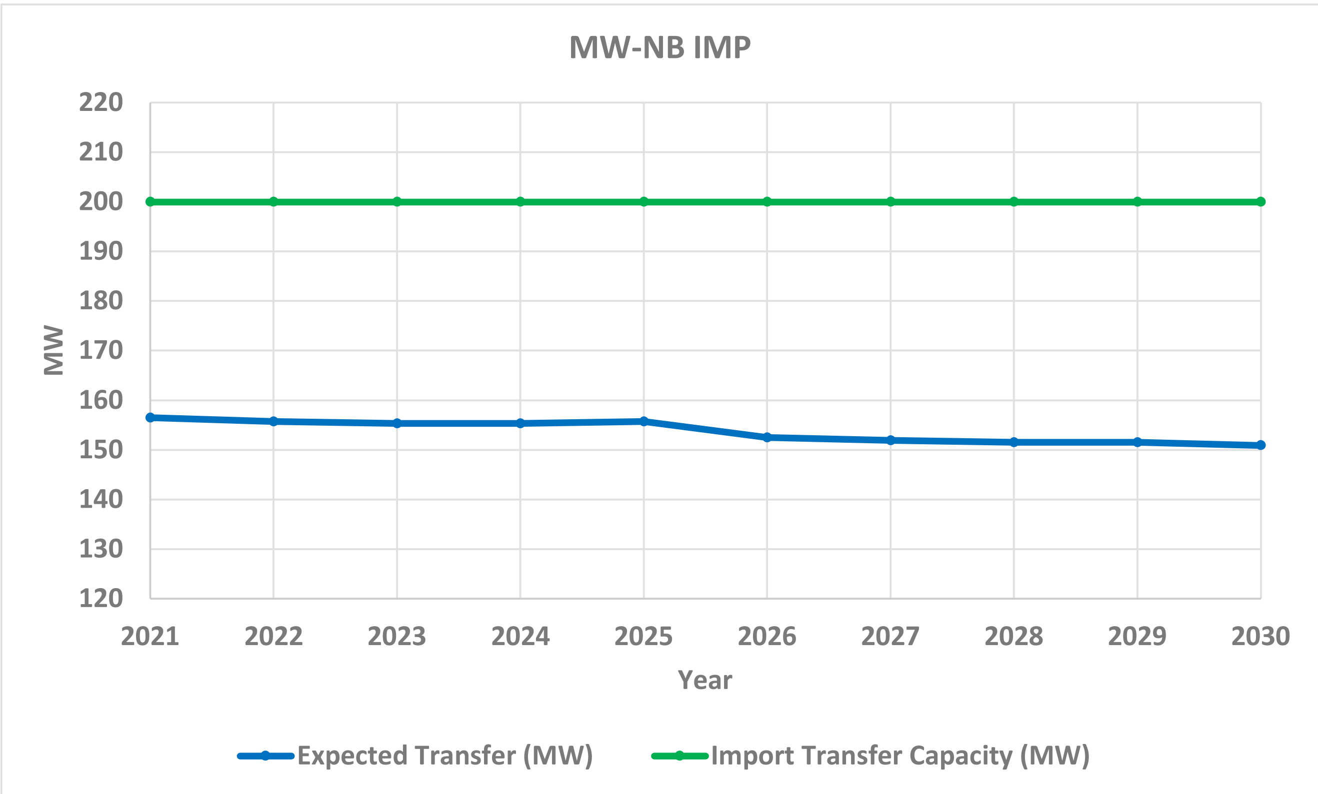

Figure 17: Expected transfer and transfer capacity in MW-NB IMP boundary – peak demand

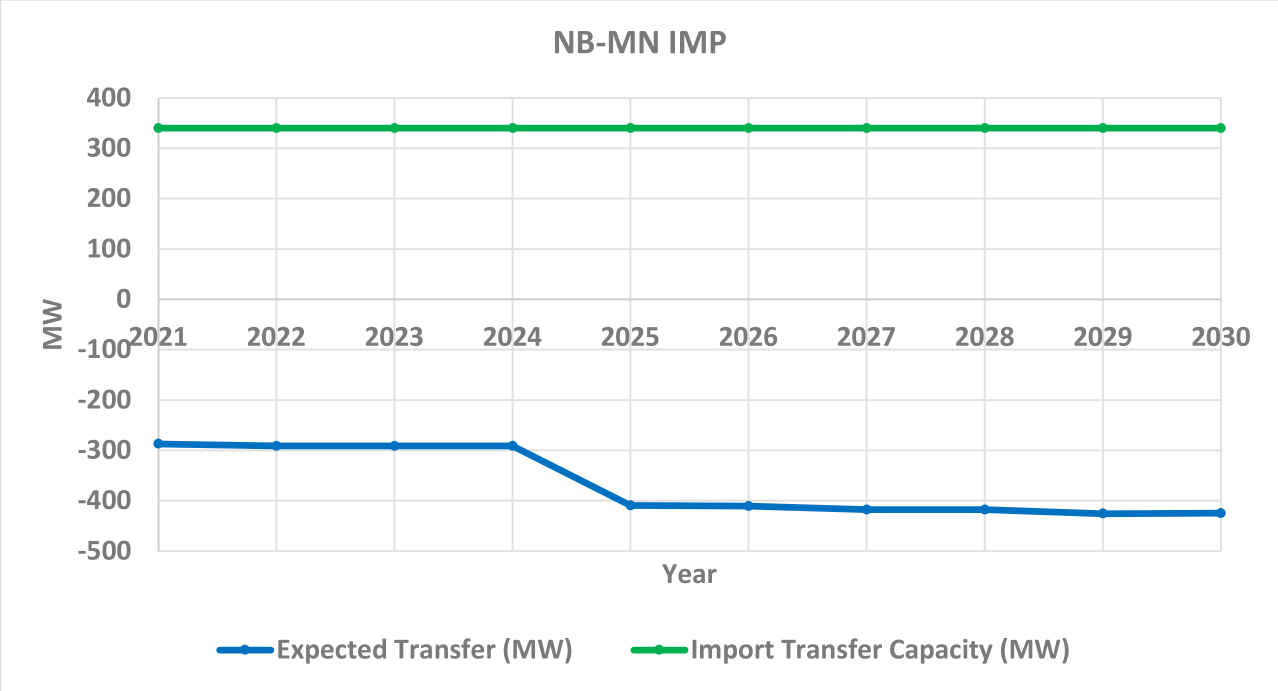

Figure 18: Expected transfer and transfer capacity in NB-MN IMP boundary – peak demand

The above figures illustrate that there is no available import capacity within the TS-MW import boundary, due to limitations on the 132 kV network. In addition, there is limited available import capacity across the remaining NC-TS, MW-NB boundaries during the study period. Despite available capacity being observed within the NB-MN boundary, this is limited to new loads that are installed between the NB-MN and MW-NB boundaries otherwise the transfer capacities within the subset boundaries may be exceeded.

Export Boundaries

Figure 19 highlights the network export boundaries in the North Region. These boundaries are defined using the worst contingency ( ) and the worst overload circuit (*) as shown in Table 4.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 20 - Figure 23.

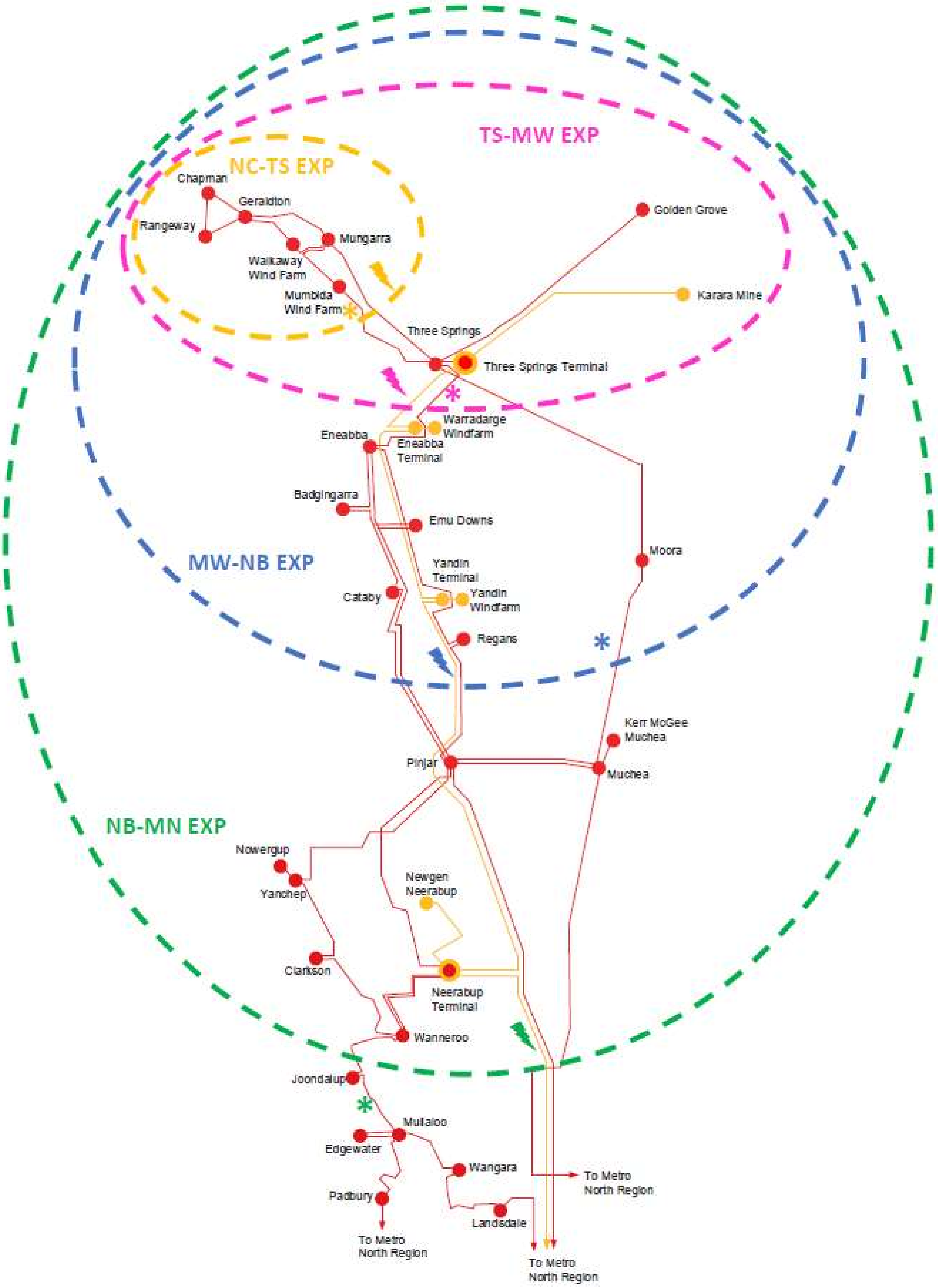

Figure 19: Network thermal export boundaries in the North Region

Table 4: Thermal export boundaries characteristics – North Region

Characteristics	Export Boundaries			
	NC-TS EXP	TS-MW EXP	MW-NB EXP	NB-MN EXP
Worst contingency	Three Springs to Mungarra 132 kV line	Eneabba Terminal to Three Springs Terminal 330 kV line	Neerabup Terminal to Yandin Terminal 330 kV line	Northern Terminal to Neerabup Terminal 330 kV line
Contingency type	N-1	N-1	N-1	N-1
Worst circuit	Three Springs to Mumbida 132 kV line	Eneabba to Three Springs 132 kV line	Muchea to Moora 132 kV line	Henley Brook to Muchea 132 kV line

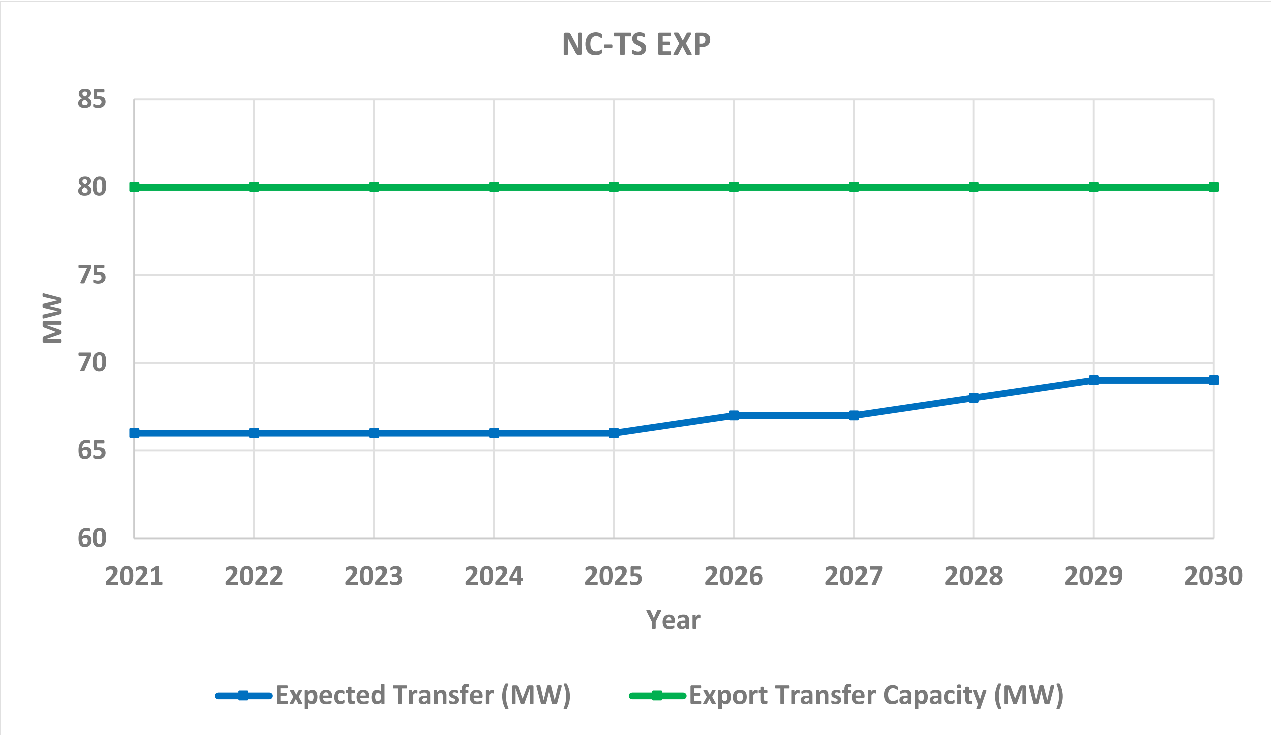

Figure 20: Expected transfer and transfer capacity in NC-TS EXP boundary – peak demand

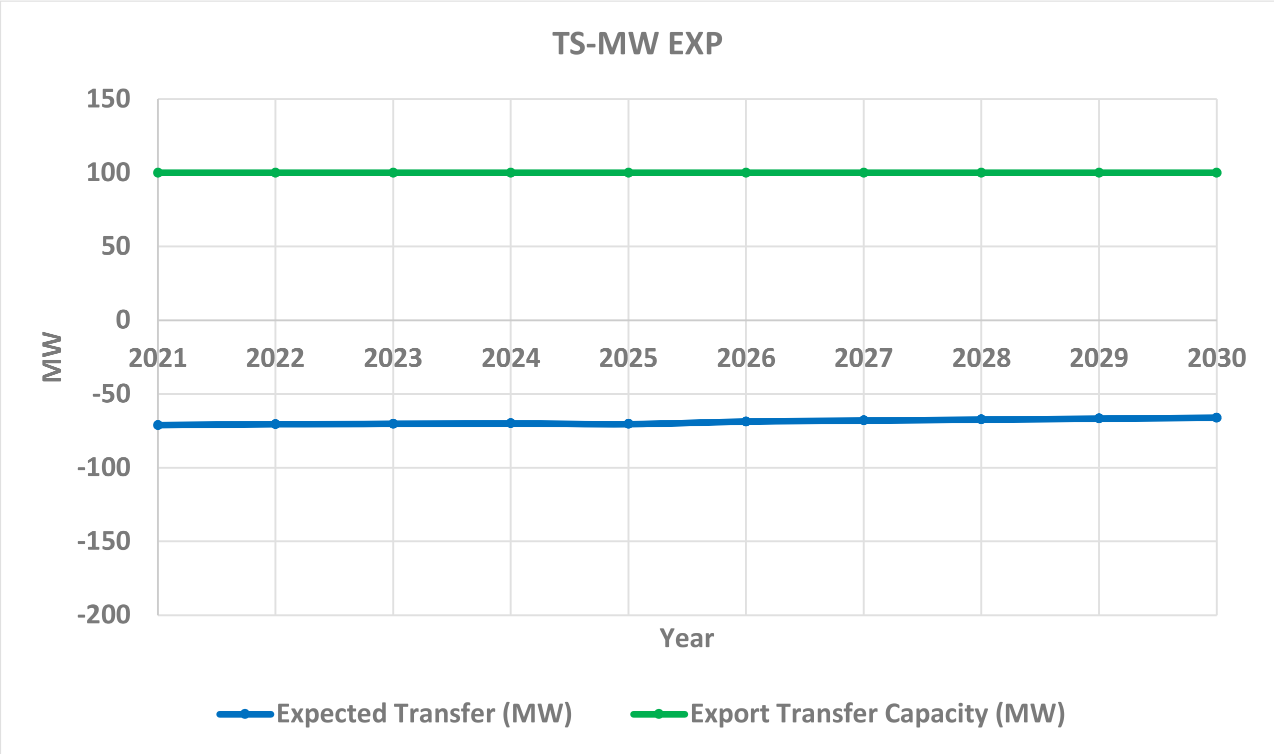

Figure 21: Expected transfer and transfer capacity in TS-MW EXP – peak demand

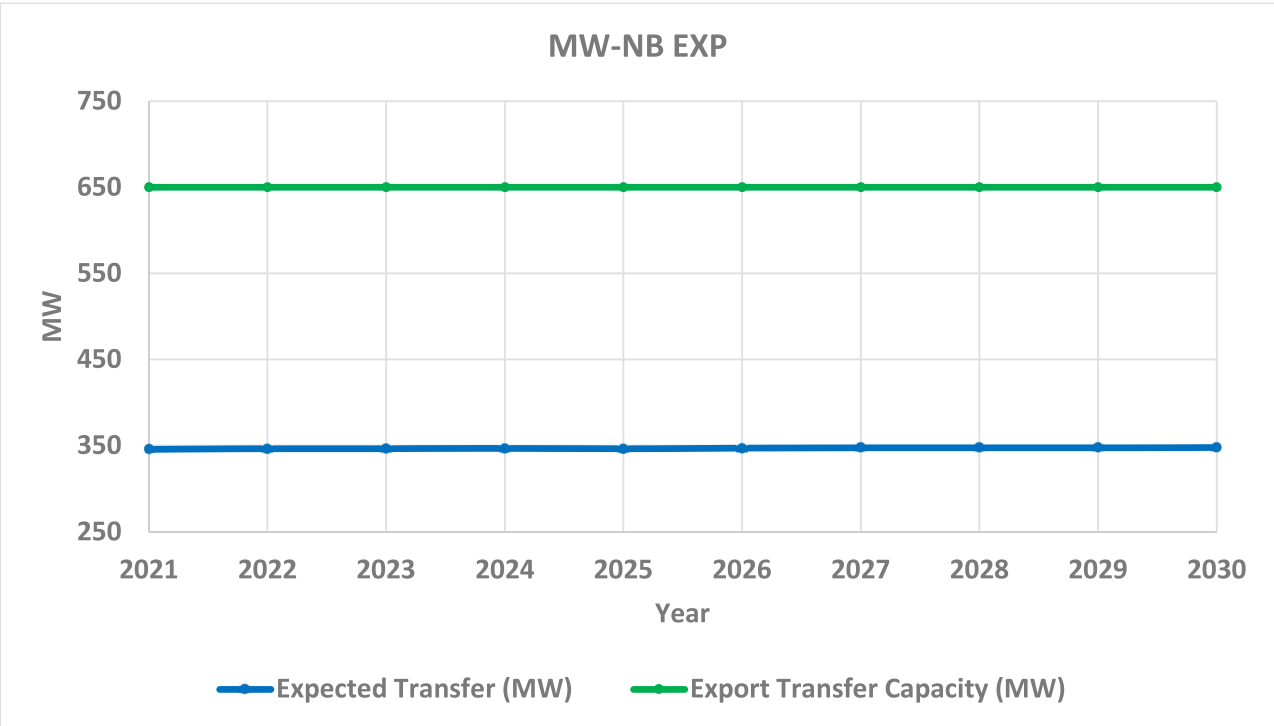

Figure 22: Expected transfer and transfer capacity in MW-NB EXP boundary – peak demand

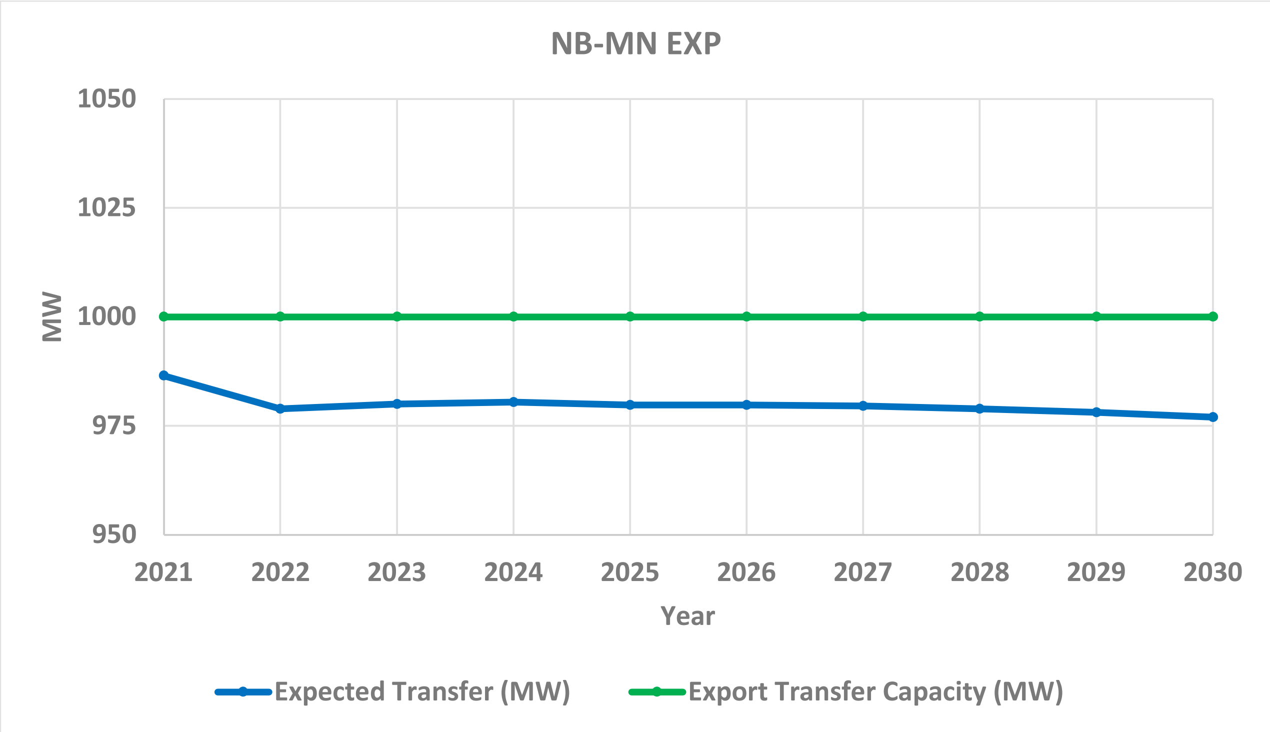

Figure 23: Expected transfer and transfer capacity in NB-MN EXP boundary – peak demand

The above figures illustrate that new generation connection for the NC-TS and NB-MN boundaries are very limited and likely to trigger the need for network augmentation to unleash additional capacity. With abundant renewable fuel resources in the area, new generation connections are likely to increase congestion issues within this region. The frequency and magnitude of these constraints will be monitored and used in future TSPs to determine the point at which network augmentation becomes more economically efficient when compared with dispatching higher cost generators in the market.

The power flows in TS-MW are negative, indicating that this boundary is a net importer of power during high generation and peak demand conditions. This boundary and MW-NB have available capacity to support new generation connections.

10.3.2 Thermal Constraints - Transmission Lines

Post contingent thermal overloads exist and emerge over the study period on the following circuits:

- Existing 132 kV Three Springs Substation busbar overloads exist, following the loss of the Three Springs to Three Springs Terminal 132 kV and Three Springs to Eneabba Terminal 330 kV circuits (N-1-1), during both peak and minimum demand conditions when renewable generation output is high[29].
- Neerabup Terminal to Wanneroo 132 kV line overloads occur by 21/22 and increases up to 110 per cent, following the loss of the Northern Terminal Transformer 2 in peak demand conditions.

In addition, a number of post contingent thermal overloads arise over the study period during peak demand conditions. Western Power currently manages these thermal constraints through operational

29 These constraints are managed by post-contingent generation runback schemes that are designed to curtail the intermittent generation in the area to prevent network security related issues.

measures that take the Neerabup Terminal 330/132 kV transformer out of service however, under certain operating conditions this may[30] not be a suitable action:

- Joondalup to Wanneroo 132 kV line overloads occur by 22/23 and increases up to 101 per cent, following the loss of the Henley Brook to Muchea 132 kV line
- Joondalup to Wanneroo 132 kV line overloads occur by 22/23 and increases up to 102 per cent, following the loss of the Northern Terminal to Landsdale 132 kV line
- Joondalup to Wanneroo 132 kV line overloads occur by 22/23 and increases up to 114 per cent, following the loss of the Northern Terminal to Pinjar 132 kV line
- Joondalup to Wanneroo 132 kV line overloads occur by 22/23 and increases up to 103 per cent, following the loss of the Northern Terminal Transformer T1
- Mullaloo to Joondalup 132 kV line overloads occur by 20/21 and increases up to 105 per cent, following the loss of the Northern Terminal to Pinjar 132 kV line
- Neerabup Terminal to Wanneroo 132 kV line overloads occur by 20/21 and increases up to 105 per cent, following the loss of the Clarkson to Yanchep 132 kV line
- Neerabup Terminal to Wanneroo 132 kV line overloads occur by 20/21 and increases up to 102 per cent, following the loss of the Northern Terminal Transformer T1
- Neerabup Terminal to Wanneroo 132 kV line overloads occur by 20/21 and increases up to 115 per cent, following the loss of the Pinjar to Yanchep 132 kV line
- Pinjar to Muchea 132 kV line 82 overloads occur by 22/23 and increases up to 101 per cent, following the loss of the Pinjar to Muchea 132 kV line 81
- Pinjar to Yanchep 132 kV line overloads occur by 22/23 and increases up to 104 per cent, following the loss of the Neerabup Terminal to Wanneroo 132 kV line.

10.3.3 Thermal Capacity – Transformers

This section shows existing utilisation and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the North Region. Table 5 highlights the different substation utilisation classifications. As substations become highly utilised Western Power will typically investigate and develop cost-effective options to alleviate a potential capacity constraint. Network solutions range from network switching, distribution transfers to neighbouring under-utilised substations and substation transformer capacity upgrades. Non-network options, such as demand-side management solutions are also considered.

As utilisation levels increase toward being over utilised, proposed network plans develop into projects. Western Power also develops contingency plans to minimise the associated risks of a transformer failure prior to completion of a project.

Table 5: Utilisation legend (for Table 6)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

30 Removal of the Neerabup Terminal transformer during high wind output conditions can increase the size of the largest single contingency, which presents increased risks to maintaining frequency stability. It also is not possible during planned outages in the area as it impacts the GIA and the ability to maintain system security.

Table 6: North Region: Zone Substation utilisation heat map

	Sub Capacity	Actual Utilisation (%)	Forecast Utilisation (%)																				Comments
Substation	Current MVA	2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
			POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	
Clarkson[31]	56	129	117	101	117	101	117	101	116	101	116	100	115	100	115	99	114	99	114	98	113	98	Additional transformer (Scoping, RIS year 2024)
Chapman	31	43	44	41	43	41	43	40	43	40	42	40	42	40	42	40	42	40	42	39	42	39	
Eneabba	31	31	30	23	29	23	29	22	29	22	29	22	30	23	30	23	30	23	30	24	30	24	
Geraldton	65	45	54	46	54	46	54	46	53	45	52	44	52	43	51	43	50	42	50	41	49	41	
Joondalup[31]	53	102	105	86	107	88	109	89	111	90	112	92	114	93	116	94	117	95	119	96	121	98	Additional transformer (Scoping, RIS year 2025)
Landsdale	88	89	89	80	89	80	89	80	89	79	89	79	88	79	88	79	88	79	88	79	88	79	
Moora	16	89	95	88	96	87	96	87	97	87	97	88	98	88	99	88	99	88	100	88	100	88	
Muchea	51	52	52	50	52	50	53	50	53	50	53	51	54	51	54	51	54	51	54	52	55	52	
Mullaloo	66	78	76	70	76	69	75	69	74	68	74	68	74	68	73	67	73	67	72	67	72	67	
Padbury	82	80	71	65	72	65	72	65	73	65	73	65	74	65	75	65	75	65	76	65	76	65	
Rangeway	69	51	44	37	46	38	47	38	48	39	49	40	50	40	51	41	53	41	54	42	55	43	
Regans 22 kV	19	55	54	52	53	50	52	50	53	51	55	52	56	54	58	55	59	56	61	58	62	59	
Regans 33 kV	19	73	52	45	52	45	53	45	53	46	53	46	54	47	54	47	54	47	55	48	55	48	
Three Springs	16	54	58	51	59	52	60	53	61	54	62	55	63	56	63	56	64	57	65	58	66	59	
Wangara	28	73	81	76	83	79	86	82	89	85	92	87	95	90	97	93	100	96	103	99	105	101	Managed by distribution transfers
Wanneroo	84	60	70	61	70	61	70	61	69	61	69	60	69	60	69	60	69	60	69	60	69	60	
Yanchep	61	69	68	62	69	63	71	64	73	64	76	65	79	66	81	67	84	67	87	68	90	69	

31 Western Power is developing contingency plans to manage the substation capacity shortfall risks prior to the installation of an additional transformer

10.3.4 Steady State Voltages

Voltage related performance constraints within the North Region arise during peak demand conditions over the study period, including:

- Low voltages (0.8pu) by 2020/21 at the Three Springs Terminal 330 kV busbar, following the loss of the Eneabba Terminal to Three Springs Terminal 330 kV line.

Voltage related performance constraints also arise within the North Region during minimum demand conditions over the study period, including:

- High voltages (1.11pu) by 2028/29 at the Neerabup Terminal 330 kV and Yandin Terminal 330 kV busbars, following the loss of Bluewaters Power Station G1 or G2.
- High voltages (1.11pu) and excessive voltage step conditions (+8-9 per cent) arise by 2025/26 at the Chapman, Geraldton, Mumbida, Mungarra, Rangeway and Walkaway 132 kV busbars, following the loss of the Three Springs Terminal transformer T1.
- High voltages (1.11pu) and excessive voltage step conditions (+8-9 per cent) arise by 2025/26 at the Chapman, Geraldton, Mumbida, Mungarra, Rangeway and Walkaway 132 kV busbars, following the loss of the Three Springs Terminal to Three Springs 132 kV line.

10.3.5 Fault Levels

There are no fault level related performance constraints within the North Region over the study period.

10.3.6 Stability

Due to the growing levels of inverter-based generation in the North Region, Western Power conducted N-0 system strength studies for all existing facilities in the region. The results observed that all facilities are expected to retain control loop stability.

Though the existing N-0 studies have not revealed any system strength limitations, given the limited number of synchronous generators in parts of the networks, Western Power expects that system strength issues will materialise under certain contingency conditions. Solutions to these issues could include retuning of the control parameters of a facility, installation of stabilising equipment (e.g., BESS, STATCOM, synchronous condensers) or operational constraints.

Further work is ongoing to refine the EMT models and undertake system studies for contingency conditions in the North Region.

10.3.7 Reliability

Although designed and operated to a N-1 standard, lower levels of historical reliability performance with the aged and older construction standard 132 kV transmission lines from Three Springs Zone Substation to Mumbida and Mungarra plus prolonged outage times have triggered the need for Western Power to procure a Network Control Service with Synergy. This service is designed to enable the 132 kV network north of the Three Springs Zone Substation to operate as an island, following the loss of both 132 kV transmission lines[32] from Three Spring. Historical and future performance is shown in Figure 24.

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32 A large portion of these 132kV circuits are built with legacy "cricket wicket' structures that are more prone to failure in strong wind conditions.

Figure 24: NCS operation in the North Region

10.3.8 Asset

Existing asset performance constraints were identified in the North Region within the study period, including:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
  - Geraldton– 132/22 kV, 33 MVA - T1 and T3
  - Regans– 33/22 kV, 15 MVA – T4
  - Three Springs– 132/33 kV, 13 MVA – T1 and T3
- One of the 11 kV switchboards at Chapman Substation is in degraded condition and needs to be addressed in the next 10 years.
- A large portion of the assets on the 132 kV transmission line from the Three Springs Zone Substation to Mungarra are in degraded condition and need to be addressed within the study period. Western Power is currently investigating replacement plans, including options to increase capacity to accommodate future demand and customer connections in the area.

10.4 Network Augmentation Works

Committed, completed and proposed transmission projects in the North Region are shown in Table 7.

Table 7: Completed, committed and proposed projects - North Region

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Mullaloo substation: Transformer Replacement	Replace existing 132/22 kV T1 transformer at Mullaloo zone Substation	Address degraded asset conditions	Asset condition	2021/22	Completed
Durlacher Substation: Decommission Substation	Decommissioning of the 132 kV Durlacher Substation and supply lines, including load transfers to Chapman Substation	Address degraded asset condition issues	Asset condition	2021/22	Completed
Neerabup Terminal and Guildford Terminal voltage rectification - Stage 2	Installation of 2 x 25 MVAr Decommission shunt reactors at Neerabup Terminal and Guildford Terminal.	Address existing reactive power shortfall and minimise the risk of overvoltages during system minimum demand conditions.	Growth - Voltage	2021/22	Completed
Geraldton Substation: 33 kV switchyard asset replacement	Replace 33 kV switchyard assets at Geraldton Zone Substation	Address degraded asset condition issues	Asset condition	2023/24	Execution
Clarkson Substation: Additional transformer	Installation of a third 132/22 kV 33 MVA transformers at Clarkson Substation.	Address existing substation capacity shortfall and accommodating increase demand in the area	Growth - Thermal	2023/24	Scoping
Joondalup Substation: Additional transformer	Installation of a third 132/22 kV 33 MVA transformers at Clarkson Substation.	Address existing substation capacity shortfall and accommodating increase demand in the area	Growth - Thermal	2024/25	Scoping
North Region: NCS contract	A NCS contract to call upon standby generation in the North Region upon the loss of both supplies north of Three Springs.	Improve the level of reliability service provided to customers in Geraldton and surrounding areas, following the loss of both 132 kV supply circuits between Three Springs and Mungarra.	Reliability	2023/24	Execution

10.5 Network Opportunities

This section highlights the network opportunities in the North Region over the study period.

Table 8: Network Opportunities projects - North Region

Project	Scope/Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Clarkson Substation: Additional transformer	Installation of a third 132/22 kV 33 MVA transformers at Clarkson Substation.	To reduce demand in the area to eliminate, reduce of defer the need for additional transformer capacity.	2023/24	Scoping	9-12
Joondalup Substation: Additional transformer	Installation of a third 132/22 kV 33 MVA transformers at Clarkson Substation.	To reduce demand in the area to eliminate, reduce of defer the need for additional transformer capacity.	2024/25	Scoping	9-12
North Region: NCS contract	A NCS contract to call upon standby generation in the North Region upon the loss of both supplies north of Three Springs.	In the short-term, an opportunity exists to provide standby generation under an NCS contract arrangement to improve the level of reliability of supply to these areas. These NCS contracts are up for renewing at the end of 2022/23. Over the longer-term, reduce demand in the area to eliminate, reduce of defer the need for rebuilding the existing legacy transmission lines in the region that to remove the need for an NCS.	2023/24	Execution (existing NCS contract) / Initiation (Renewal of NCS/network augmentation)	~100[33]
MW-NB and NB-MN available import capacity	Spare available import capacity exists over a number of import boundaries within the North Region.	An opportunity exists to utilise spare available capacity within MW-NB and NB-MN import boundaries by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a
TS-MW and MW-NB available export capacity	Spare available export capacity exists over a number of export boundaries within the North Region.	An opportunity exists to utilise spare available capacity within the TS-MW and MW-NB export boundaries by connecting new generation.	Across the study period	n/a	n/a

10.6 Emerging Issues and Drivers

Despite existing thermal capacity limitations in the North Region network, there is still limited spare capacity across parts of the region, as described in section 10.3. In the short-term and prior to the commencement of the constrained network access model, the GIA continues to provide prospective generators a flexible option to connect under a non-reference service.

Over the medium to longer term, the combination of relatively high availability of land and local wind and solar fuel resources mean the region has the potential to become a significant exporter of energy. This is likely to increase congestion issues within the region. The frequency and magnitude of these constraints will be monitored and used in future TSPs to determine the point at which network augmentation becomes more economically efficient when compared with dispatching higher cost generators in the market.

New generation connections are anticipated to drive major network augmentation to provide additional bulk power transfer capacity from the North Region into the Perth Metro area, which may be accelerated

[33] Estimated cost of rebuilding the three circuits from Three Springs to Mungarra with an overhead earth wire.

because of the WA State Government’s announcement to retire remaining coal-fired generation at the Muja and Collie power stations. The conversion of the second 330 kV circuit (currently operating at 132 kV) from the Northern Terminal through to Three Springs is a potential option for consideration.

Over the longer term, electrification of industries and decarbonisation developments are also expected to drive significant increases in import and export transfer capacity in the North Region, including potential large-scale renewable, storage infrastructure and green hydrogen production facilities.

11 South Region

11.1 Geography

The South Region covers the Great Southern and Southern West part of the Western Power transmission network. The west part of this region covers from Alcoa Pinjarra in the north to Augusta in south. The east part of the region 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.

Figure 25 shows the transmission system in this region.

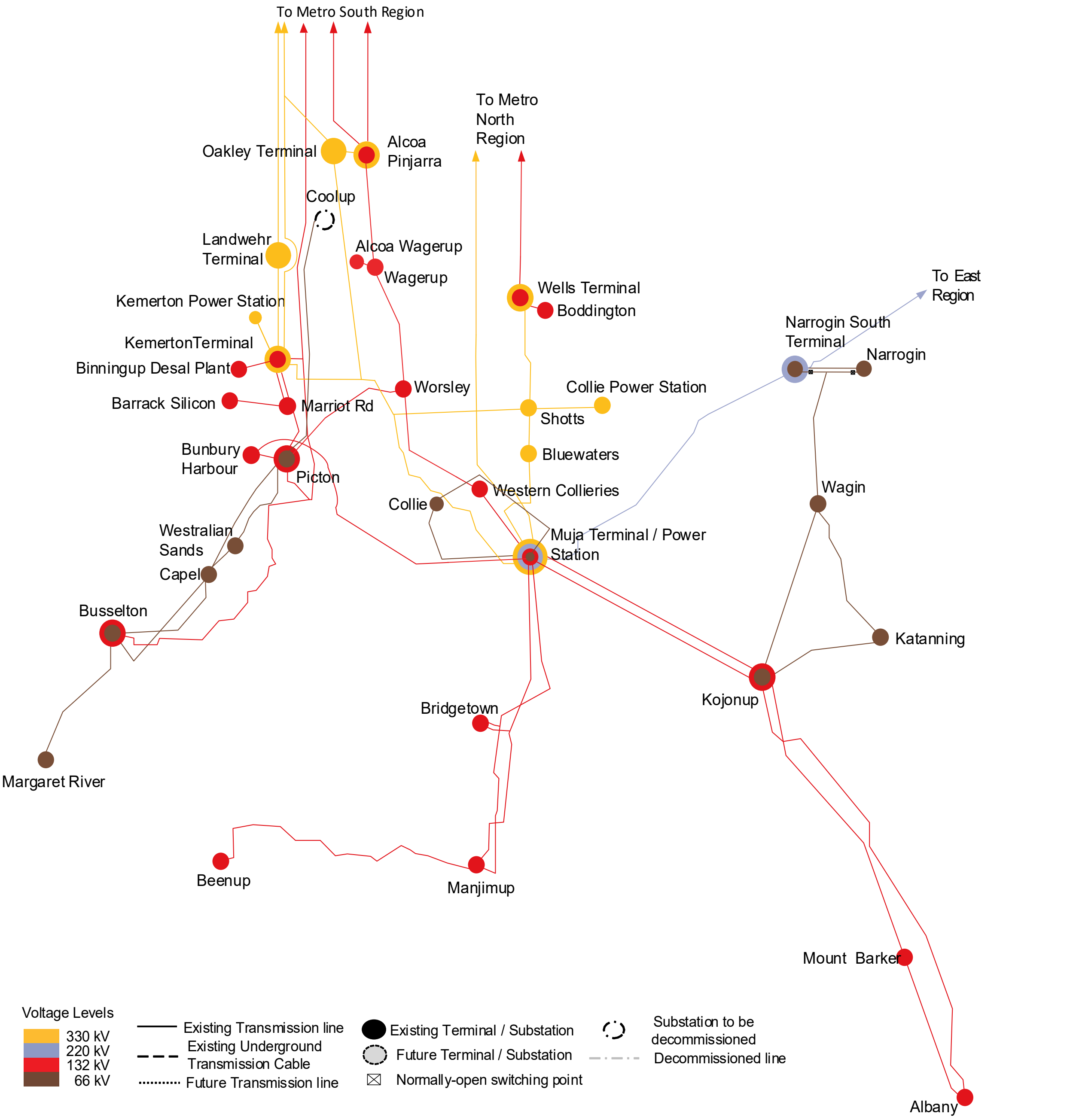

Figure 25: Western Power's South Region – Network Diagram

The South Region has 10 terminal stations and 17 zone substations that are owned and operated by Western Power. The other transmission sites in the region are customer owned substations.

Terminal substations

- Bluewater Terminal – 330 kV
- Kemerton Terminal – 330/132 kV
- Kojonup Terminal – 132/66/22 kV
- Landwehr Terminal – 330 kV
- Muja Terminal – 330/220/132/66 kV
- Narrogin South Terminal – 220/66 kV
- Oakley Terminal – 330 kV
- Picton Terminal – 132/66/22 kV
- Shotts Terminal – 330 kV
- Wells Terminal – 330/132 kV

Zone Substations / WP Substations

- Albany – 132/22 kV
- Beenup – 132/22 kV
- Bridgetown – 132/22 kV
- Bunbury Harbour – 132/22 kV
- Busselton – 132/66/22 kV
- Capel – 66/22 kV
- Collie – 66/22 kV
- Coolup – 66/22 kV
- Katanning – 66/22 kV
- Kojonup – 132/66/22 kV
- Margaret River – 66/22 kV
- Marriott Road – 132/22 kV
- Mount Barker – 132/22 kV
- Manjimup – 132/22 kV
- Narrogin – 220/66/22 kV
- Wagerup – 132/22 kV
- Wagin – 66/22 kV

Customer Substations

- Alcoa Pinjarra – 132 kV
- Alcoa Wagerup – 132 kV
- Blue Waters PS – 330 kV
- Boddington – 132/22 kV
- Western Collieries – 132 kV
- Westralian Sands – 66 kV

11.2 Regional Characteristics

11.2.1 General

The South Region is comprised of residential, industrial and farming loads. It is also a generation hub of conventional (mostly coal-fired) generation.

Due to the extensive geographical spread of the South Region, its substations supply peak demands at different periods in a year. The substations supplying mostly residential loads are winter peaking, while majority of the substations supplying predominantly agricultural loads have a summer peak pattern.

Underpinned by tourism, coastal lifestyle seekers and industrial and mining developments, the growing concentration of urban development in Bunbury and Busselton has seen similar pressures placed on the South Region system as in the Perth metropolitan area, where the penetration of air conditioning has had a significant impact on forecast demand.

11.2.2 Generation

The generation portfolio in this region is predominately coal. Most of the coal-fired generation is concentrated at Muja and Collie, about 200km south of Perth. Synergy currently owns and operates both power stations, which have an aggregate capacity of approximately 1,200 MW.

On 14 June 2022, the State Government announced plans to progressively retire all remaining State-owned coal-fired power stations by 2030. These exits will leave only one coal-fired power plant operating in WA – the privately-owned Bluewaters generator, which is also near Collie.

The retirement of coal-fired generation in the South Region represents a fundamental change. It is likely to significantly impact the ability to maintain adequate voltage control and performance, both within the region and in the wider SWIS, as well as reducing overall system inertia and strength.

The Bunbury and Picton South area is supplied by local generation at Kemerton and relies heavily on generation from the Muja area. Apart from coal-fired generation, the South Region consists of wind power generation mainly concentrated around Albany.

11.2.3 Existing Transmission Network Supply

The South Region has a mix of 330 kV, 220 kV, 132 kV and 66 kV transmission voltages with relatively long transmission lines compared to most of other regions. The region has a strong 330 kV network including long transmission lines from the Muja and Kemerton terminal substations. There is also a single 220 kV transmission line from the Muja terminal that supplies the Narrogin South terminal and continues to the Eastern Goldfields, as well as several 132 kV sub-transmission systems connecting to the Picton, Bunbury and Busselton substations.

Given the availability of fuel resources, particularly coal, the area has historically been home to the bulk of base load generating capacity via the bulk 330 kV transmission network. The security and reliability of the network surrounding the Muja Terminal is paramount because of the reliance of neighbouring regions on the generation capacity connected to it. The area itself is divided into a number of independent sub-networks supplying load connected via 132 kV and 66 kV transmission lines. A significant portion of the 66 kV transmission network was built to a 132 kV standard, which presents opportunities to either convert it to 132 kV or retire the network as these assets reach the end of their service life.

The bulk of supply to support demand in the region south of Kemerton comes from the Muja and Kemerton terminals via several 132 kV transmission lines. Power is transferred to the Kemerton terminal at 330 kV from the Muja terminal, as well as from other 330 kV terminals.

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 which interconnects Picton, Kemerton, Pinjarra and Busselton and the ageing and voltage constrained 66 kV transmission network that extends from Picton as far south as Margaret River.

11.2.4 Key Developments In the Region

Key developments in the South Region have been focused on the increasing challenges associated within operating base load generation, due to the overwhelming uptake in residential rooftop solar. In response to these challenges, the State Government has announced the progressive retirement of Collie and Muja coal-fired generation by 2030. Refer to section to 2.2.2 for more detail.

11.3 Performance

This section presents the network performance for the South Region over the study period.

11.3.1 Thermal Capacity - Boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and security constrained and economic dispatch conditions.
- Export boundaries consider peak demand and maximum generation dispatch conditions (within boundary) .

Import Boundaries

Figure 26 shows the network import boundaries in the South Region. These boundaries are defined using the worst contingency () and the worst overload circuit (*) as shown in Table 9.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 27 to Figure 30.

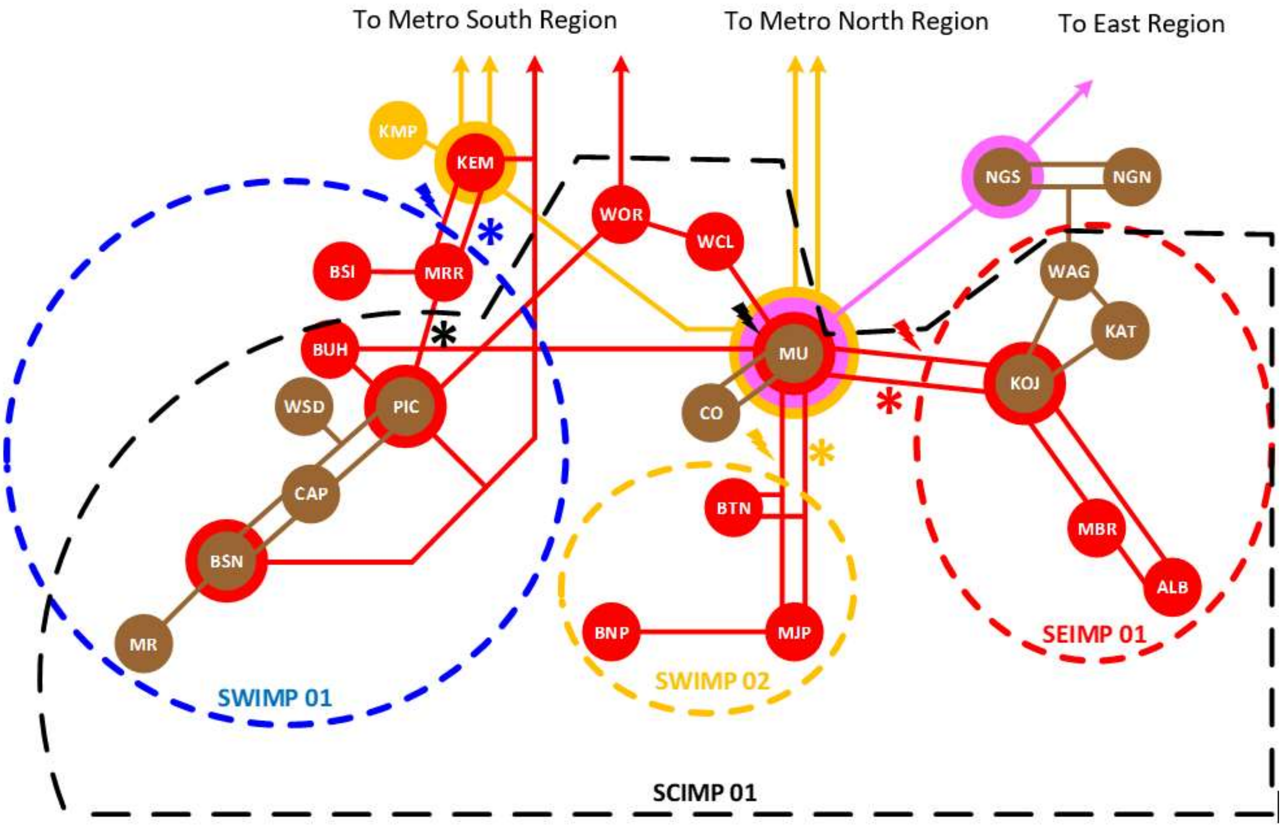

Figure 26: Network import boundaries in the South Region

Table 9: Thermal import boundaries characteristics – South Region

Characteristics	Import Boundaries			
	SWIMP 01	SWIMP 02	SEIMP 01	SCIMP 01
Worst contingency	Kemerton – Marriot Road 81 or Kemerton – Marriot Road 82	Muja-Manjimup/ Bridgetown 81 or Muja-Manjimup/Bridgetown 82	Muja – Kojonup 82	Muja BTT1 and BTT2
Contingency type	N-1	N-1	N-1	N-1-1
Worst overload circuit	Kemerton – Marriot Road 82 or Kemerton – Marriot Road 81	Manjimup/ Bridgetown 82 or Manjimup/ Bridgetown 81	Muja – Kojonup 81	Picton-Marriot Road 81

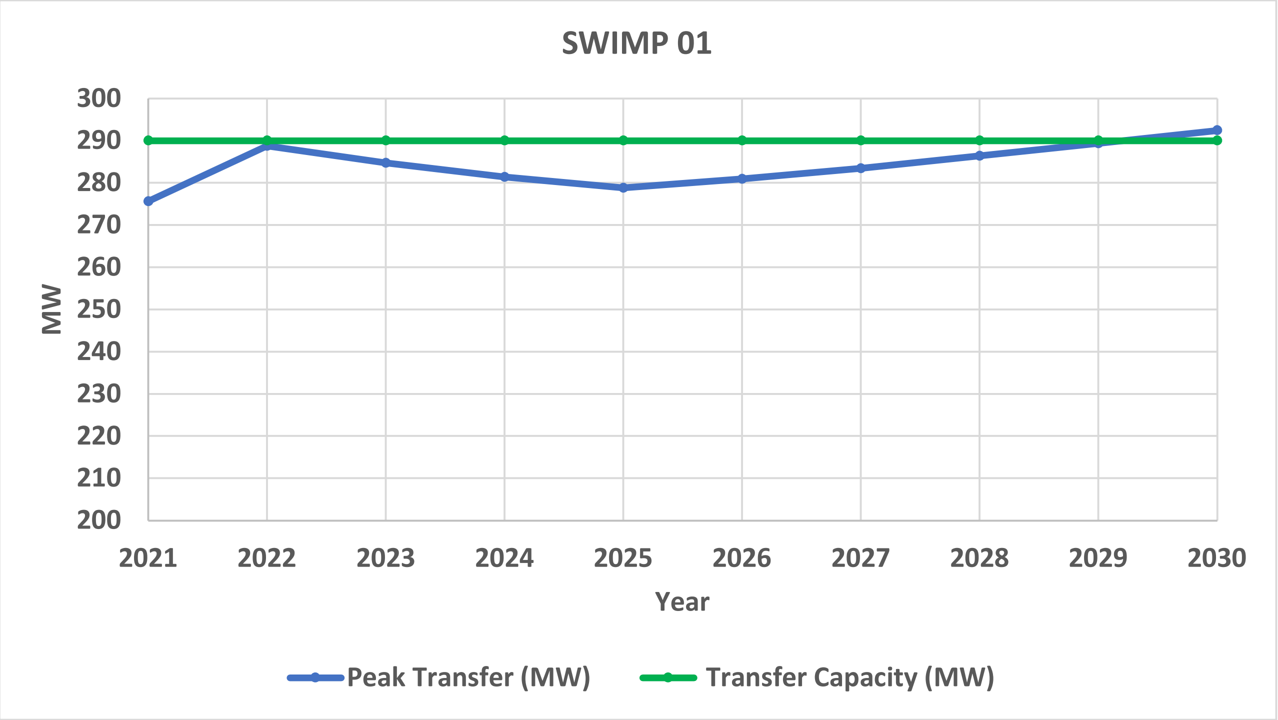

Figure 27: Expected transfer and transfer capacity in SWIMP 01 boundary – peak demand

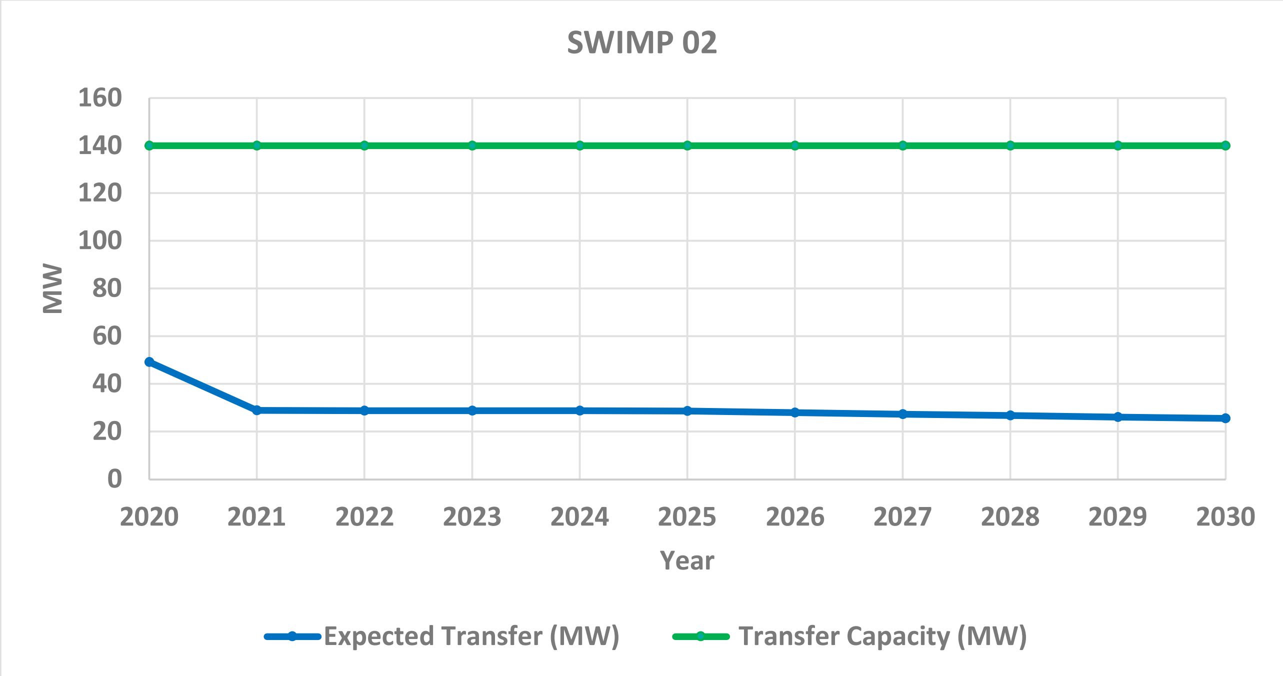

Figure 28: Expected transfer and transfer capacity in SWIMP 02 boundary – peak demand

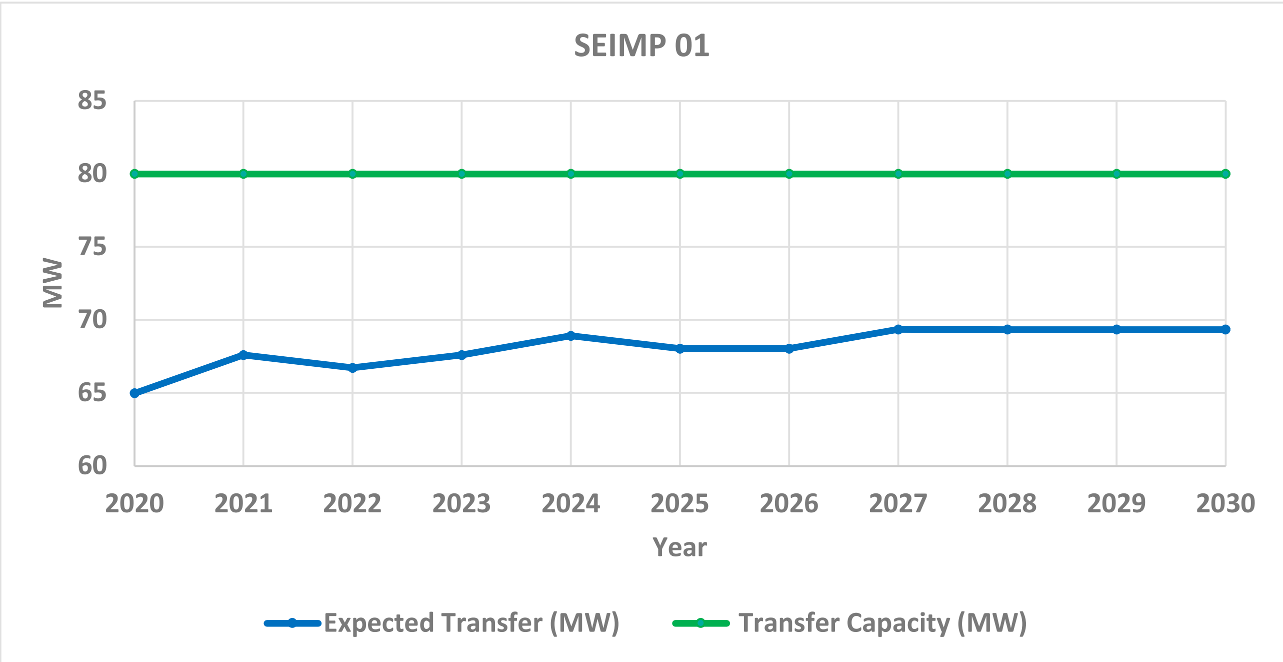

Figure 29: Expected transfer and transfer capacity in SEIMP 01 boundary – peak demand

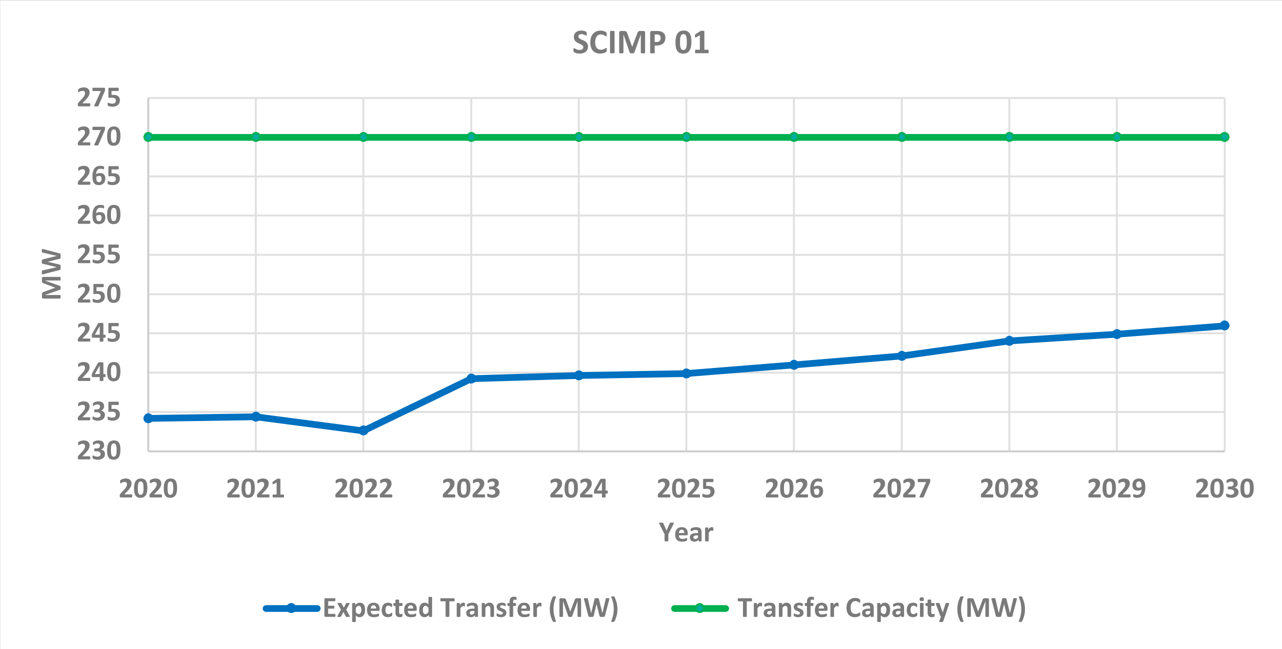

Figure 30: Expected transfer and transfer capacity in SCIMP 01 boundary – peak demand

As observed in the above figures, the available import capacity in SWIMP 01 is very limited and is expected to be exceeded at the end of the study period.

The available import capacity in SWIMP 02 is expected to be sufficient throughout the study period, whereas the connection of new loads within the SCIMP 01 and SEIMP 01 boundaries will be limited without network augmentation.

Export Boundaries

Figure 31 shows the network import boundaries in the South Region. These boundaries are defined using the worst contingency (⚡) and the worst overload circuit (*) as shown in Table 10.

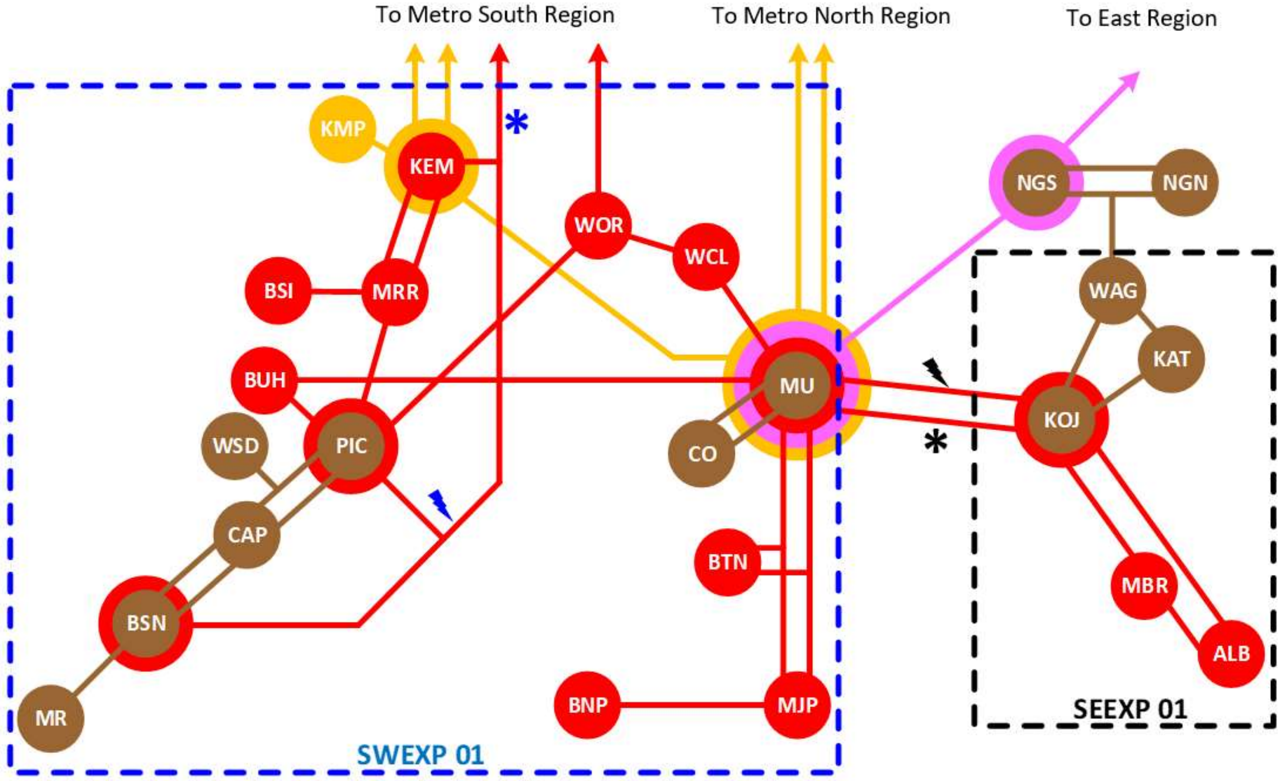

Figure 31: Network export boundaries in the South Region

Table 10: Thermal export boundaries characteristics – South Region

Characteristics	Export Boundaries	
	SWEXP 01	SEEXP 01
Worst contingency	Picton-Busselton 81	Muja-Kojonup 82
Contingency type	N-1	N-1
Worst overload circuit	Pinjarra-Alcoa Pinjarra 81	Muja-Kojonup 81

The expected transfer and transfer capacity for each of the import boundaries across the study period is shown in Figure 32 and Figure 33.

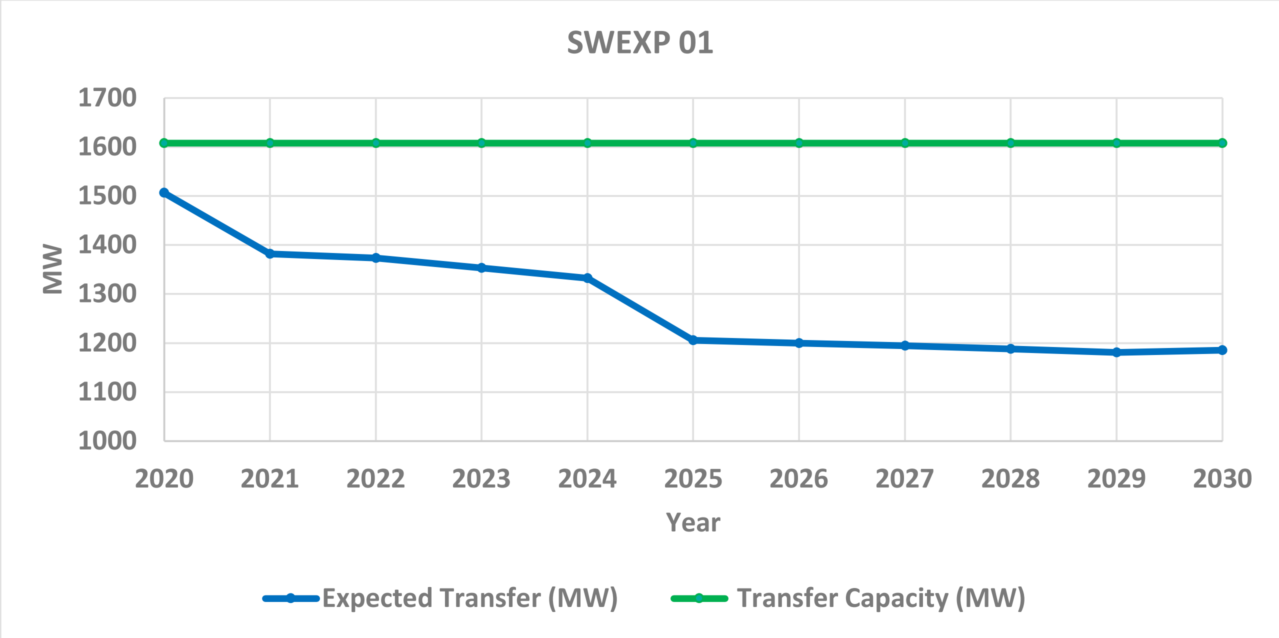

Figure 32: Expected transfer and transfer capacity in SWEXP 01 boundary – peak demand

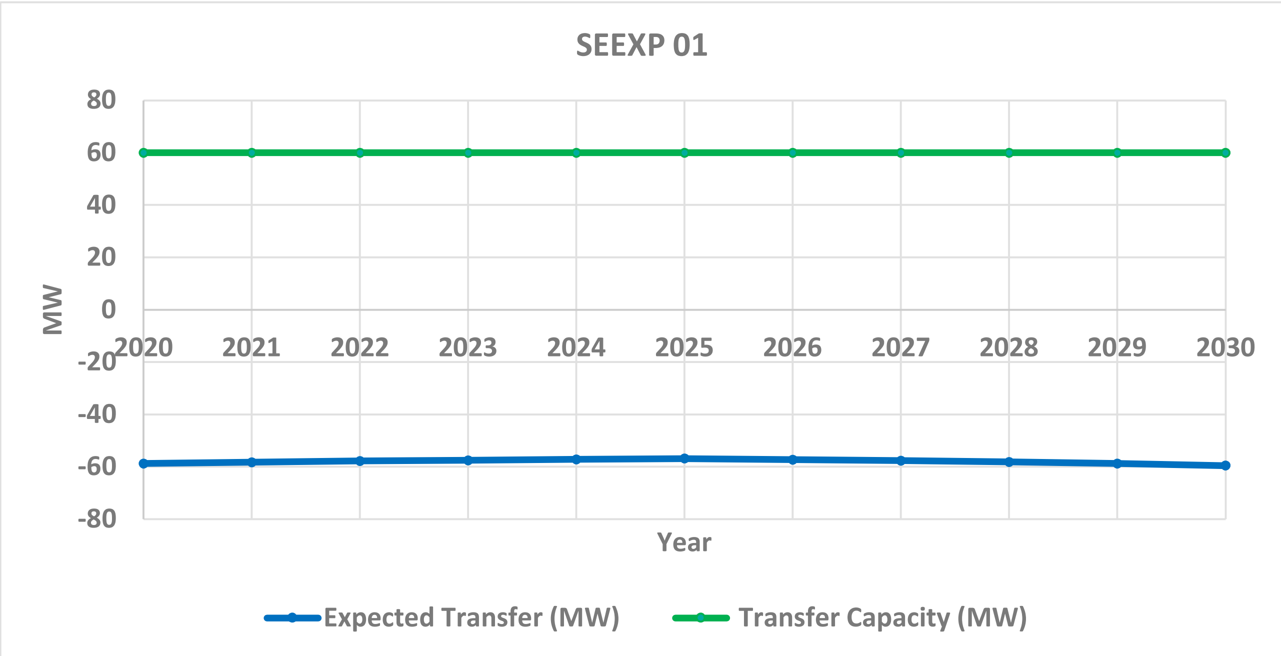

Figure 33: Expected transfer and export transfer capacity in SEEXP 01 boundary – peak demand

Over the study period, available export capacity within the SWEXP 01 boundary increases due to the planned retirement of the Muja G5 and G6 units by 2024, making it a suitable candidate to support new generation connections on the under-utilised 330 kV network. The expected transfers for the SEEXP 01 boundary remain a net importer of power during high generation and peak demand conditions, presenting opportunities for new generation connections at 132 kV.

11.3.2 Thermal Constraints - Transmission Lines

Post contingent thermal performance constraints arise within the South Region during peak conditions on the following circuits:

- Pinjarra to Alcoa Pinjarra 132 kV line overloads occur by 22/23 and increases up to 103 per cent, following the loss of the four-ended Picton to Busselton 132 kV circuit.

11.3.3 Thermal Capacity – Transformers

Terminal Transformers

Existing post contingent thermal overloads arise within the South Region over the study period during peak conditions on the following bulk terminal transformers:

- Kemerton Quad Boost T1 Transformer overloads occur by 21/22 and increases up to 125 per cent, following the loss of the Kemerton T2 transformer.

Zone Substation Transformers

This section shows the existing and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the South Region.

Table 11: Utilisation legend (for Table 12)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

Table 12: South Region Zone Substation utilisation heat map

	Sub Capacity	Actual Utilisation (%)	Forecast Utilisation (%)																				Comments
Substation	Current MVA	2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
			POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	POE10	POE50	
Albany	60	91	90	84	90	84	89	83	88	83	88	82	87	82	87	81	86	81	86	81	85	80	
Beenup	14	48	49	42	50	41	50	41	50	40	50	40	50	39	50	39	50	38	50	38	49	37	
Boddington	10	55	55	41	55	41	55	41	56	40	56	40	56	40	56	40	56	40	56	40	56	39	
Busselton	71	71	72	67	73	67	74	68	75	69	76	70	77	71	78	72	79	73	80	74	81	75	
Bridgetown	29	99	104	90	104	90	104	90	105	91	105	91	105	91	106	92	106	92	107	92	107	93	Managed by distribution transfers
Bunbury Harbour	62	107	106	97	106	96	106	95	106	94	106	93	107	92	107	92	108	91	108	90	109	89	Managed by distribution transfers
Capel	43	46	58	48	58	48	65	54	65	54	65	54	65	54	65	54	65	54	65	54	65	54	Transformer Replacement (Scoping, RIS year 2027)
Coolup	12	65	65	36	65	36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Coolup load transferred to Wagerup (2022) to facilitate substation decommissioning.
Collie	30	53	53	48	53	48	52	47	52	46	52	46	51	45	51	45	51	44	51	44	51	43	
Katanning	20	75	76	73	76	73	76	73	76	73	76	73	76	74	76	74	76	74	76	74	76	74	
Kojonup	10	27	27	25	27	25	27	25	27	25	27	25	27	25	28	25	28	25	28	25	28	25	
Mount Barker	44	18	17	16	17	15	16	15	16	14	15	14	15	13	14	12	14	12	13	11	13	11	
Manjimup	29	50	49	46	48	45	47	44	46	43	45	42	44	41	43	41	42	40	42	39	41	38	

westernpower

Margaret River	37	47	47	45	47	45	47	45	47	45	47	46	48	46	48	46	48	47	49	47	49	47	
Marriot Road	67	61	112	103	112	104	113	104	113	104	113	104	113	104	113	104	114	105	114	105	114	105	A portion of non-reference customers have curtailable load such that the substation does not exceed capacity.
Narrogin	40	39	39	38	40	38	40	38	41	37	41	37	42	36	43	36	43	35	44	35	45	34	
Picton	74	64	65	58	66	58	67	59	68	59	69	60	70	60	71	61	72	61	73	61	74	62	
Wagin	6	90	89	84	88	83	87	83	86	82	86	82	85	81	85	81	84	81	84	80	83	80	
Wagerup	30	49	49	36	49	36	66	54	66	54	66	54	65	54	65	54	65	54	65	54	64	54	Load transfer from CLP (Execution, RIS year 2022)

11.3.4 Steady State Voltages

A number of existing voltage-related performance constraints arise within the South Region during peak demand conditions over the study period, including:

- Low voltages (0.67pu) and excessive voltage step conditions (-10.5 per cent) by 2020/21 at the Busselton 66 kV, Busselton 132 kV and Margaret River 66 kV busbars, following the loss of the four-ended Picton to Busselton 132 kV line.
- Low voltages (0.86pu) by 2020/21 at the Capel 66 kV busbar, following the loss of the four-ended Picton to Busselton 132 kV line.
- Low voltages (between 0.7 pu to 0.9 pu) and excessive voltage step conditions (-22.4 per cent) by 2020/21 at the Katanning, Wagin, Narrogin and Narrogin South 66 kV busbars, following the loss of the Kojonup to Katanning 66 kV line.
- Low voltages (below 0.7pu) by 2020/21 at the Boddington and Wells Terminal 132 kV busbar, following the loss of the Shotts to Wells Terminal 330 kV line.

A number of voltage-related performance constraints arise within the South Region during minimum demand conditions over the study period, including:

- High voltages (1.11pu) by 2021/22 at the Busselton 132 kV busbars, following the loss of the four-ended Picton to Busselton 132 kV line.
- Low voltages (between 0.70pu - 0.88pu) and low voltage step conditions (between -13.7 per cent to -15.7 per cent) arise by 2021/22 at the Boddington and Wells Terminal 132 kV busbars and Wells Terminal 330 kV busbars, following the loss of the Shotts to Wells Terminal 330 kV line[34].
- High voltages (marginally above 1.10pu) by 2028/29 at the Kemerton Terminal, Oakley Terminal, Shotts Terminal, Landwehr Terminal, Muja Terminal, and Wells Terminal 330 kV busbars, following the loss of either generators at Bluewaters Power Station.

In addition, the Busselton Zone Substation transformers are reaching their minimum transformer tap position during daytime minimum demand conditions, losing the ability to control pre- and post-contingent voltages within network performance limits on the downstream 22 kV distribution networks.

11.3.5 Fault Levels

There are no fault level-related performance constraints within the South Region over the study period.

11.3.6 Stability

Similar to the North and East Regions, growing levels of inverter-based generation in the region have triggered the need to conduct system strength studies for all existing facilities in the South Region. The N-0 study results observed that all facilities are expected to retain control loop stability.

Though existing N-0 studies have not revealed any system strength limitations, given the limited number of synchronous generators in parts of the network Western Power expects that system strength issues will materialise under certain contingency conditions. Solutions to these issues could include retuning of the control parameters of a facility, installation of stabilising equipment (e.g., BESS, STATCOM, synchronous condensers) or operational constraints.

[34] These risks are currently managed through an existing under voltage load shedding scheme that sheds load at Boddington to maintain system security.

Further work is ongoing to refine the EMT models and undertake system studies for contingency conditions in the South Region.

11.3.7 Reliability

There are no reliability-related performance constraints within the South Region over the study period.

11.3.8 Asset

Existing asset performance constraints have been identified in the South Region within the study period, including:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
    - Wagin – 66/22 kV 5 MVA – T1 & T3
    - Katanning – 66/22 kV 6 MVA – T1, T2 & T3
    - Kojonup – 132/66 KV 20 MVA – T2
    - Boddington – 132/22 kV 13 MVA -T3
    - Albany – 132/22 kV 27 MVA -T1 & T3
    - Beenup – 132/22 kV 27 MVA - T3
    - Marriot – 132/22 kV 27 MVA - T3
    - Picton – 132/66/22 kV 100 MVA - T1 & T2
    - Narrogin South– 220/66 kV 27 MVA - T1
    - Kemerton– 132/132 kV 225 MVA Quad Booster – T1

11.4 Network Augmentation Works

Committed, completed and proposed transmission projects in the South Region are shown in Table 13 .

Table 13: Completed, committed and proposed projects – South Region

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Western Mining Substation: Busbar extension	Extension of 132 kV busbar at the Western Mining Substation	Upgrade works to facilitate a load increase for an existing customer.	Customer driven	2021/22	Completed
Marriot Road Substation: New transformer	Installation of a third 132/22 kV 33 MVA transformers at Marriot Road Substation	To facilitate an interim non-reference supply arrangement for a new customer connection.	Customer driven	2021/22	Completed
Capel Substation: Transformer replacement	The installation of a new voltage reconfigurable 132-66/22 kV 33 MVA, while maintaining the degraded T1 & T3 66 kV Capel transformers.	The first stage of a staged transformer replacement plan at Capel to address asset condition issues.	Asset Condition	2021/22	Completed

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Kemerton Terminal: New transformer	A new 330/132 kV 490 MVA transformer is installed at Kemerton terminal Substation	Address the degraded condition of the Kemerton Quad Booster. A third terminal transformer will also address an existing post-contingent thermal constraint and enable the connection of new loads in the area.	Asset Condition/ Growth - Thermal	2023/24	Execution
Coolup Substation - Decommissioning	Decommissioning of the 66 kV Coolup Substation and supplies and load transfers to Wagerup	Address degraded asset condition of the 66 kV Coolup Substation and supply lines.	Growth - Thermal	2025/26	Execution
Picton Substation: Transformer Replacement	Replace the existing 66/22 kV 27 MVA T3 transformer with a 132/22 kV 33 MVA transformer	Address degraded asset condition and accommodate increasing demand.	Asset Condition	2022/23	Execution
Wagerup Substation: Transformer Replacement	Replace existing T1 transformer with a new 132/22 kV 3 3MVA transformer	Address degraded asset condition	Asset Condition	2023/24	Execution
Wagin Substation: Transformer replacement	A staged replacement of both 66/22 kV transformers (T1 & T3).	Address degraded asset condition.	Asset Condition	2023/24	Planning
Katanning Substation: Transformer Replacement	Replacement of existing 3 x 66/22 kV transformers with a single larger voltage reconfigurable 132-66/22 kV 33 MVA transformer.	Address degraded asset condition and accommodate increasing demand.	Asset Condition	2025/26	Initiation
Picton South Transmission Reinforcement – Stage 1	Uprate the existing Picton-Capel 71 circuit to 132 kV and resupply the Westralian Sands Substation on the adjacent 66 kV Picton-Capel circuit.	Stage 1 works to facilitate the future 132 kV voltage conversion of the network between Picton and Busselton.	Asset Condition/ Growth - Voltage	2026/27	Initiation
Busselton Substation: Transformer Replacement	Replace existing 66/22 kV transformers (T1 & T3) with a third 132/22 kV 33MVA transformer	Address degraded asset condition and accommodate increasing demand. Mitigate overvoltage issues in the Busselton and Margaret River substations during minimum demand conditions.	Asset Condition /Growth - Thermal	2025/26	Planning
Busselton Substation: Install reactive support	Install of 5 MVAr 22 kV reactors at Busselton Substation	Mitigate the risk of over-voltages in the Busselton 22 kV distribution network during minimum demand conditions.	Growth - Voltage	2025/26	Planning
Capel Substation: Transformer Replacement	Replacement of existing 66/22 kV transformers (T1 & T3) with a single larger voltage reconfigurable 132-66/22 kV 33 MVA transformer.	Address the degraded condition of the asset and accommodate increasing demand	Asset Condition / Growth - Thermal	2026/27	Initiation
Picton South Transmission Reinforcement – Stage 2	Voltage conversion upgrades of the existing 66 kV supplies to 132 kV between Capel and Busselton, along with a series of 66 kV decommissioning works	Address the degraded condition with the Picton 132/66 kV transformers and increase the power transfer capability in the Picton South area to accommodate increasing demand and new customer connections.	Asset Condition/ Growth - Voltage	2026/27	Initiation
CAG[35] 99:	Line uprate works on the Kemerton and Picton 132 kV circuit	Alleviate the network supply constraints to facilitate the conversion of an interim non-reference connection to a full reference service	Customer driven	2023/24	Planning

35 Competing Applications Group

11.5 Network Opportunities

This section highlights the network opportunities in the South Region over the study period.

Table 14: Network Opportunities projects – South Region

Project	Scope	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Busselton Substation – Install reactive support	Installation of new 5 MVAr 22 kV reactors at Busselton	Increase demand in the Busselton and Margaret River area during daytime minimum demand conditions to minimises the risk of post-contingent over-voltages.	2025/26	Planning	~0.8
Picton South Transmission Reinforcement – Stage 1 & 2	A staged 132 kV voltage conversion of the existing 66 kV supplies between Picton-Capel-Busselton.	Reduce the demand supplied in the Picton South area during peak demand conditions to potentially reduce or defer network augmentation to increase the power transfer capacity to the area.	2026/27	Initiation	45-50[36]
SW IMP 02 and SC IMP 01 available import capacity	Spare available import capacity exists over a number of import boundaries within the South Region.	An opportunity exists to utilise spare available capacity within SW IMP 02 and SC IMP 01 import boundaries by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a
SW EXP 01 and SE EXP 01 available import capacity	Spare available export capacity exists over a number of export boundaries within the South Region.	An opportunity exists to utilise spare available capacity within the SW EXP 01 and SE EXP 01 export boundaries by connecting new generation.	Across the study period	n/a	n/a

11.6 Emerging Issues and Drivers

Despite several existing constraints on the 132 kV networks, the 330 kV network in the region is expected to be increasingly under-utilised. There is sufficient capacity to support large new loads and generation connections at this voltage level.

The progressive retirement of coal-fired generation at Muja and Collie is expected to create significant challenges in the area, particularly as these units are critical in providing voltage control within and external to the region and contribute a significant portion of system inertia and strength which will be lost upon their retirement. Along with the recent announced plans, Western Power is expected to work with industry and AEMO to identify system and network constraints and develop prudent and timely network development options to facilitate these retirements.

Several 66 kV networks (i.e., Muja to Collie, Kojonup to Katanning to Narrogin) within the South Region will either be retired or upgraded to 132 kV as they approach their end of service life. Several long 132 kV circuits (i.e., Picton-Worsley 81 & Muja-Bunbury Harbour 81) are also approaching their end of service life within the next 10 to 20 years. Western Power is investigating several replacement options, including the potential to de-mesh parts of the South Region to simplify power flows within and out of the region.

[36] This represents the estimated cost for the line upgrade works between Picton and Busselton.

12 East Region

12.1 Geography

The East Region covers the network east of (and including) Sawyers Valley, through to Kondinin, Kalgoorlie and the Goldfields. Figure 34 shows the transmission system in the region.

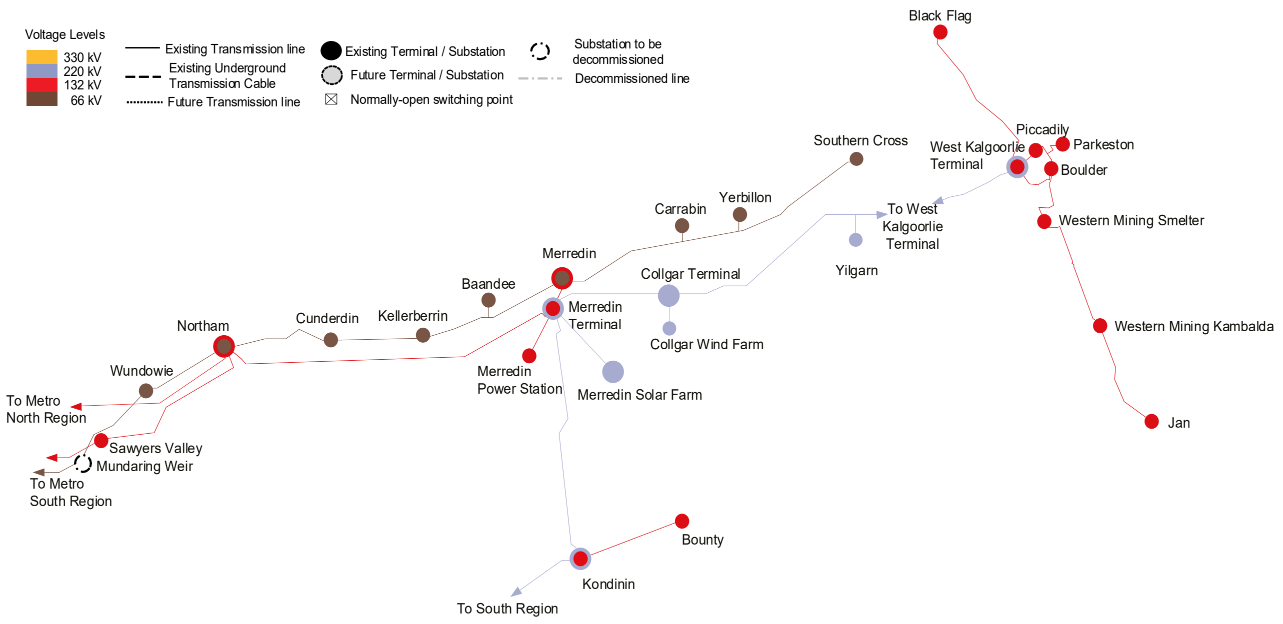

Figure 34: Western Power's East Region – Network Diagram

The East Region features six terminals and 19 zone substations that are owned and operated by Western Power. The other transmission sites in East Region are customer-owned substations.

Terminals:

- Collgar – 220 kV (Customer)
- Kondinin – 220 kV
- Merredin – 220/132/22 kV
- Northam – 132/66 kV
- West Kalgoorlie – 220/132 kV
- Yilgarn – 220/33/22 kV

Zone Substations / WP Substations

- Black Flag – 132/33 kV
- Boulder – 132/33 kV
- Bounty – 132/33 kV
- Carrabin – 66/22 kV
- Cunderdin – 132/33 kV
- Kellerberrin – 66/22 kV
- Kondinin – 220/33 kV
- Mundaring Weir – 66/6.6 kV
- Merredin – 132/22 kV
- Mundaring Weir – 66 kV[37]
- Northam – 66/22 kV
- Piccadilly – 132/11 kV
- Sawyers Valley – 132/22 kV
- Southern Cross – 66/33 kV
- West Kalgoorlie – 132/11 kV
- West Kalgoorlie – 132/33 kV

[37] The Mundaring Weir 66kV substation is still energised but the load has been transferred to Sawyers Valley substation

- Wundowie – 66/22 kV
- Yerbillon – 66/0.44 kV
- Yilgarn – 220/33 kV

Customer substations

- Baandee – 66 kV
- Edna May Operations – 66 kV
- Jan – 132 kV
- Merredin Power Station – 132 kV
- Parkeston – 132 kV
- Western Mining Kambalda – 132 kV
- Western Mining Smelter – 132 kV

12.2 Regional Characteristics

12.2.1 General

There is a combination of residential and mining loads in the East Region. Substations from Sawyers Valley through to Kalgoorlie are a mixture of low density residential and agricultural loads. The customers south of Southern Cross (to the east) through to the Goldfields are predominately high-density mining, industrial and agricultural load.

The demand in this region is heavily sensitive to commodity prices. This makes planning difficult, with new connections typically being block loads to connect new mining loads, which makes them difficult to forecast due to their inherent volatility in response to market economics. Considerable uncertainty in demand forecasts in turn creates difficulties when evaluating the need to commit to transmission system augmentation.

12.2.2 Generation

There is more than 750 MW of generation throughout the East Region, including a significant amount of gas-fired generation installed in the Goldfields that is owned and operated by independent power producers servicing the mining sector. There is also a mixture of solar and wind generation within the region and during some operating conditions where renewable generation output is high, it can be a net exporter of power.

12.2.3 Existing Transmission Network Supply

The East Region is predominantly supplied via the 220 kV line from Muja and the 132 kV networks connected to the Metro North Region, via the Northern and Guildford terminals. A large sub-transmission 66 kV network also extends from Cannington Terminal (in the Metro South Region) through to Southern Cross Substation towards the Goldfields.

The 220 kV line from Muja to West Kalgoorlie Terminal (via Kondinin and Merredin Terminal) is more than 650 km long. This circuit provides supply to Kalgoorlie and the Goldfields and is been designed to an N-0 standard. Under system normal conditions, the 66 kV line between Cunderdin and Kellerberrin is out of service to maintain system security.

Due to the relatively low capital cost of installing protection and control schemes compared to traditional network reinforcement options in Kalgoorlie and the Goldfields, many protection and control schemes have been installed in recent years. The purpose of these schemes includes providing new customers with non-reference services through runback schemes and fast tripping protection schemes that island customers or isolate parts of the network.

12.2.4 Key Developments In the Region

New load connections in the region have historically been challenging due to network limitations that arise on 220 kV supply when assessing connections under unconstrained basis. Western Power has recently adopted a more flexible approach when assessing customers and has offered non-reference solutions to customers looking to connect to the network.

Due to the demand for non-reference services in the region, Western Power has developed the Eastern Goldfields Load Permissive Scheme (ELPS). This scheme is used to signal capacity in operational real-time to several non-reference customers. Should the 220 kV line reach critical pre-contingent levels, non-reference customer loads are curtailed to maintain system security.

Due to aging Static VAR compensators in the East Region, Western Power has upgraded the SVCs with more modern STATCOM technology across several sites within the Goldfields area, including Boulder, Piccadilly and Western Kalgoorlie. These STATCOM devices provide fast-acting reactive power control to the region and together with a third 220/132 kV 250 MVA transformer at West Kalgoorlie Terminal, increased the power transfer capacity in the area to accommodate increases in demand in the area.

12.3 Network Performance

This section presents the network performance for the East Region over the study period.

12.3.1 Thermal Capacity – Boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and security constrained and economic dispatch conditions
- Export boundaries consider peak demand and maximum generation dispatch conditions (within boundary)

Import Boundaries

Figure 35 shows the most active network import boundaries in the East Region. These boundaries are defined using the worst contingency ( ) and the worst overload circuit (*) as given in Table 15.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 36 to Figure 38.

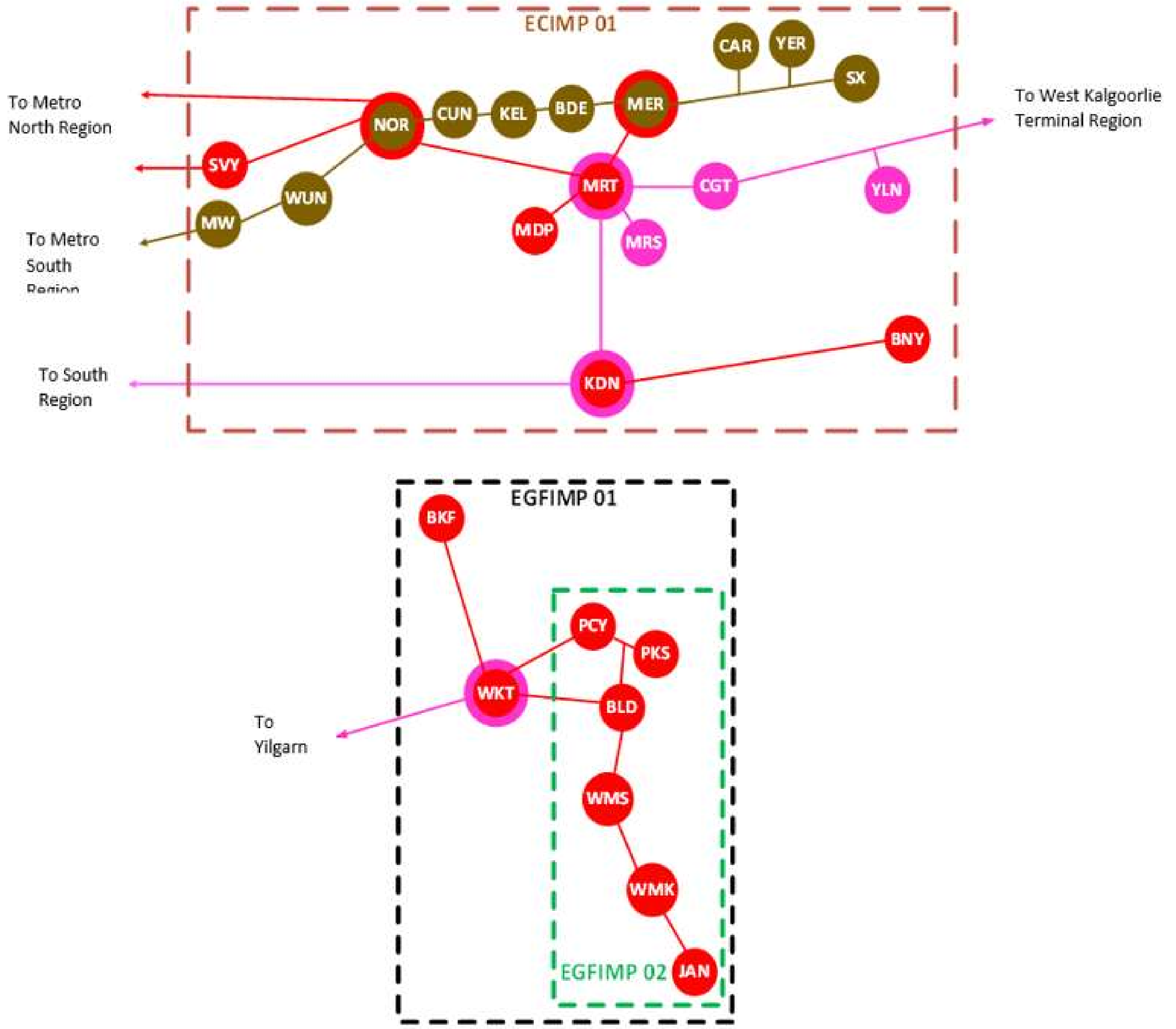

Figure 35: Network import boundaries in the East Region

Table 15: Thermal import boundaries characteristics – East Region

Characteristics	Import Boundaries		
	ECIMP 01	EGFIMP 01	EGFIMP 02
Worst contingency	Darlington-Sawyers Valley 81	West Kalgoorlie Tx	West Kalgoorlie-Piccadilly 81
Contingency type	N-1	N-1	N-1
Worst circuit/s	Northern Terminal-Northam 81	West Kalgoorlie Tx	West Kalgoorlie – Boulder 81

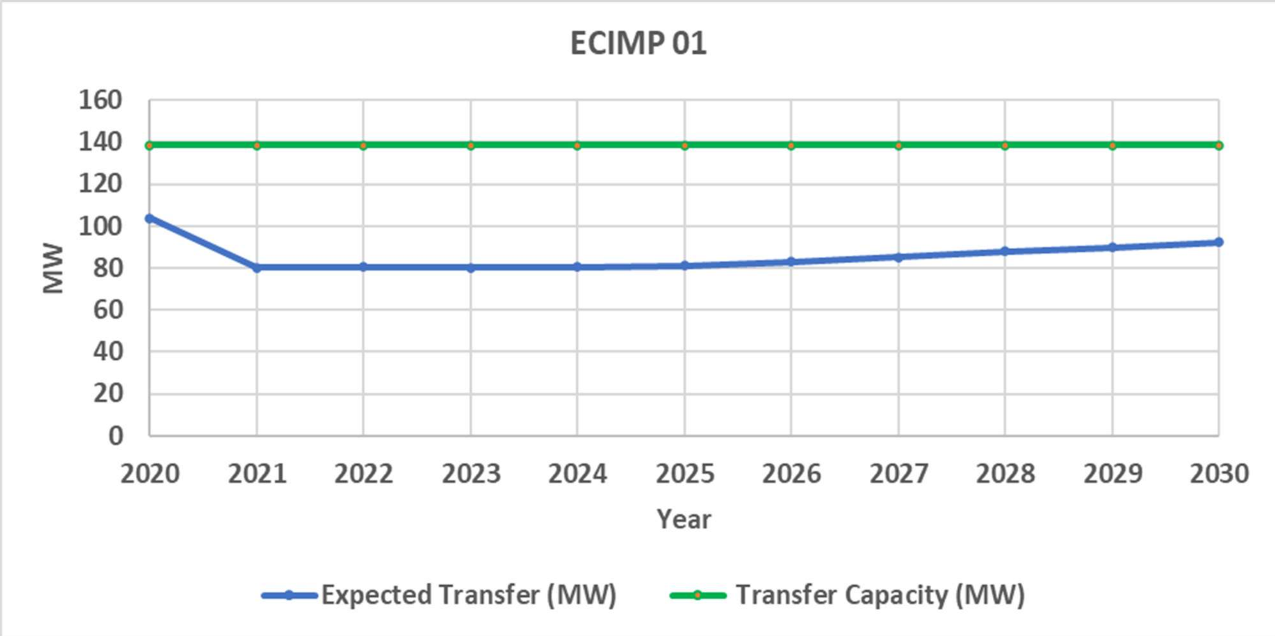

Figure 36: Expected transfer and transfer capacity in ECIMP 01 boundary – peak demand

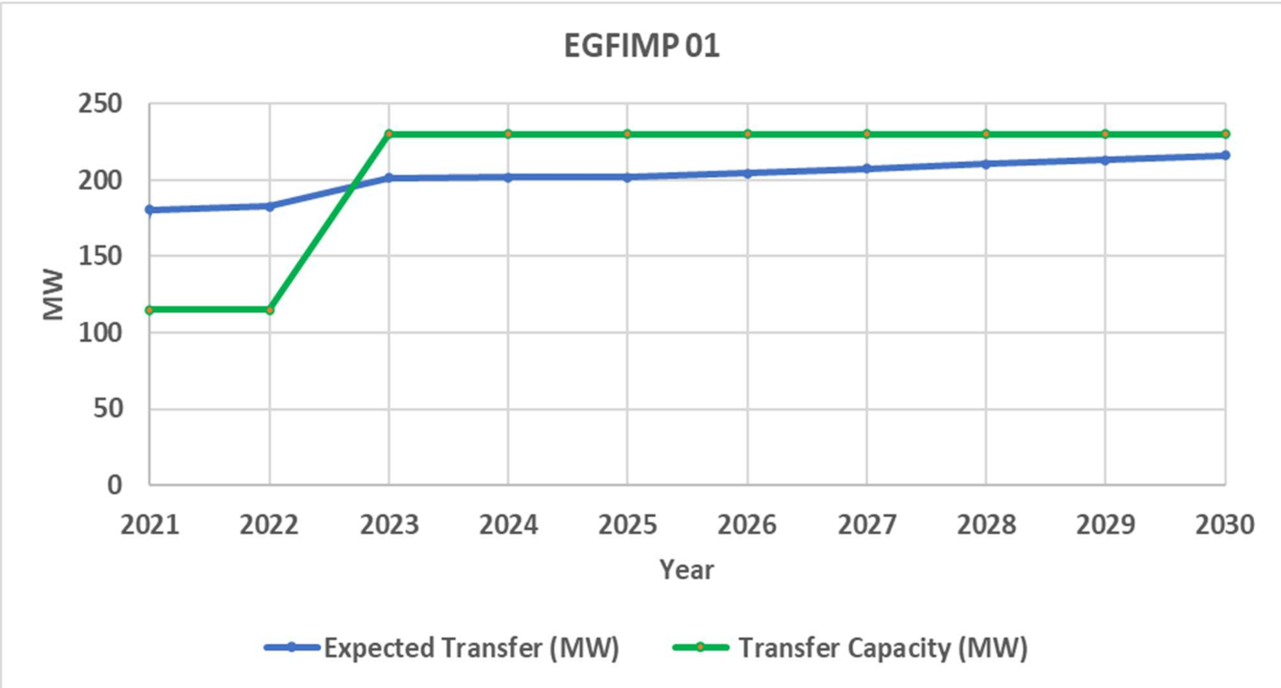

Figure 37: Expected transfer and transfer capacity in EGFIMP 01 boundary – peak demand

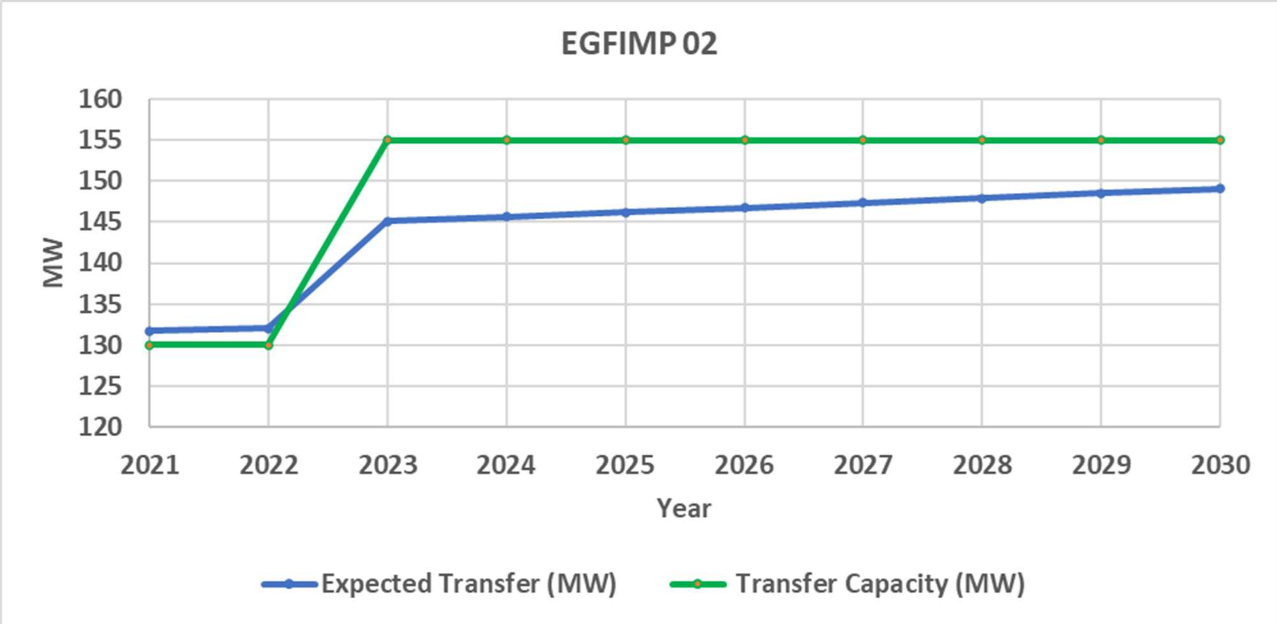

Figure 38: Expected transfer and import capacity in EGFIMP 02 boundary – peak demand

ECIMP 01 has enough capacity to accommodate between approximately 40 MW and 60 MW over the ten-year study period.

At the start of the study period, the expected transfers into the both the EGFIMP 01 and EGFIMP 02 import boundaries were above the transfer capacity however existing runback schemes pre-contingently curtail non-reference loads in the area to manage these potential overload risks. The expected transfers into the EGFIMP 01 boundary are much higher during this period, as the majority of the non-reference loads are supplied from the Boulder and West Kalgoorlie substations.

Network augmentation to install a third terminal transformer at West Kalgoorlie and replace the degraded SVC increased power transfer capacities from 2023, with limited capacity to connect new load connections in the remaining years of the study period.

Export Boundaries

Figure 39 shows the most active network import boundaries in the East Region. These boundaries are defined using the worst contingency (⚡) and the worst overload circuit (*) as given in Table 16.

The expected transfer and transfer capacity for each of the export boundaries across the study period are shown in Figure 40 and Figure 41.

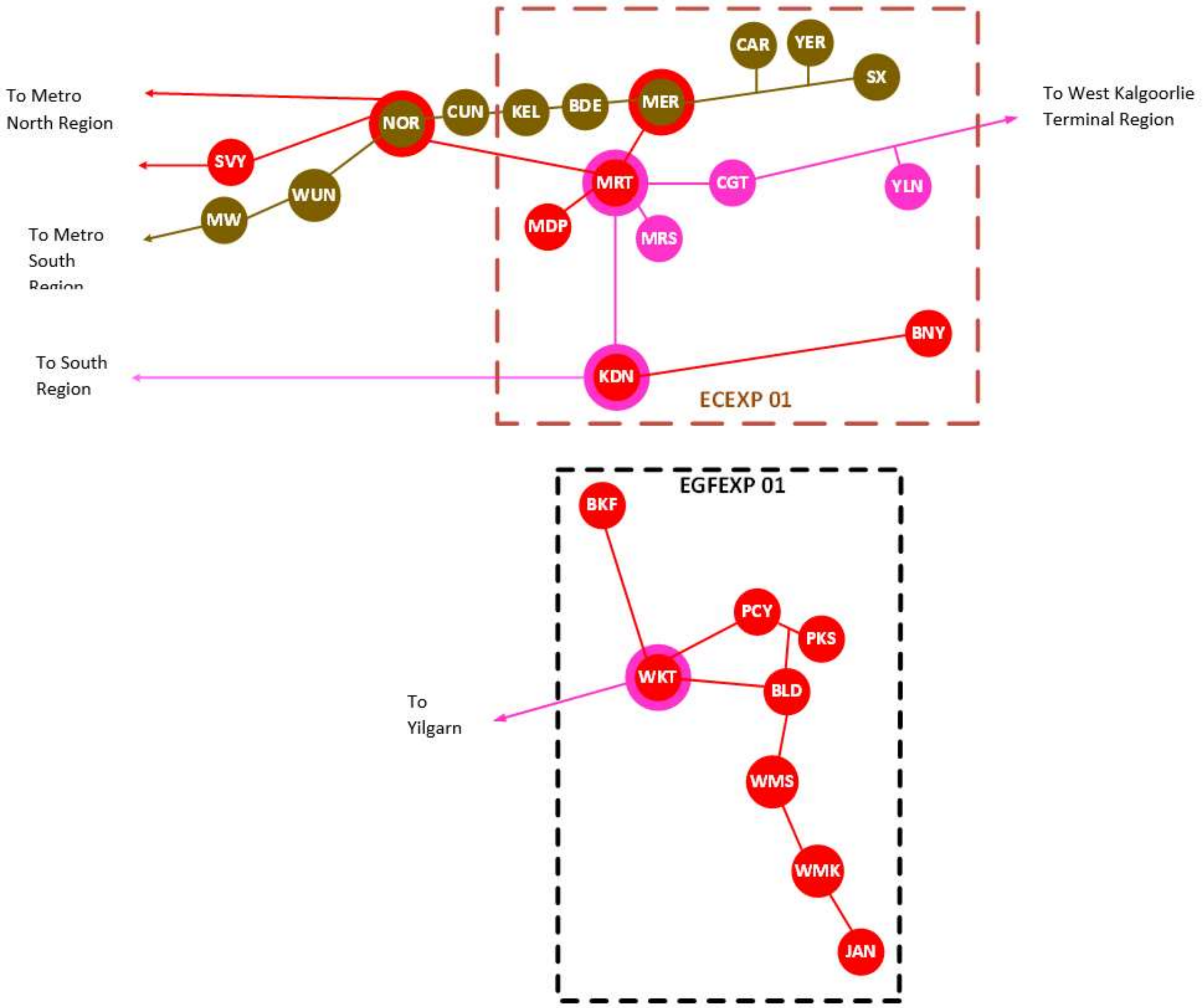

Figure 39: Network import boundaries in the East Region

Table 16: Thermal export boundaries characteristics – East Region

Characteristics	Export Boundaries	
	ECEXP 01	EGFEXP 01
Worst contingency	n/a	West Kalgoorlie Tx
Contingency type	N-0	N-1
Worst circuit/s	Merredin Terminal – Northam 81	West Kalgoorlie Tx

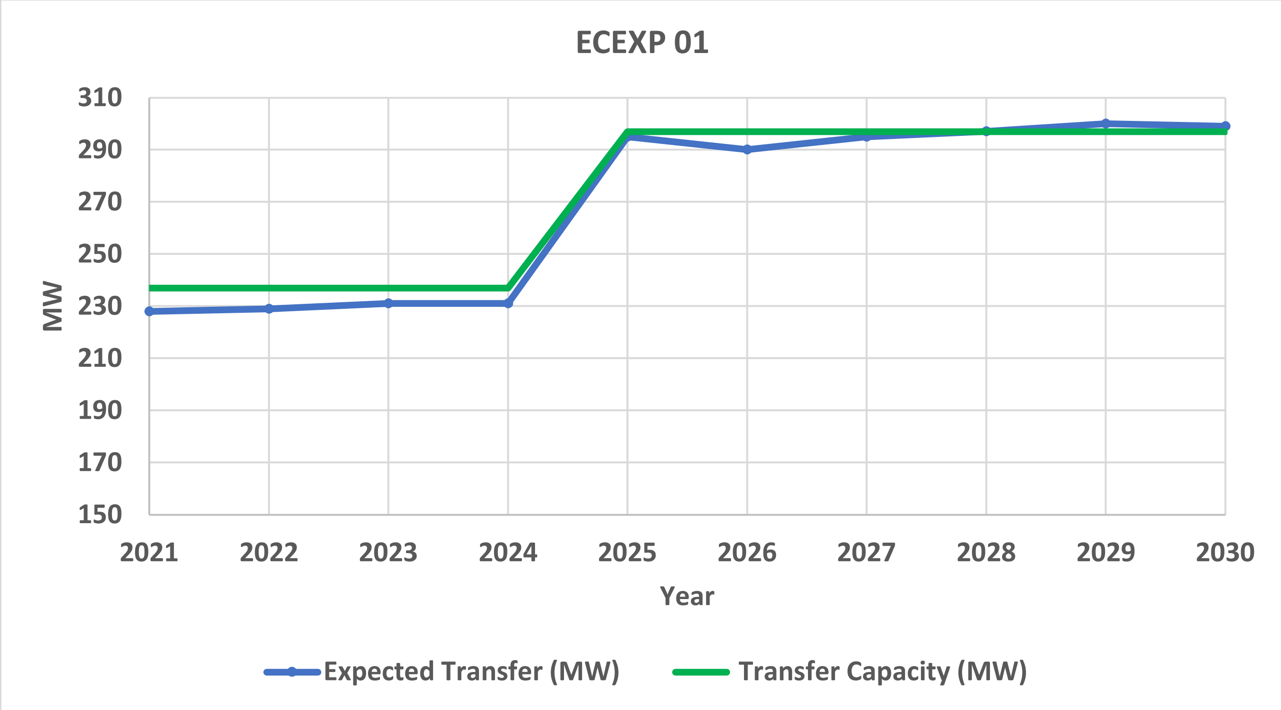

Figure 40: Expected transfer and transfer capacity in ECEXP 01 boundary – peak demand

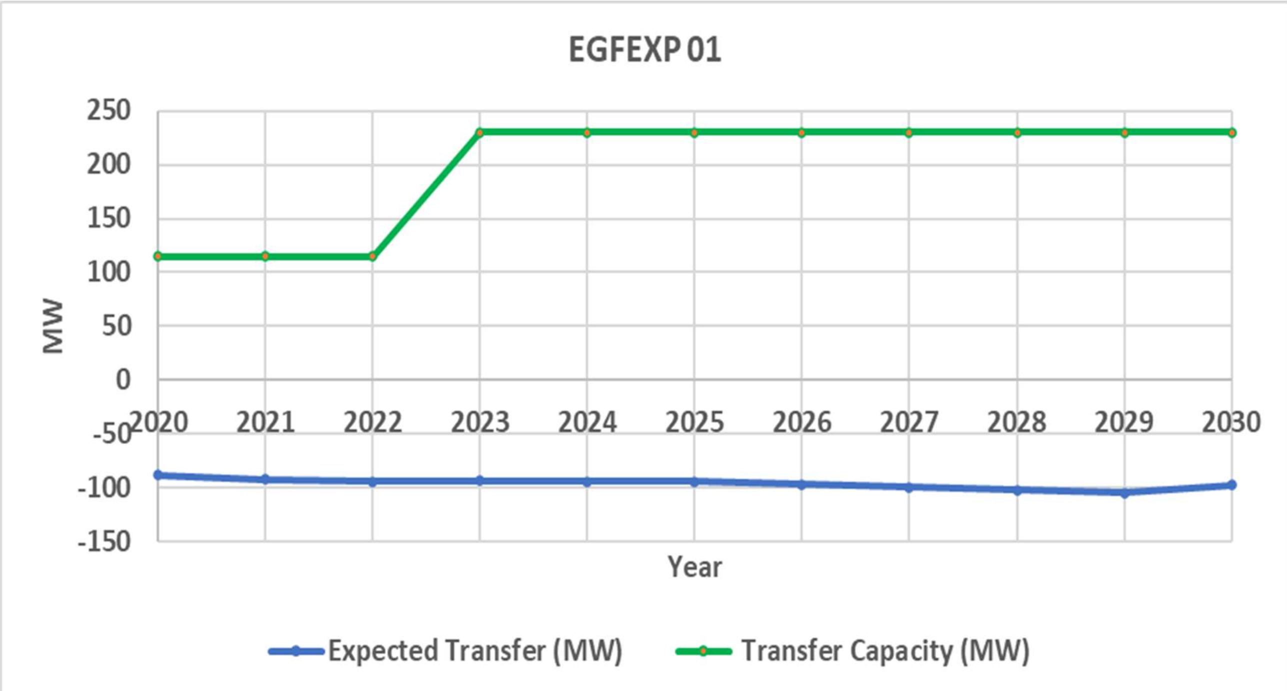

Figure 41: Expected transfer and export capacity in EGFEXP 01 boundary – peak demand

The EC EXP 01 export boundary is limited pre-contingently because of high renewable generation output in the area. An existing post-contingent runback scheme manages transfer levels across the Northern Terminal to Merredin 132 kV circuit by curtailing the output of the Collgar wind farm. Additional generation in the region that contributes to this constraint will also require a similar runback scheme.

Although the EGF EXP 01 export boundaries have sufficient available thermal export capacity throughout the study period, it is important to note that stability constraints in this boundary are likely to bind before thermal constraints, reducing the available capacity shown in Figure 41. Western Power is working to develop simplified ways to represent stability constraints that can arise due to multiple factors, making it more difficult to represent than thermal constraints.

12.3.2 Thermal Capacity – Transmission Lines

No thermal overloads arise within the East Region over the study period.

12.3.3 Thermal Capacity – Transformers

This section shows the existing and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the South Region.

Table 17: Utilisation legend (for Table 18)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

Table 18: East Region Zone Substation utilisation heat map[38]

Substation	Sub Capacity	Actual Utilisation (%)	Forecast Utilisation (%)																				Comment
	MVA	2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
	Current		PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	
Black Flag	31	118	142	105	140	127	139	127	139	127	139	127	139	127	139	128	139	128	139	129	139	129	A portion of non-reference customers have curtailable load such that the substation does not exceed capacity.
Boulder	62	47	45	40	44	38	44	38	45	38	46	39	46	39	47	40	48	40	50	41	50	41	
Bounty	10	102	114	100	114	100	114	100	114	100	113	100	113	100	113	100	113	100	113	100	113	100	10 MVA loading TR compliance limit
Carrabin	6	20	17	15	17	15	17	15	17	15	18	15	18	15	18	15	18	16	18	16	18	16	
Cunderdin	14	64	64	59	64	59	64	59	65	59	65	59	66	60	66	60	67	61	68	61	68	61	
Kellerberrin	6	54	53	50	53	51	53	52	52	53	52	54	52	55	52	56	52	57	52	59	52	60	
Kondinin	29	33	35	32	35	32	35	32	35	31	35	31	35	31	35	31	34	30	34	30	34	30	
Merredin	13	85	88	79	89	80	91	80	92	81	93	81	95	82	96	83	97	83	98	84	100	85	
Northam	41	66	67	65	66	65	66	64	66	64	66	64	66	64	65	63	65	63	65	63	66	64	
Piccadilly	64	61	58	51	58	51	59	51	60	51	60	51	61	51	62	51	63	51	64	51	64	51	
Sawyers Valley	56	45	45	37	46	37	47	37	48	37	69	56	70	56	71	56	72	57	73	57	75	57	
Southern Cross	13	20	20	16	19	16	19	16	19	16	19	16	19	16	19	16	19	16	19	16	19	16	
West Kalgoorlie 11 kV	31	43	43	36	44	37	45	37	46	37	47	37	49	38	50	38	51	38	52	39	53	39	

38 Baandee substation uses estimated data due to insufficient real-time demand measurements, which have been reviewed as inaccurate. As a result, they have been removed.

West Kalgoorlie 33 kV	30	46	74	58	120	104	120	104	119	104	119	103	119	103	119	103	119	103	119	103	119	103	New distribution block load in 2022. A portion of non-reference customers have curtailable load that ensures the substation does not exceed its capacity.
Wundowie	16	67	68	64	68	64	68	64	67	64	67	63	0	0	0	0	0	0	0	0	0	0	
Yerbillon	5	54	67	58	75	67	82	73	88	79	93	85	99	91	105	97	111	103	117	109	123	114	
Yilgarn	29	43	56	44	56	44	56	44	56	44	56	44	55	44	55	43	55	43	54	43	54	43	

12.3.4 Steady State Voltages

There are no voltage-related performance constraints within the East Region over the study period.

12.3.5 Fault Levels

There are no fault rating-related performance constraints within the East Region over the study period.

12.3.6 Stability

The long length and relatively high impedance of the 220 kV Muja to West Kalgoorlie, presents operational challenges in terms of system stability. Transient limitations are by the relatively low inertia of generating units and the transient voltage instability limits that arise due to insufficient reactive reserve. Special protection schemes and Network Control Services (NCS) are in place to manage these limitations.

Oscillatory stability issues (small signal) have also been identified between machines in the area and other SWIS generating units. The capacitive and inductive impedance configuration of the 220 kV system can, under certain conditions, give rise to sub-harmonic oscillations. Western Power installed a dynamic power system-monitoring tool (Psymetrix) that enables better identification of oscillatory stability related issues in the area to improve network security.

Similar to the North and South Regions, growing levels of inverter-based generation in the East Region have triggered the need to conduct system strength studies for all existing facilities. The N-0 study results observed that all facilities are expected to retain control loop stability.

Though the existing N-0 studies have not revealed any system strength limitations, given the limited number of synchronous generators in parts of the network Western Power expects that system strength issues will materialise under certain contingency conditions. Solutions to these issues could include retuning of the control parameters of a facility, installation of stabilising equipment (e.g., BESS, STATCOM, synchronous condensers) or operational constraints.

Further work is ongoing to refine the EMT models and to undertake system studies for contingency conditions in the East Region.

12.3.7 Reliability

Due to a single connection to the rest of the network via a 220 kV circuit, supplies to Kalgoorlie and the Goldfields are operated to a N-0 supply standard, presenting a reduced level of security. Provisions in the Technical Rules envisage supply to Boulder, Kalgoorlie and Coolgardie town load to have N-1 reliability. In 2018, amendments to the NQRS Code were made to enable reliability of supply during planned outages of the network equipment. This reliability is currently provided under an NCS arrangement, with historical and future performance shown in Figure 42.

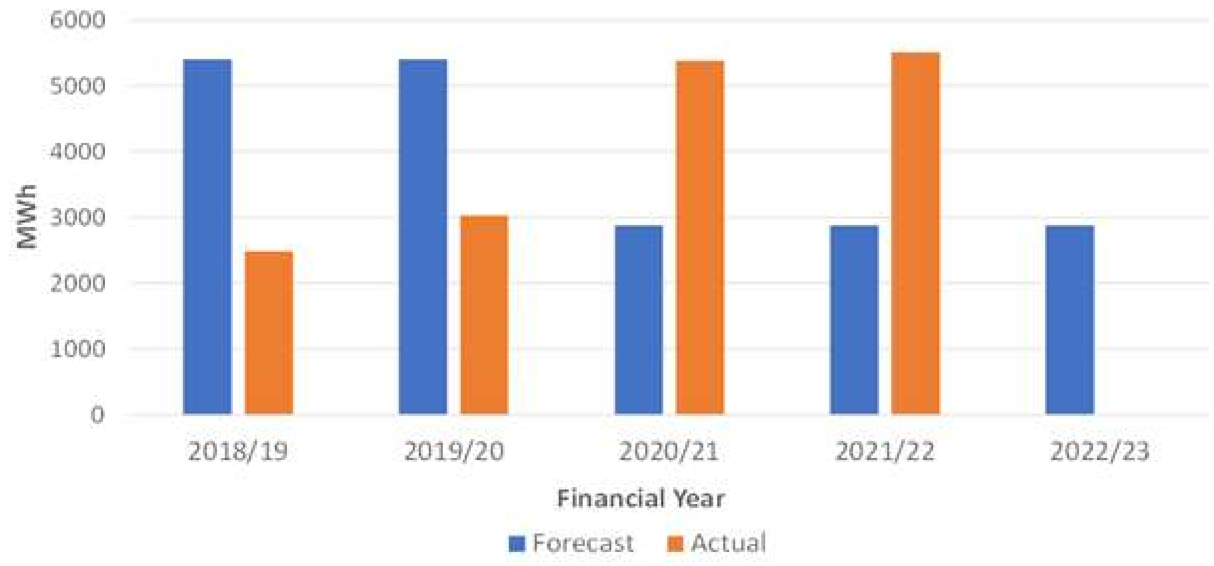

Figure 42: NCS operation in the East Region

12.3.8 Asset

Existing asset performance constraints were identified in the East Region within the study period, including:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
    - Northam – 66/22 kV 15 MVA – T1, T2 and T3
    - Southern Cross – 66/33 kV 12 MVA – T1 and T2
    - Merredin – 66/22 kV 13 MVA – T2
    - Cunderdin – 66/22 kV 15MVA – T2
    - Northam – 132/66 kV 37.5 MVA – T1 and T2
    - Kondinin – 220/33 kV 27 MVA Auto-Transformer T1
    - Black Flag – 132/33 kV 27 MVA – T2 and T3
    - Boulder – 132/33 kV 27 MVA – T1, T2 and T3
    - Bounty – 132/33 kV 27 MVA – T1
    - West Kalgoorlie – 132/33 kV 27 MVA – T5
    - Yilgarn – 220/33 kV 27 MVA – T2
- The 11 kV switchboards at Piccadilly are in degraded condition and need to be addressed in the next 10 years.

12.4 Network Augmentation Works

Committed, completed and proposed transmission projects in the East Region are shown in Table 19.

Table 19: Completed, committed and proposed projects – East Region

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Western Kalgoorlie Terminal: Replace SVC	Replace West Kalgoorlie SVC with newer technology STATCOM units at West Kalgoorlie, Boulder and Piccadilly substations	Address degraded asset condition	Asset Condition	2021/22	Completed
Western Kalgoorlie Terminal: New Transformer	Install a third 220/132 kV 250 MVA transformer at Western Kalgoorlie Terminal	Additional transformer capacity to accommodate increasing demand in the area.	Growth – Thermal	2021/22	Completed
Merredin Terminal: Refurbish SVC	Refurbish existing SVC units at Merredin termina.	Address degraded asset condition	Asset Condition	2021/22	Completed
Black Flag Substation: Transformer Upgrade & Intertrip scheme	Transformer upgrades to the existing T2 and T3 transformers. In addition, the installation of an intertrip scheme for connecting non-reference customers	Increase the Black Flag Substation capacity to accommodate increased demand in the area and new block loads under a non-reference service supply arrangement	Customer Driven	2021/22	Completed
Northam Substation: Transformer Upgrade	Remove the existing 3 x 66 kV transformers and install one 132/22 kV 33 MVA unit	Address degraded asset condition	Asset Condition	2023/24	Execution
Cunderdin Substation: Solar Farm generation connection	Install of a new cut in-out 132 kV substation to the Northam-Merredin terminal 81 circuit	Facilitate the connection of a new 100 MW solar farm.	Customer Driven	2023/24	Planning
Wundowie Substation: Decommissioning	Decommissioning of the 66 kV substation assets, including distribution load transfers to Sawyers Valley substation.	Address degraded asset condition	Asset condition	2026/27	Scoping
Mundaring Weir Substation: Decommissioning	The 66 kV Mundaring Weir Zone Substation is already de-energised. This works involves decommissioning and removing the degraded substation assets.	Decommission and remove the degraded and redundant 66 kV substation assets	Asset condition	2028/29	Scoping
Black Flag Substation: New Transformer	Installation of a new 66 MVA 132/33 kV transformer at Black Flag Substation.	Increase the Black Flag Substation capacity to accommodate increased demand in the area. Existing customers with a non-reference service may have the opportunity to convert a reference service.	Asset Condition	2026/27	Scoping
Eastern Goldfields NCS contract	A NCS contract to call upon standby generation in the East Region upon the loss of the single 220 kV circuit.	Improve the level of reliability service provided to customers in Kalgoorlie-Boulder city and Coolgardie town loads, following the loss of the single 220 kV circuit.	Reliability	2023/24	Execution

12.5 Network Opportunities

This section highlights the network opportunities in the East Region over the study period.

Table 20: Network Opportunities projects – East Region

Project	Scope / Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Eastern Goldfields Load Permissive Scheme	The ELPS scheme is currently operational and provides a non-reference supply connection for a number of new loads into the Goldfields.	The ELPS can connect additional customers in the Goldfields under a non-reference arrangement.	Across the study period	NA	NA
Black Flag Substation: New Transformer	Install a new 66 MVA 132/33 kV transformer at Black Flag Substation	Additional transformer capacity will facilitate the connection of new load. Existing customers with a non-reference service may have the opportunity to convert a reference service.	Across the study period	NA	NA
Wundowie Substation: Decommissioning	Decommissioning of the 66 kV substation assets, including distribution load transfers to Sawyers Valley Substation.	To reduce demand in the area to reduce the scope of distribution load transfer works.	2023/24	Scoping	1.7
Eastern Goldfields NCS contract	A NCS contract to call upon standby generation in the East Region upon the loss of the single 220 kV circuit.	To provide standby generation under an NCS contract arrangement to improve the level of reliability of supply to these areas. These NCS contracts are up for renewing at the end of 2022/23. Over the longer-term, reduce demand in the area to eliminate, reduce of defer the need for a new 330 kV circuit from Muja to West Kalgoorlie Terminal, which will remove the need for an NCS.	2023/24	Execution (existing NCS contract) / Initiation (Renewal of NCS/network augmentation)	~1,000[39]
EC IMP 01 available import capacity	Spare available import capacity exists over a number of import boundaries within the East Region.	An opportunity exists to utilise spare available capacity within EC IMP 01 import boundaries by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a

12.6 Emerging Issues and Drivers

The long transmission supply lines throughout the East Region present significant challenges in alleviating network constraints due to high capital costs required to perform network upgrades. Additionally, most of the 66 kV assets between the Wundowie and Southern Cross substations are anticipated to be progressively retired or upgraded to 132 kV as they reach their end of service life.

In the short- to medium-term, it is anticipated that the ELPS will provide prospective load customers opportunity to connect under a non-reference service, resulting in higher utilisation of the 220 kV supply.

39 High level cost estimate to construct a new 330 kV circuit from Muja Terminal to West Kalgoorlie Terminal.

An upcoming challenge faced by the entire network is the retirement of coal-fired generation at the Muja and Collie power stations. This will have a large impact on the East Region, as the bulk of the region's power transfer comes from Muja via the single 220 kV circuit.

Over the medium- to longer term, the transition away from fossil fuel generation is expected to significantly increase demand, particularly within the Goldfields area. Furthermore, the mining industry is anticipated to decarbonise faster than other industries, which is likely to increase demand on the already constrained 220 kV single circuit supply. Western Power is currently investigating several network augmentation options to support future demand scenarios, ranging from solutions that provide incremental increases in power transfer to large-scale network augmentation that will support higher decarbonisation demand scenarios. Depending on the amount of decarbonisation, an additional circuit may be required from Muja to the Goldfields.

13 Metro North Region

13.1 Geography

The Metro North Region covers the northern extent of the Perth metropolitan area and is bound by coastal and western suburbs in the west, Malaga and North Beach in the north, and the eastern suburbs and foothills areas of Forrestfield and Darlington in the east. Figure 43 shows the transmission system in this region.

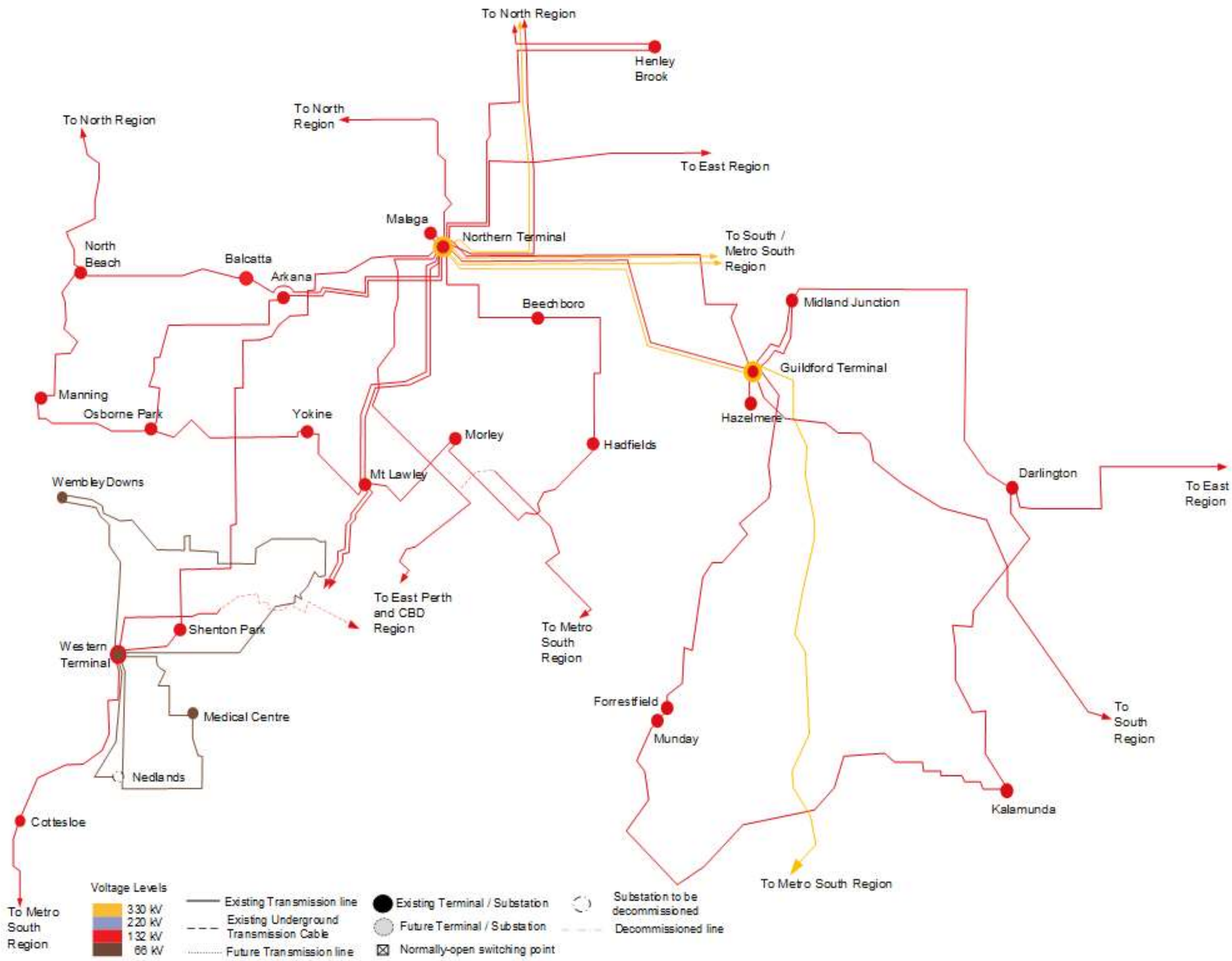

Figure 43: Western Power's Metro North Region – Network Diagram

The Metro North Region features three terminals and 23 zone substations that are owned and operated by Western Power. The other transmission sites in this region are customer owned substations.

Terminals:

- Guilford Terminal – 330/132 kV
- Northern Terminal – 330/132 kV
- Western Terminal – 132/66 kV

Zone Substations / WP Substations

- Arkana – 132/22 kV
- Beechboro – 132/22 kV
- Cottesloe – 132/11 kV
- Darlington – 132/22 kV
- Forrestfield – 132/22 kV
- Hadfield – 132/22 kV
- Hazelmere – 132/22 kV
- Henley Brook – 132/22 kV
- Kalamunda – 132/22 kV
- Malaga – 132/22 kV
- Manning Street – 132/11 kV
- Medical Centre – 66/11 kV
- Midland Junction – 132/22 kV
- Morley – 132/11 kV
- Mount Lawley – 132 kV (switchyard)
- Maida Vale – 132/25 kV
- Nedlands – 66/6.6 kV
- North Beach – 132/22 kV
- Osborne Park – 132/11 kV
- Shenton Park – 132/11 kV
- Wembley Downs – 66/11 kV
- Yokine – 132/11 kV

Customer Substations

- Munday – 132/22 kV

13.2 Regional Characteristics

13.2.1 General

The Metro North Region has a variety of loads. The area around the Western Terminal is predominantly residential, with some commercial and light industrial loads. Heavy industrial loads exist in the east near Perth Airport, along with commercial and industrial loads at Forrestfield and Midland Junction. Most supply south of the Northern Terminal is residential, with a mixture of commercial and light industrial loads. Towards the east, Darlington and Kalamunda substations consist of semi-rural connections supplying residential load.

13.2.2 Generation

There is no notable generation within the Metro North Region.

13.2.3 Existing Transmission Network Supply

The Metro North Region is a mix of 330 kV, 132 kV and 66 kV transmission voltages. The Northern Terminal is currently one of the largest load centres in the Western Power Network. The network in the area is characterised by strong 330 kV ties with generation centres in the south (from the Muja and Kwinana terminals) and north from the Neerabup Terminal, as well as 330 kV connections with large load supported by the Southern Terminal and Guildford Terminal. The network within the Northern Terminal is highly meshed, which can create considerable challenges as numerous contingencies in the area can generate power network security issues under some operating conditions.

There are three 132 kV transmission circuits connected to the Western Terminal that provide its supply, with overhead lines originating from the Northern, South Fremantle and East Perth terminals via the Cook Street Substation. Supply to substations from Western Terminal has been predominately achieved through an aging 66 kV sub-transmission network. Western Power is investigating further opportunities to consolidate and convert assets to 132 kV over the medium term, where possible.

The transmission network in around the Guildford Terminal is connected to other major terminals, including the Northern Terminal by 330 kV and 132 kV transmission circuits, and the Southern Terminal by a 330 kV circuit. There are also 132 kV circuits connecting the Guildford, Muja and Merredin terminals. The 330 kV and 132 kV bus sections within the Guildford Terminal are connected via a single 490 MVA transformer that supports most of the demand in the area. Following an outage of this transformer, these loads rely on support from the Northern Terminal and other 132 kV injections from neighbouring regions.

13.2.4 Key Developments In the Region

The most notable developments in the Metro North Region are around the rapid increase in rooftop solar PV connection, which has created increasing challenges in operation of the power system during low demand conditions. These challenges are expected to increase as new rooftop solar PV connections into the SWIS increase at a steady rate over the next five years.

13.3 Network Performance

This section presents the network performance for the Metro North Region over the study period.

13.3.1 Thermal Capacity – Boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and economic generation dispatch conditions.

Import Boundaries

Figure 44 shows the network import boundaries in the Metro North Region. These boundaries are defined using the worst contingency (↯) and the worst overload circuit (*) as shown in Table 20.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 45 to Figure 47.

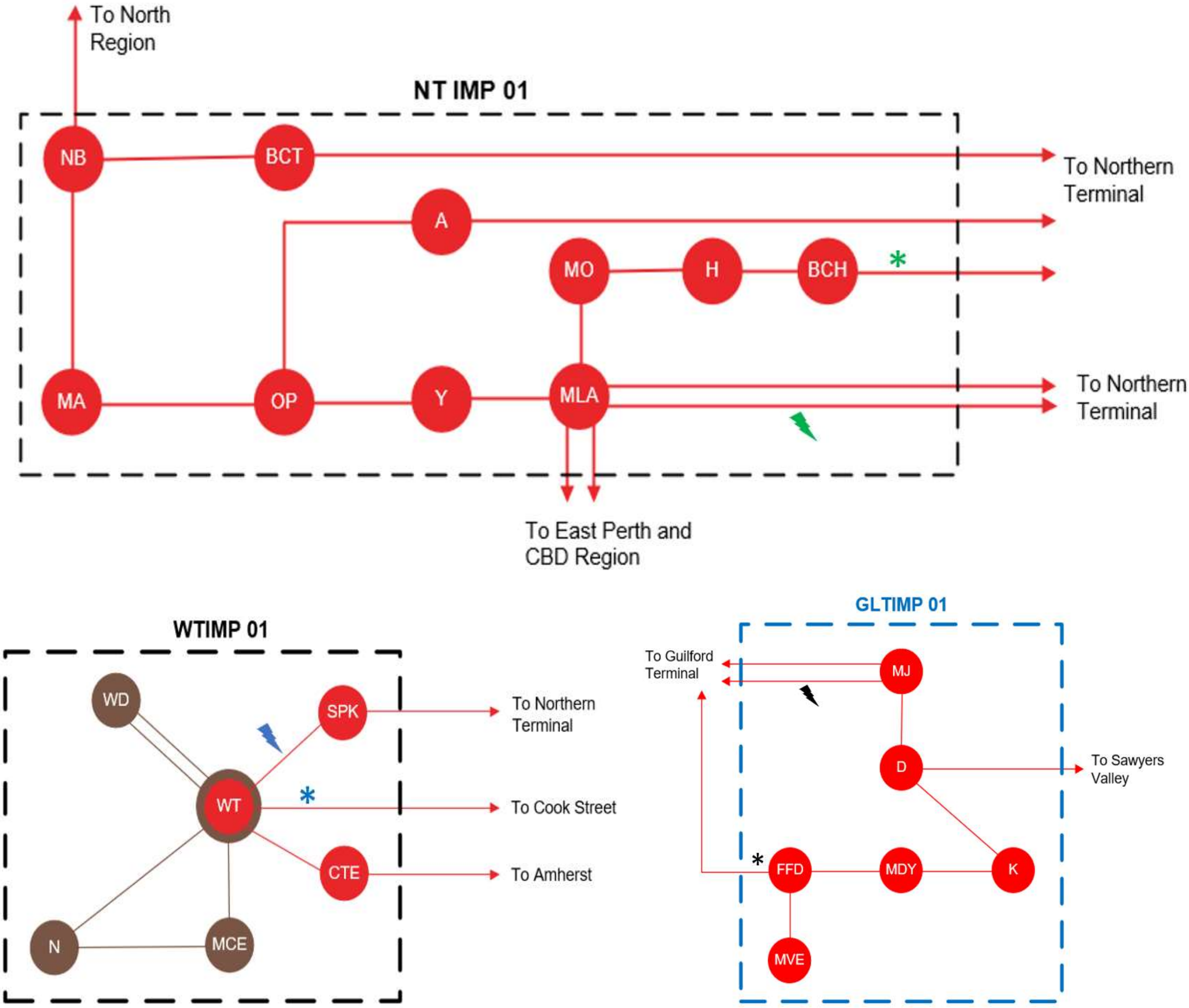

Figure 44: Network import boundaries in the Metro North Region

Table 21: Thermal import boundary characteristics – Metro North Region

Characteristics	Import Boundaries		
	WTIMP 01	NTIMP 01	GLTIMP 01
Worst contingency	Northern Terminal – Shenton Park 81	Northern Terminal – Mount Lawley 82	Guildford – Midland Junction 82
Contingency type	N-1	N-1	N-1
Worst circuit/s	Western Terminal – Cook St 81	Northern Terminal – Beechboro 81	Guildford – Forrestfield 81

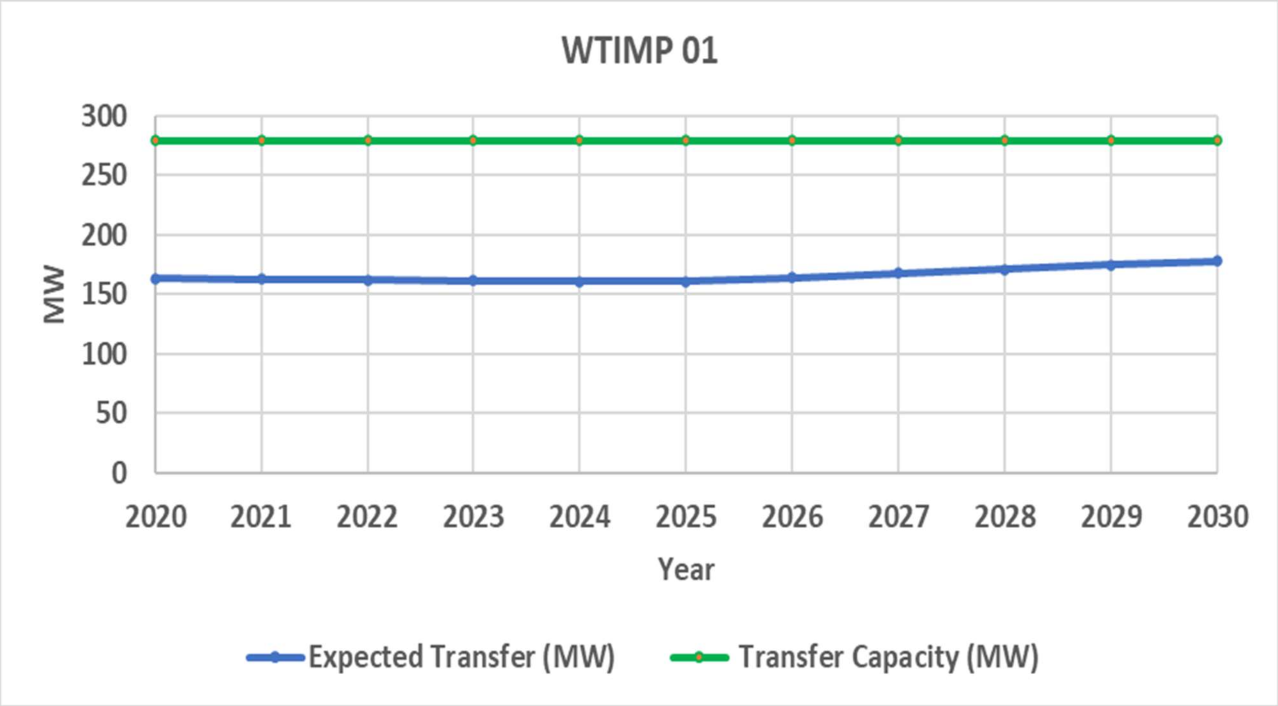

Figure 45: Expected transfer and transfer capacity in WTIMP 01 boundary – peak demand

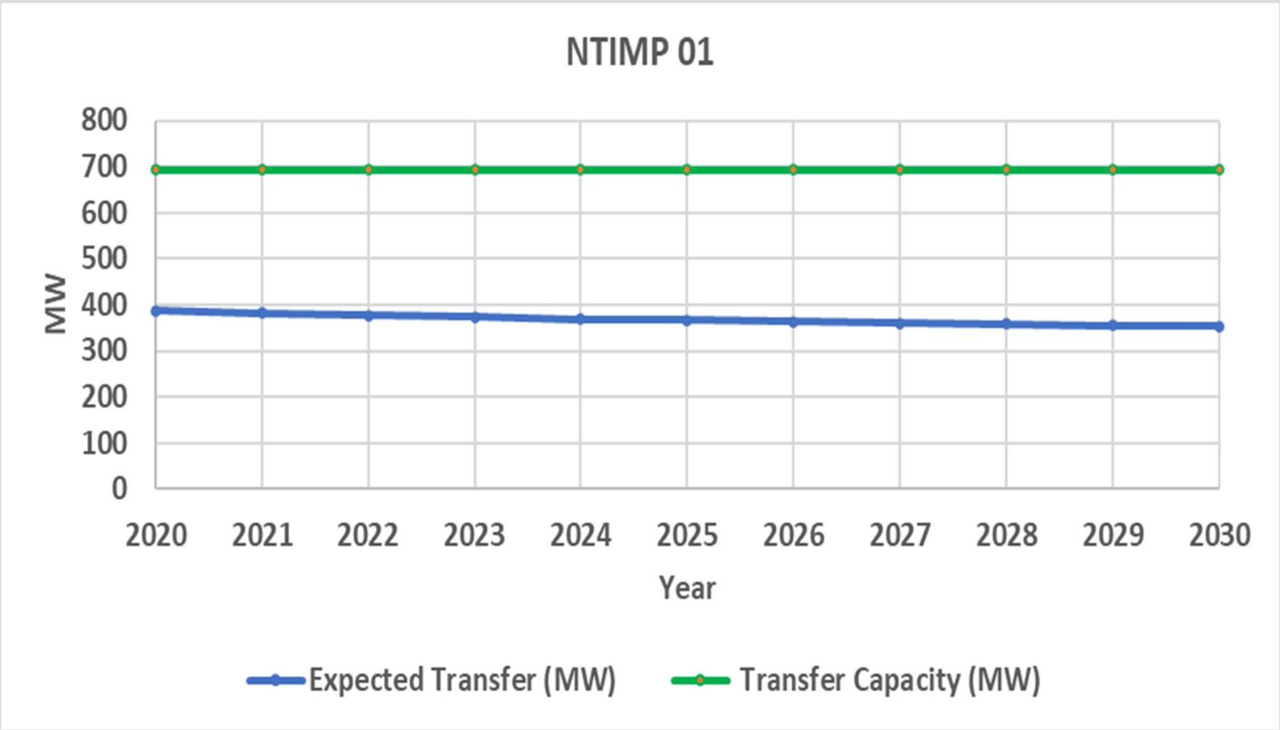

Figure 46: Expected transfer and transfer capacity in NTIMP 01 boundary – peak demand

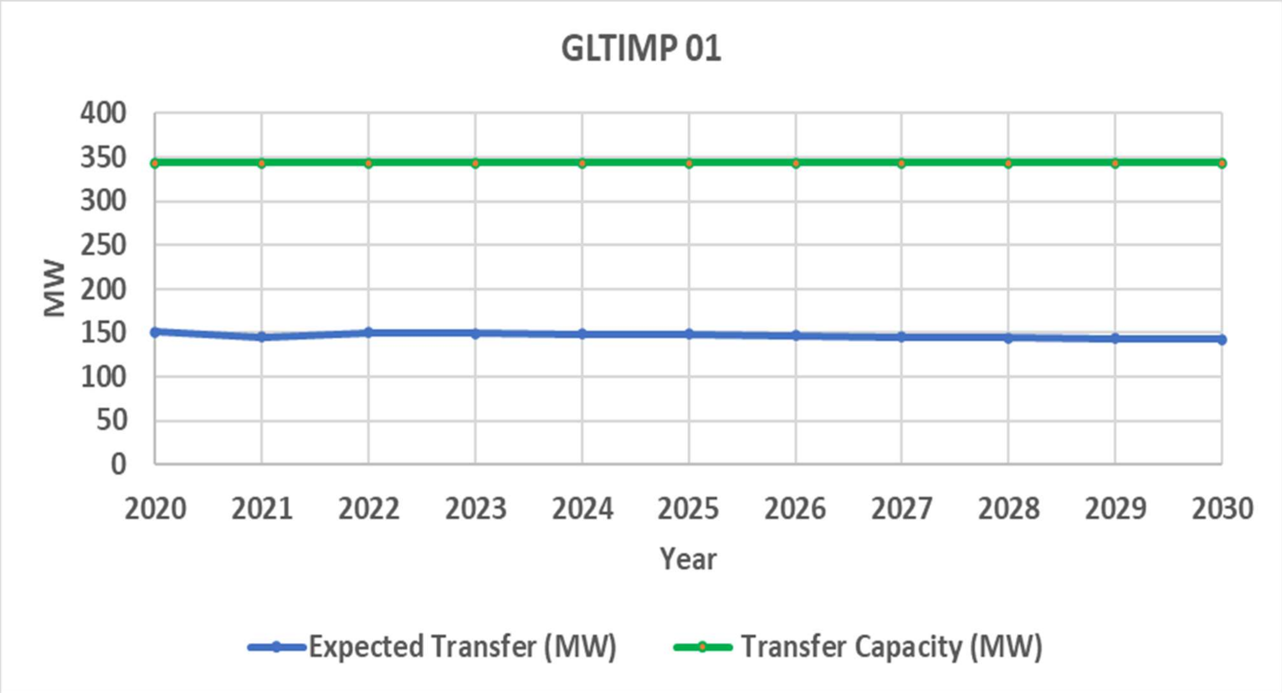

Figure 47: Expected transfer and transfer capacity in GLTIMP 01 boundary – peak demand

The above figures highlight that there is available capacity throughout all Metro North Region boundaries, however limited capacity to connect new load connections in the NT IMP 02 import boundary as expected transfers increase over the study period. The GLT IMP 01 import boundary has considerable available spare capacity, making it a suitable location to accommodate demand increases in the area.

13.3.2 Thermal Capacity – Transmission Lines

There are no thermal line performance constraints for the Metro North Region.

13.3.3 Thermal Capacity – Transformers

This section shows the existing and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the Metro North Region.

Table 22: Utilisation legend (for Table 23)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

Table 23: Metro North Region Zone Substation utilisation heat map[40]

Substation	Sub Capacity	Actual Utilisation (%)	Forecast Utilisation (%)																				Comment
	MVA	2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
	Current		PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	
Arkana	72	71	72	63	72	62	70	61	69	60	69	59	68	59	68	59	68	59	68	59	68	59	
Balcatta	53	30	30	27	30	26	31	26	31	26	32	27	34	28	36	29	37	31	39	32	41	33	
Beechboro	86	79	84	73	86	74	87	74	88	75	90	76	91	76	93	77	94	78	95	79	97	80	
Cottesloe	54	86	87	73	87	74	87	74	87	74	87	74	87	74	88	75	88	75	88	75	88	75	
Darlington	48	44	47	40	47	39	47	40	48	40	48	40	48	40	49	40	49	40	49	40	49	40	
Forrestfield	80	33	49	35	49	35	50	35	50	36	51	36	51	36	52	36	52	36	53	37	54	37	
Hadfield	77	66	66	59	65	58	64	57	64	57	63	56	62	56	62	55	61	55	61	54	60	54	
Hazelmere	27	88	93	85	93	85	93	85	93	85	93	85	93	85	93	85	92	85	92	85	92	85	
Henley Brook[41]	53	107	110	103	113	105	117	109	121	112	125	115	129	118	133	121	137	124	141	128	145	131	Additional transformer (Scoping, RIS year 2024)
Kalamunda	77	40	44	39	43	38	42	38	42	37	42	37	42	37	41	36	41	36	41	36	41	35	
Malaga	81	54	44	41	45	42	46	42	46	43	47	43	48	44	49	44	50	45	50	45	51	46	
Manning Street	43	78	78	64	78	63	76	62	74	61	72	60	70	59	69	58	68	57	68	57	67	56	
Medical Centre	83	59	60	57	61	58	62	59	63	60	64	61	65	62	66	63	67	64	68	65	68	65	

40 The Mount Lawley and Nedlands substations are not included in the above table. Mount Lawley 132 kV substation is a switchyard. Nedlands 66 kV substation has been de-energised.

41 Western Power is developing contingency plans to manage the substation capacity shortfall risks prior to the installation of an additional transformer

Midland Junction	94	64	64	58	64	57	64	57	64	57	64	57	64	57	63	56	63	56	63	56	63	56	
Morley	79	68	68	64	68	63	68	63	67	63	67	63	67	62	66	62	66	62	66	62	66	62	
Munday	54	42	46	44	46	44	46	44	46	44	46	44	46	44	46	44	46	44	46	44	46	44	
North Beach	75	77	77	69	76	68	75	66	74	65	73	64	72	63	71	62	69	61	68	60	67	59	
Osborne Park	63	78	83	79	80	76	79	75	78	75	78	74	77	73	76	73	76	72	75	71	75	71	
Shenton Park	71	72	72	65	75	69	76	69	76	69	76	69	76	69	76	69	76	69	75	69	75	68	
Wembley Downs	43	84	91	76	90	78	92	80	93	81	94	83	96	85	97	87	99	89	101	91	103	94	Managed by distribution transfers
Yokine	70	86	86	73	87	72	87	71	87	70	88	70	89	70	90	71	92	72	93	73	94	74	

13.3.4 Steady State Voltages

There are no voltage-related performance constraints within the Metro North Region over the study period.

13.3.5 Fault Levels

The Northern Terminal is a particularly congested site with numerous 330 kV and 132 kV transmission line connections. Under current network configurations during high demand conditions, fault levels can become problematic and 132 kV disconnectors at Mount Lawley can become under fault rated under certain operating conditions. Western Power has addressed these limitations by operating the Mount Lawley Substation 132 kV buses split under some operating conditions.

13.3.6 Stability

There are no stability-related performance constraints within the Metro North Region over the study period.

13.3.7 Reliability

There are no reliability-related performance constraints within the South Region over the study period.

13.3.8 Asset

Existing asset performance constraints were identified in the Metro North Region within the study period, including:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
    - Arkana – 132/22 kV 33 MVA/27 MVA – T1 & T3
    - Darlington – 132/22 kV 10 MVA – T1
    - Hadfield – 132/22 kV 27 MVA – T1
    - Kalamunda – 132/22 kV 33 MVA – T3
    - Midland Junction – 132/22 kV 30 MVA – T1 & T2
    - North Beach– 132/22 kV 27 MVA – T1 & T3
    - Northern Terminal – 330/132 kV 490 MVA – T1 & T2
    - Osborne Park– 132/11 kV 27 MVA – T1
    - Wembley Downs – 132/11 kV 27 MVA/ 32 MVA – T1 & T4
    - Western Terminal – 132/66 kV 100 MVA – T1 & T2
- The 11 kV switchboards at Manning Street and Yokine and the 22 kV Hadfield's switchboards are in degraded condition and need to be addressed in the next 10 years.

13.4 Network Augmentation Works

Committed, completed and proposed transmission projects in the Metro North Region are shown in Table 24.

Table 24: Completed, committed and proposed projects – Metro North Region

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Northern Terminal: 330 kV bay upgrade works	Upgrade the existing 330 kV Northern Terminal to Muja circuit with a full 330 kV line circuit.	Provide operational flexibility to switch out the Muja to Northern Terminal 330 kV circuit as it generates significant reactive power during low system demand conditions. Without this, the voltage management and frequency stability risks that can arise due to a shortfall in reactive power absorption capability will increase.	Growth – Voltage	2021/22	Completed
Maida Vale Substation: New PTA traction supplies	A new 132 kV supply from Forrestfield substation to the new Maida Vale Substation.	Facilitate the connection of new PTA traction supplies	Customer Driven	2021/22	Completed
Yokine: Switchboard replacement	Replacement of the existing 11 kV indoor switchboard at Yokine substation.	Address degraded asset condition issues	Asset Condition	2022/23	Execution
North Beach Substation: Transformer replacement	Replace the existing 132/22 kV 27 MVA T3 transformer with a new 33 MVA unit.	Address degraded asset condition issues and accommodate increasing demand in the area.	Asset Condition	2022/23	Execution
Nedlands Substation: Decommissioning	Removal of redundant 66 kV assets and partial removal of the Western Terminal – Nedlands 66 kV supplies at the existing 66 kV Nedlands Substation.	Address degraded asset condition issues	Asset Condition	2024/25	Execution
Manning St Substation: Switchboard and relay room replacement and new relay room	Replacement of the existing 11 kV indoor switchboard and relay room at Manning St Substation.	Address degraded asset condition issues	Asset Condition/ Growth – Thermal	2024/25	Planning
Osborne Park Substation: Transformer replacement	Replace the existing 132/22 kV 27 MVA T1 transformer with a new 33 MVA unit.	Address degraded asset condition issues and accommodate increasing demand in the area.	Asset Condition	2023/24	Planning
Henley Brook Substation: New Transformer	Installation of a third 132/22 kV 33 MVA transformer at Henley Brook Substation	Address substation capacity shortfall and accommodate increasing demand in the area.	Growth – Thermal	2023/24	Scoping

13.5 Network Opportunities

This section highlights network opportunities in the Metro North Region over the study period.

Table 25: Network Opportunities projects – Metro North Region

Project	Scope / Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Henley Brook: New Transformer	Installation of a third 132/22 kV 33 MVA transformer at Henley Brook Substation	Reduce the demand supplied By Henley Brook Substation during peak demand conditions to potentially reduce or defer network augmentation to increase the power transfer capacity to the area.	2023/24	Scoping	7-9
WT IMP 01, NT IMP 01 and GLT IMP 01 available import capacity	Spare available import capacity exists over a number of import boundaries within the Metro North Region.	An opportunity exists to utilise spare available capacity within WT IMP 01, NT IMP 01 and GLT IMP 01 import boundaries by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a

13.6 Emerging Issues and Drivers

The Metro North Region is predominately a load centre. As shown in section 0, most parts of the region have available spare capacity to connect additional load connections, without triggering the need for network augmentation.

The 66 kV networks supplied from the Western Terminal require mitigation in the next 10 to 20 years and Western Power is investigation options to either retire or upgrade these supplies to 132 kV as they approach their end of service life.

Although the progressive retirement of coal units at Muja and Collie represents a significant change to the SWIS, the Metro North Region is predominately a load centre and is expected to be less impacted than other regions. Upgrades at the Northern and Guildford terminal are anticipated to support likely bulk power flows, particularly as industries look to decarbonise.

Western Power is working with industry to better understand how the proliferation of EVs will impact the network in the Metro North Region. Due to the high density of load in this region (particular along river and coastal areas), increased EV usage is likely to trigger the need to increase capacity on the transmission system. This may create challenges with service congestion, scarcity of available land, construction of new transmission lines and substations, as well environmental and community approvals.

14 Metro South Region

14.1 Geography

The Metro South Region covers a large area, including most of the urban Perth metropolitan networks south of river, from the Cannington Terminal in the east to the Southern and South Fremantle Terminal towards the west. The region also covers the southern metropolitan coastal strip from Kwinana through to Rockingham and Mandurah, and extends east to encompass the Pinjarra Substation. The network diagram for this region is split across Figure 48 and Figure 49 for illustration purposes only.

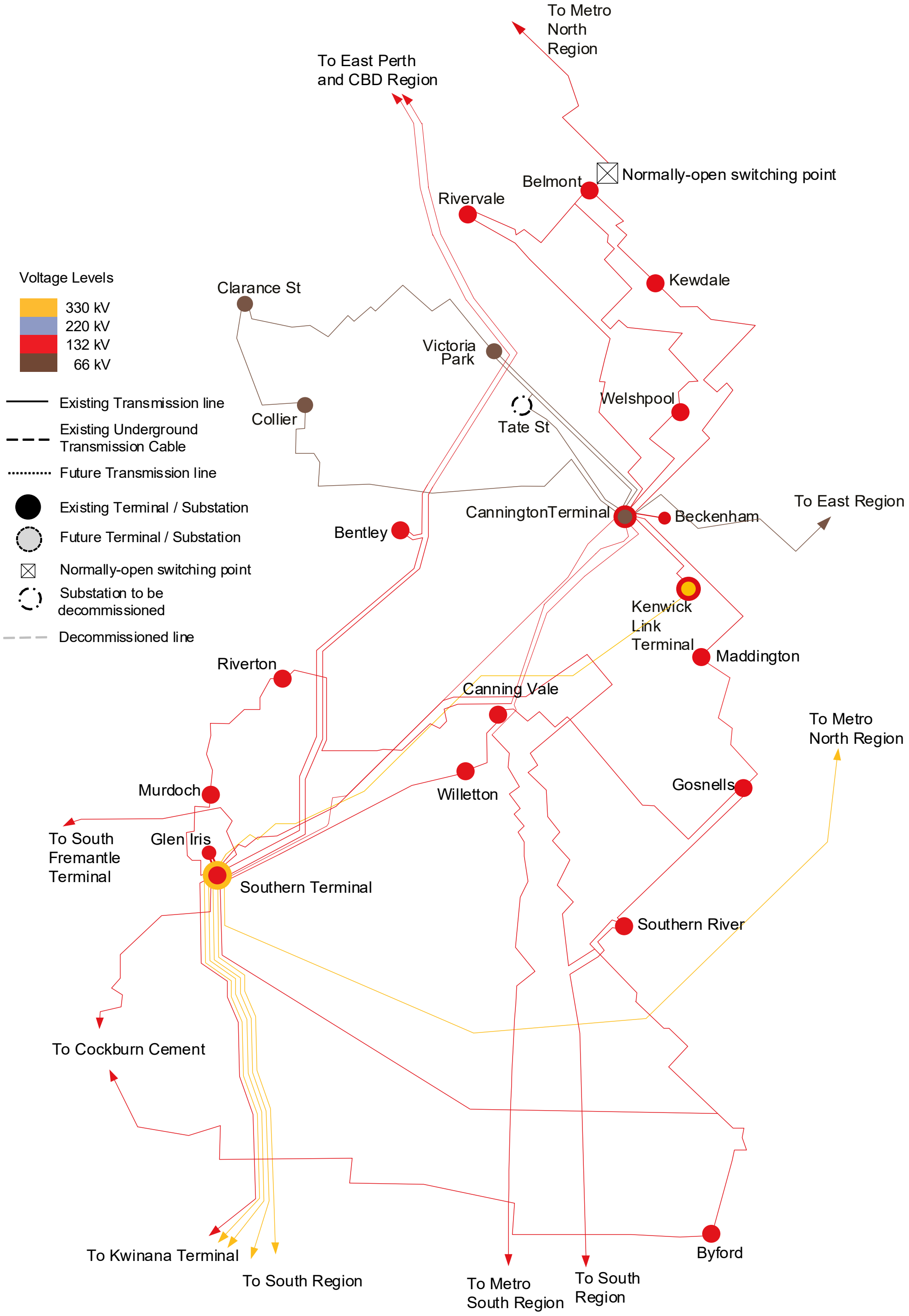

Figure 48: Western Power's Metro South Region (Part A) – Network Diagram

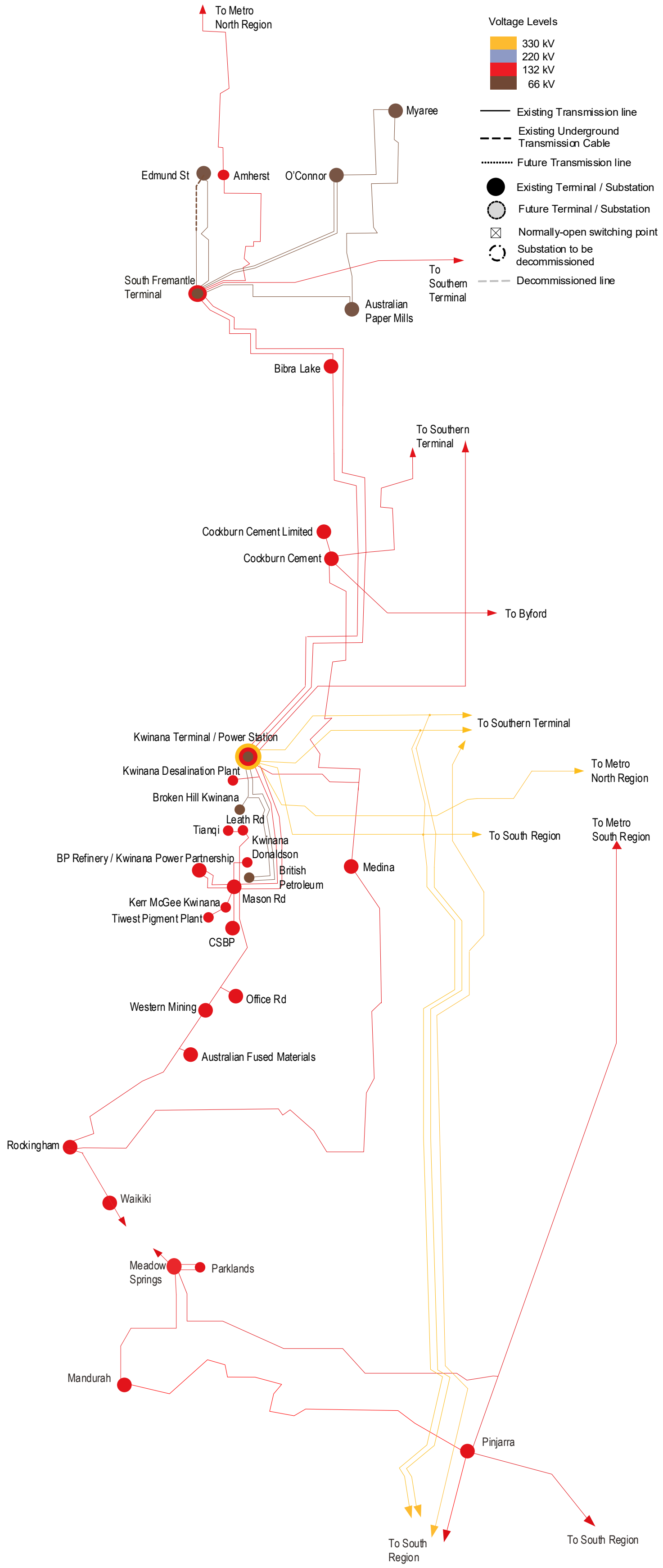

Figure 49: Western Power's Metro South Region (Part B) – Network Diagram

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The Metro South Region consists of five terminals – South Fremantle, Kwinana, Southern, Cannington and Kenwick Link - and 33 zone substations owned and operated by Western Power. The other transmission sites in the Metro South Region are customer-owned substations.

Terminal

- Kwinana Terminal 330/132/66 kV
- South Fremantle Terminal – 132/66 kV
- Southern Terminal – 330/132 kV
- Cannington Terminal 132/66 kV
- Kenwick Link Terminal 330/132 kV

Zone Substations / WP Substations

- Amherst – 132/22 kV
- Australian Paper Mills – 66/22 kV
- Beckenham – 132/22 kV
- Belmont – 132/22 kV
- Bentley – 132/22 kV
- Bibra Lake – 132/22 kV
- Byford 132/22 kV
- Canning vale – 132/22 kV
- Clarence St – 66/11 kV
- Collier – 66/11 kV
- Cockburn Cement – 132/22 kV
- Edmund Street – 66/11 kV
- Glen Iris – 132/22 kV
- Gosnells – 132/22 kV
- Kewdale – 132/22 kV
- Maddington – 132/22 kV
- Mandurah – 132/22 kV
- Mason Road – 132/22 kV
- Medina – 132/22 kV
- Meadow Springs – 132/22 kV
- Murdoch – 132/22 kV
- Myaree – 66 /22 kV
- O'Connor – 66/22 kV
- Pinjarra – 132/22 kV
- Rivervale – 132/22 kV
- Riverton – 132/22 kV
- Rockingham – 132/22 kV
- Southern River 132/22 kV
- Tate Street – 66/22 kV[42]
- Victoria Park – 66/11 kV
- Waikiki – 132/22 kV
- Welshpool – 132/22 kV
- Willetton – 132/22 kV

Customer substations

- Alcoa Kwinana – 132 kV
- Australian Fused Materials 132 kV
- British Petroleum – 66 kV
- Broken Hill – 66 kV
- CSBP – 132 kV
- Cockburn Cement Limited – 132 kV
- Cockburn Power Station – 132 kV
- Kerr McGee Kwinana – 132 kV
- Kwinana Donaldson Road – 132 kV
- Kwinana Desalination Plant – 132 kV
- Kwinana Power Partnership – 132 kV
- Leath Road – 132 kV
- Office Road – 132 kV
- Parklands 132 kV
- Tianqi Lithium Australia – 132 kV
- Western Mining 132 kV

[42] Both Tate St and Victoria Park 66 kV substations are still energised however, their transformers have been removed and loads transferred to neighbouring substations

14.2 Regional Characteristics

14.2.1 General

The Metro South Region covers the southern suburbs, which supplies a diverse mixture of residential, commercial and light/heavy industrial load. It also includes popular tourist spots, Fremantle and Mandurah. Most residential load is supplied out of the Southern Terminal, parts of Cannington and the South Fremantle Terminal and the Mandurah area. Large light/heavy industrial load areas are supported in the east of the region and to the west providing supply to Fremantle Port. The Kwinana area has historically been a site for generation connections and plays a significant role in State development by supporting large scale heavy industry and presenting attractive opportunities for future developments.

14.2.2 Generation

The Kwinana Terminal area is a key supply point for the rest of the Western Power Network, with a number of high-capacity supplies at both 132 kV and 330 kV. The strength of the network, coupled with the availability of gas fuel resources, has created a strong attraction for new generation entrants to be sited in the area. As Western Power continues to receive considerable interest for new entrant generation developments, Kwinana is likely to remain as a key generation hub into the foreseeable future.

14.2.3 Existing Transmission Network Supply

The Kwinana and Southern terminals share large bulk supplies on both the 132 kV and 330 kV networks, with the Southern Terminal a key focal point of supply into the Perth metropolitan area. In addition, a number of 66 kV loops within the South Fremantle, Cannington and Kwinana regions are nearing their end of service life.

The Metro South Region consists of five bulk terminals which supply zone substations via 330 kV, 132 kV and 66 kV sub-transmission networks. Due to the highly meshed nature of 132 kV transmission network in this region, the 132 kV network has become over-utilised in certain parts, while the 330 kV network remains under-utilised.

14.2.4 Key Developments In the Region

A number of new developments in the Kwinana area have resulted in two new 132 kV substations, Office Road Substation and Leath Road, that have supported a waste-to-energy generation connection and a lithium processing load connection. Furthermore, Synergy's 100 MW/ two-hour large-scale battery connection is anticipated to be operational by 2022/23 and will support integration of more renewable energy and improve grid stability.

14.3 Network Performance

This section presents the network performance for the Metro South Region over the study period.

14.3.1 Thermal Capacity – boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and security constrained and economic dispatch conditions.
- Export boundaries consider peak demand and maximum generation dispatch conditions (within boundary).
- The KW T1 bus tie transformer is out of service.

Import Boundaries

Figure 50 and Figure 51 show the network import boundaries in the Metro South Region. These boundaries are defined using the worst contingency (⚡) and the worst overload circuit (*) as shown in Table 26.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 52 to Figure 55.

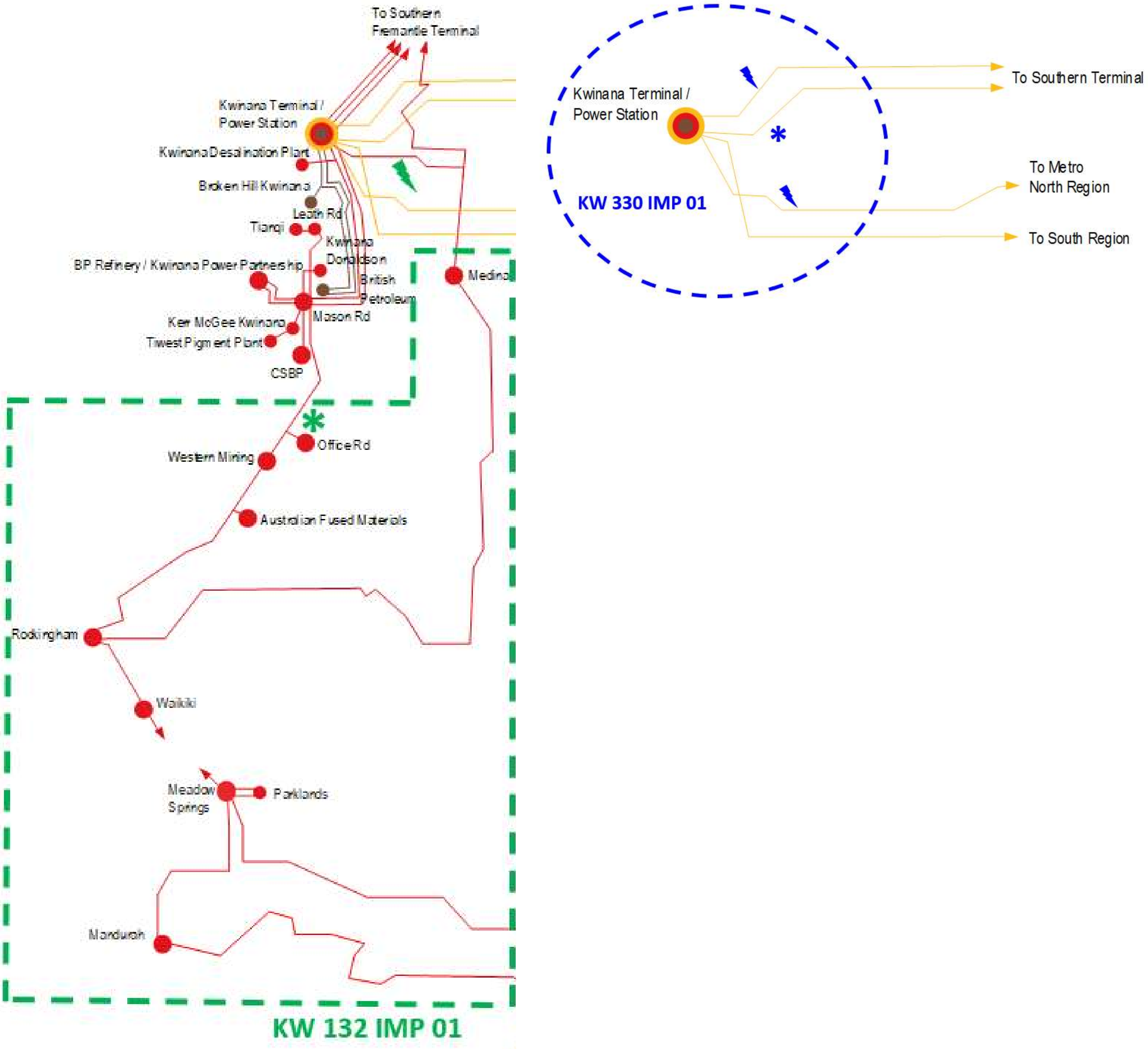

Figure 50: Network import boundaries in the Metro South Region – Kwinana 330 kV and 132 kV

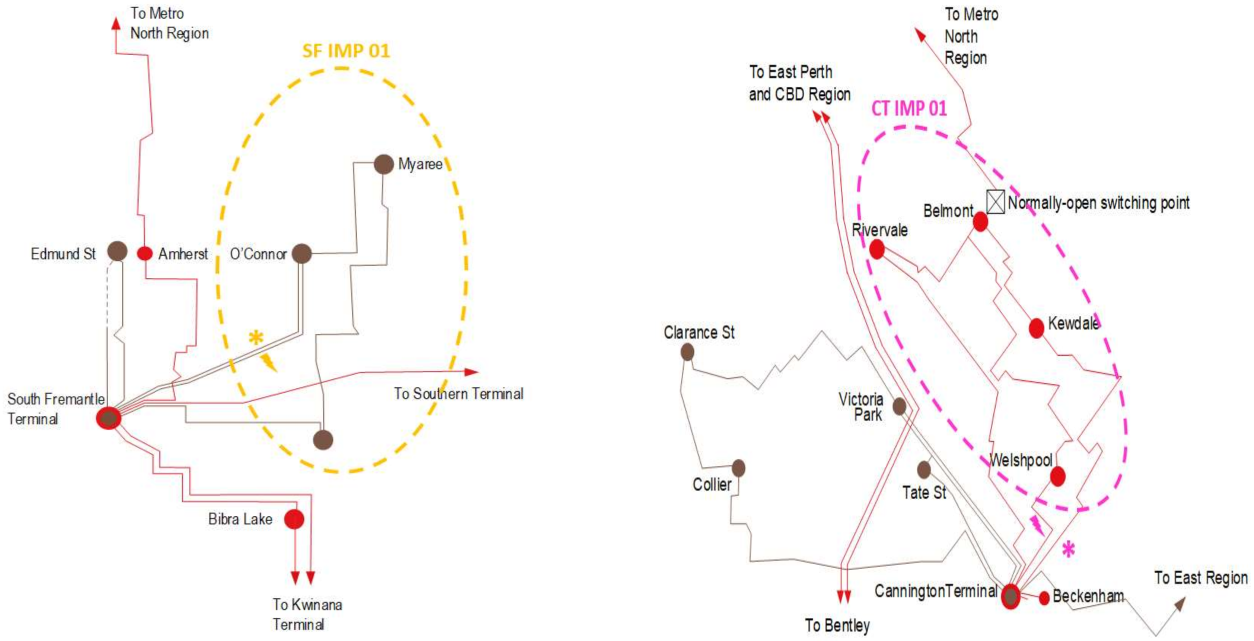

Figure 51: Network import boundaries in the Metro South Region – South Fremantle and Cannington

Table 26: Thermal import boundaries characteristics – Metro South Region

Characteristics	Import Boundaries			
	KW330IMP 01	KW132IMP 01	SFIMP 01	CTIMP 01
Worst contingency	Kwinana – Southern Terminal 92 and Kwinana-Kemerton/Oakley 91	Medina-Cockburn Cement/Kwinana 81	South Fremantle - O'Connor 71	Cottesloe-Western Terminal 81
Contingency type	N-1-1	N-1	N-1	N-1
Worst circuit/s	Kwinana – Southern Terminal 91	Mason Rd – Western Mining 81	South Fremantle-O'Connor 72	Cannington Terminal – Kewdale 81

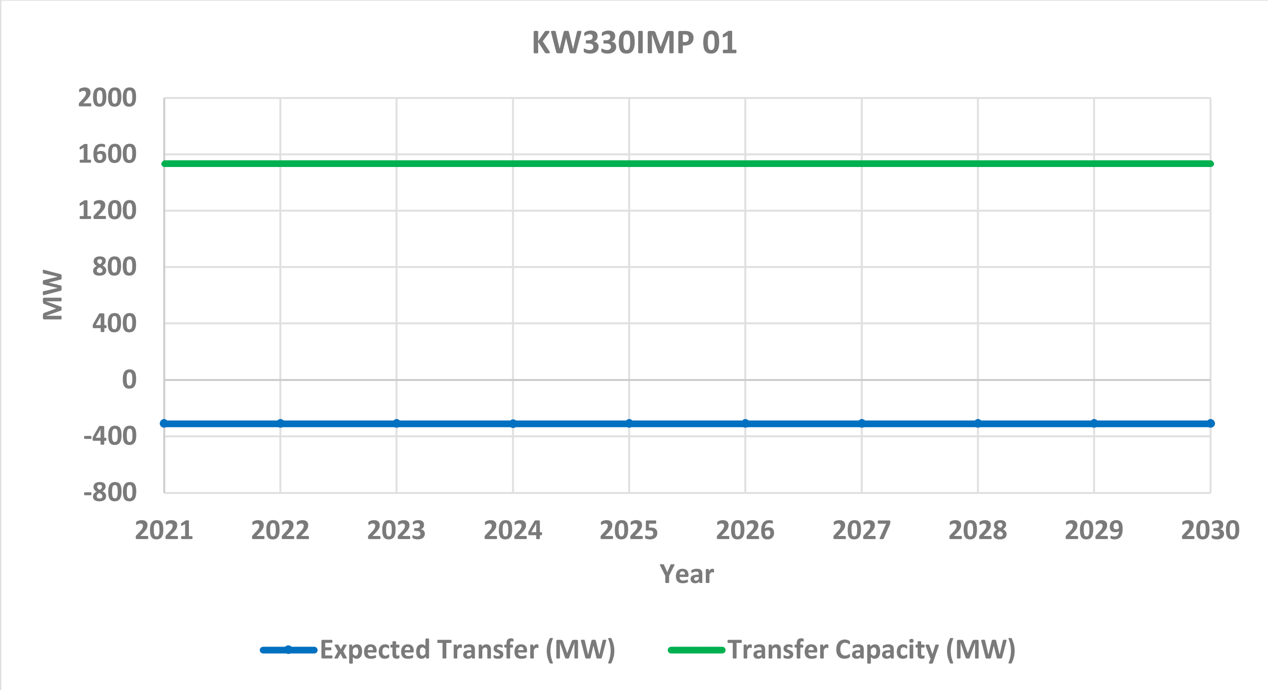

Figure 52: Expected transfer and transfer capacity in KW330IMP 01 boundary – peak demand

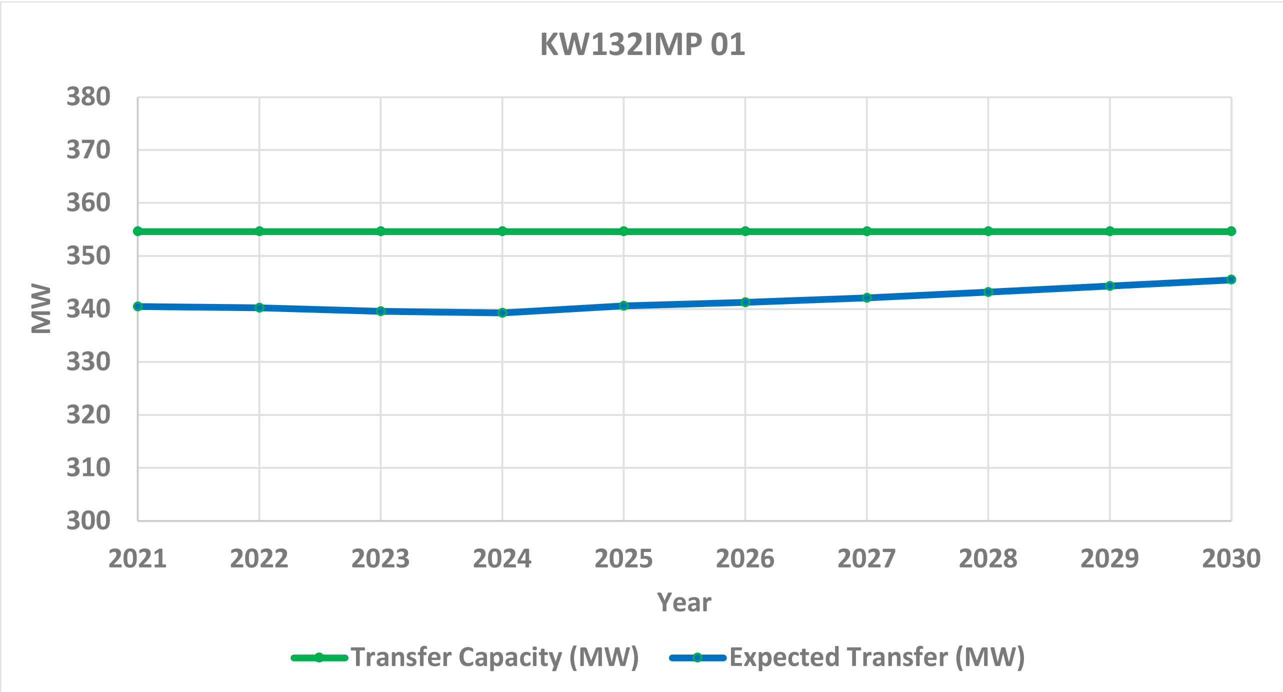

Figure 53: Expected transfer and transfer capacity in KW132IMP 01 boundary – peak demand

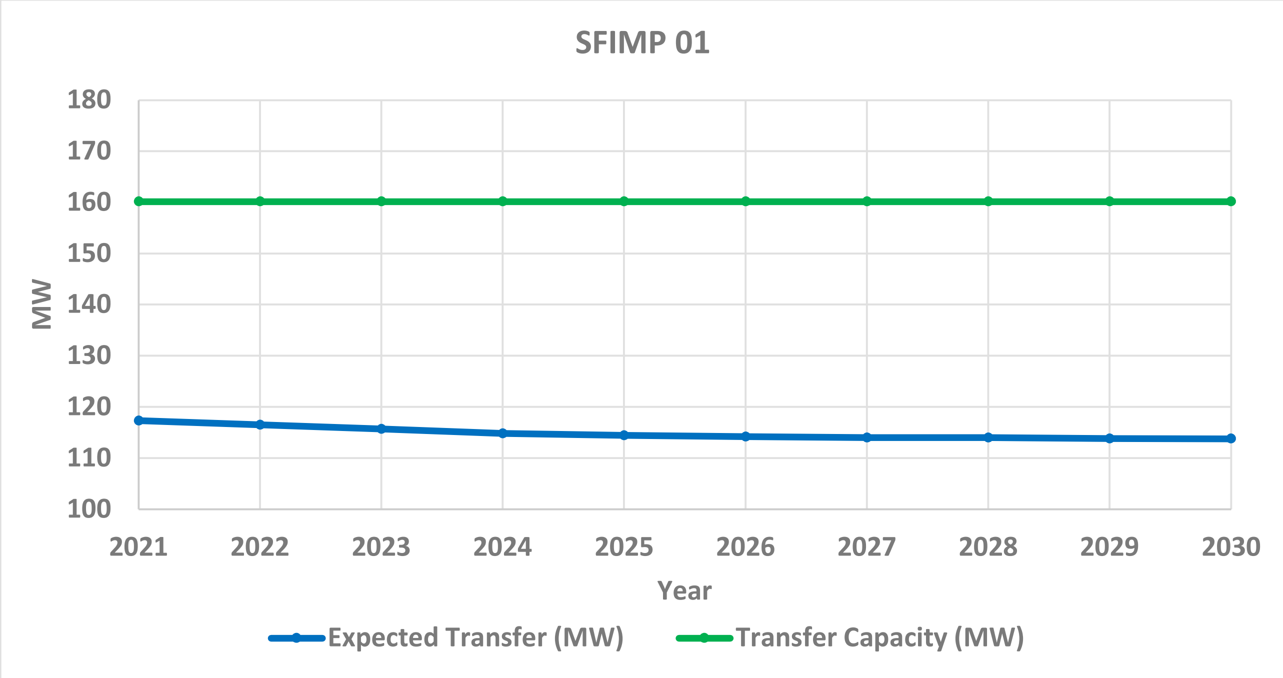

Figure 54: Expected transfer and transfer capacity in SFIMP 01 boundary – peak demand

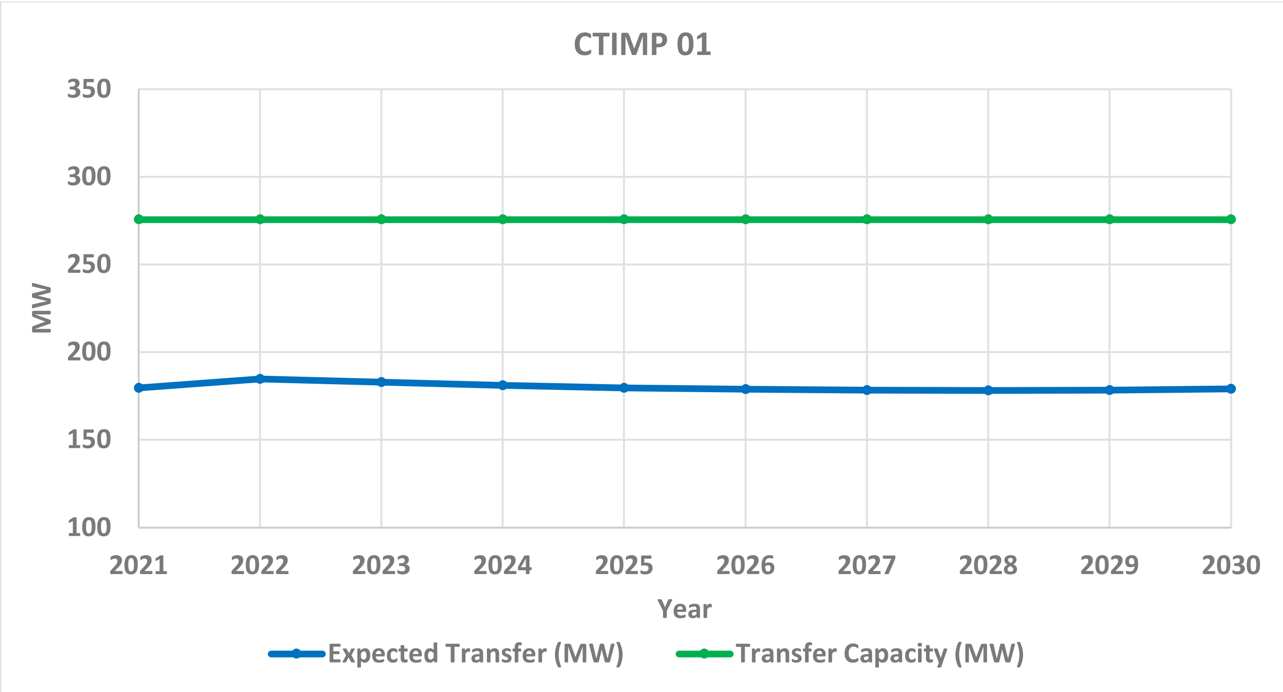

Figure 55: Expected transfer and transfer capacity in CTIMP 01 boundary – peak demand

As observed in the above figures, the KW 330 IMP boundary is a net exporter of power during peak demand periods. Under N-1-1 conditions there is approximately 1800 MW of available transfer capacity, making it a suitable candidate to support new large block load connections. The available capacity in the KW 132 IMP boundary is very limited, with new reference load connections likely to require network augmentation works. The SFIMP 01 and CTIMP 01 import boundaries have available capacity to accommodate increasing and new load connections.

Export Boundaries

Figure 56 shows the network import boundaries in the Metro South Region. These boundaries are defined using the worst contingency (↯) and the worst overload circuit (*) as shown in Table 26.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 52 to Figure 55.

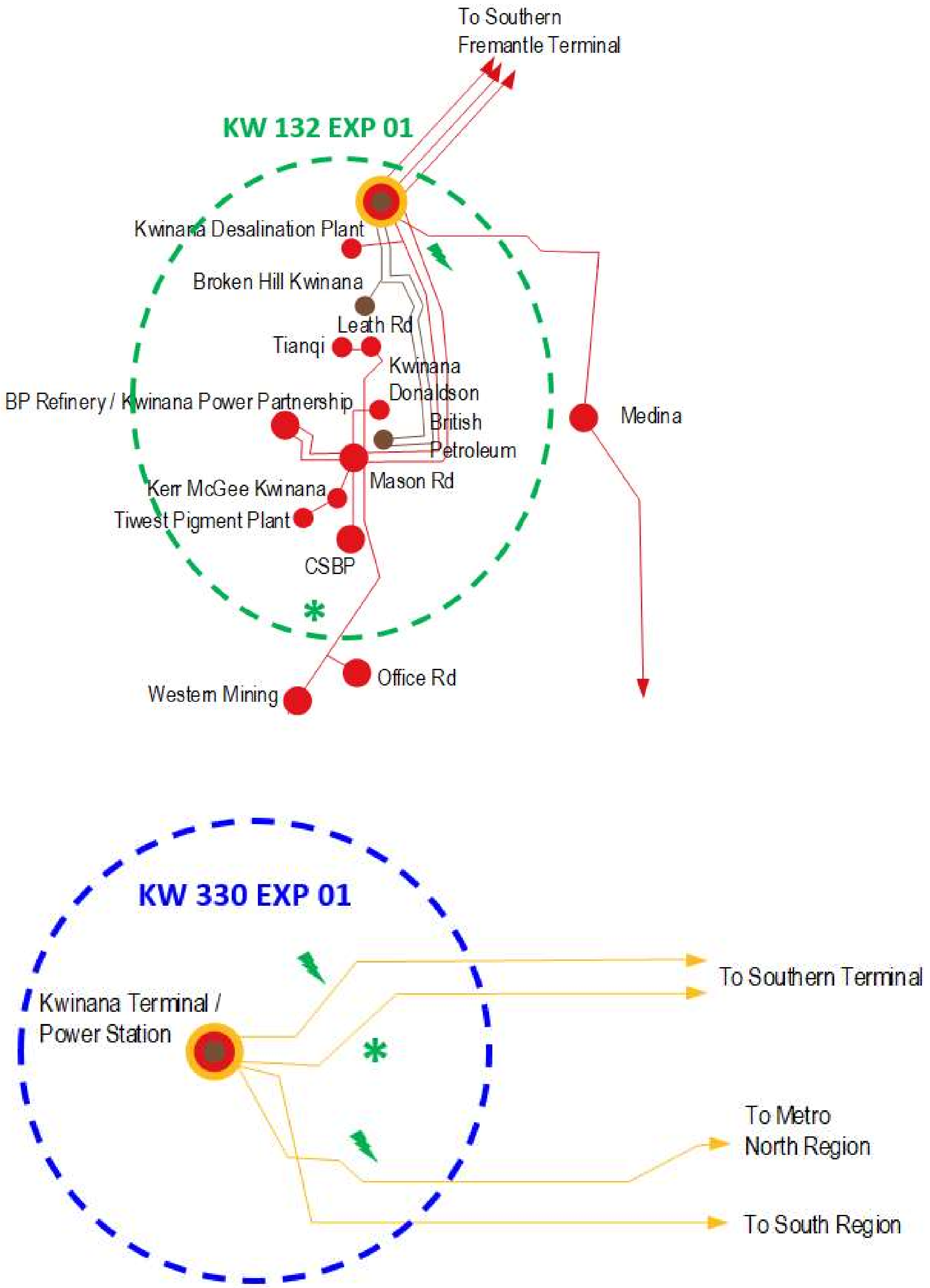

Figure 56: Network export boundaries in the Metro South Region

Table 27: Thermal export boundaries characteristics – Metro South Region

Characteristics	Export Boundaries	
	KW330EXP 01	KW132EXP 01
Worst contingency	Kwinana – Southern Terminal 92 and Kwinana-Kemerton/Oakley 91	Kwinana-Cockburn Cement/Medina 81
Contingency type	N-1-1	N-1
Worst circuit/s	Kwinana – Southern Terminal 91	Mason Road – Western Mining 81

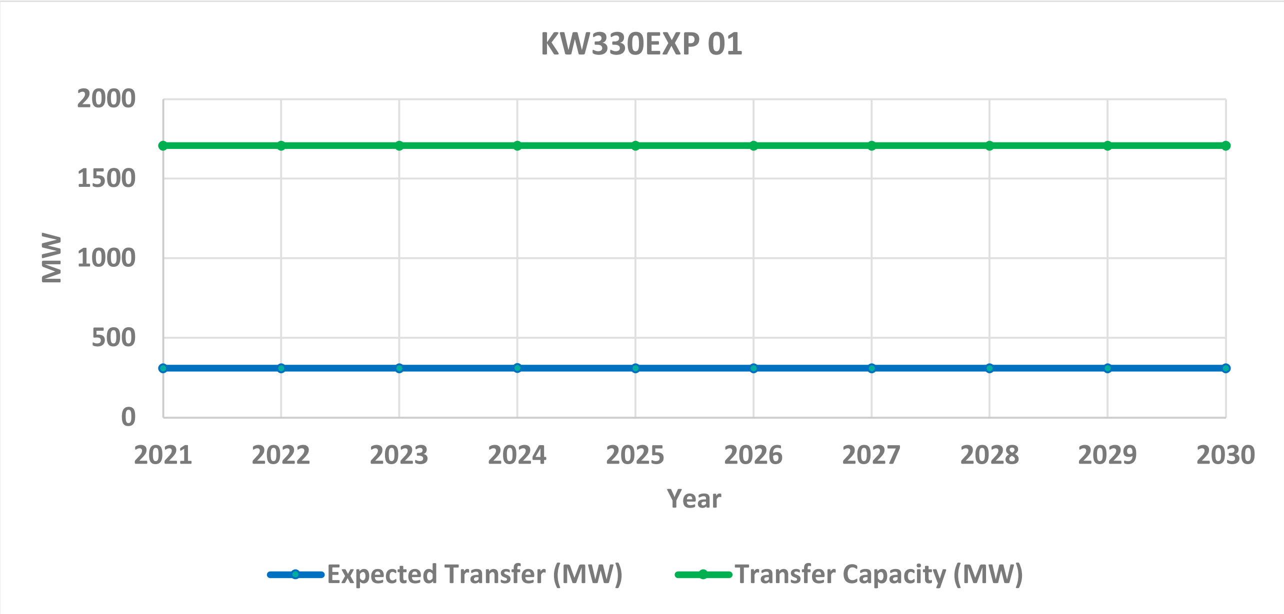

Figure 57: Expected transformer and transfer capacity in KW330EXP 01 boundary – peak demand

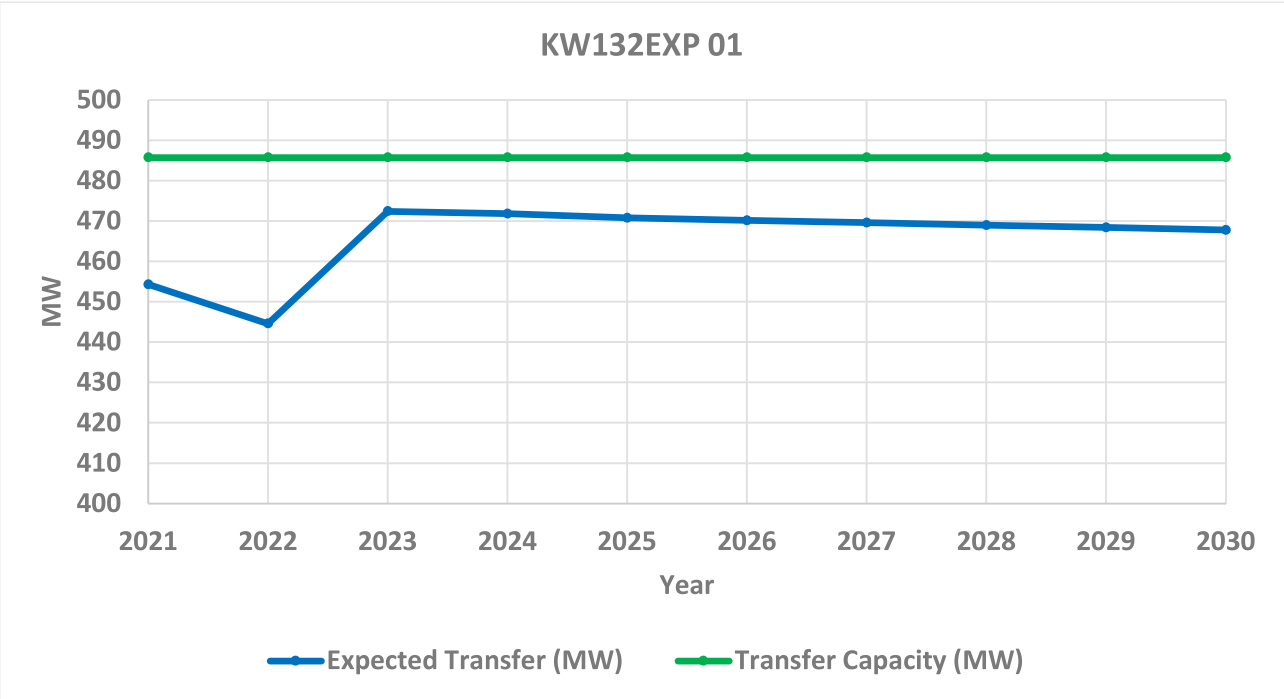

Figure 58: Expected transfer and transfer capacity in KW132EXP 01 boundary – peak demand

Under N-1-1, the KW330EXP 01 export boundary has almost 1400 MW of available capacity, which makes it a suitable candidate to connect new large-scale generation. The Kwinana 132 kV export boundary (KW132EXP 01) has very limit available capacity (approximately 15 MW) over the study period and would require network augmentation to facilitate new generation connections.

14.3.2 Thermal Capacity – Transmission Lines

Post contingent thermal overloads arise during peak demand conditions within the Metro South Region over the study period on the following circuits:

- Medina to Cockburn Cement / Kwinana 132 kV line overloads occur by 2022/23 and increase up to 116 per cent, following the loss of the Mason Road to Western Mining / Office Road 132 kV line.
- Mason Road to Western Mining / Office Road 132 kV line overloads occur by 2021/22 and increase up to 123 per cent, following the loss of the Cockburn Cement to Medina 132 kV line.
- Rockingham to Western Mining / Australian Fused Materials 132 kV line overloads occur by 2026/27 and increase up to 105 per cent, following the loss of the Cockburn Cement to Medina 132 kV line.
- Southern River to Wagerup / Alcoa Pinjarra 132 kV line marginal overloads occur by 2020/21 and increases up to 101 per cent, following the loss of the Pinjarra to Alcoa Pinjarra 132 kV line.

14.3.3 Thermal Capacity –Transformers

This section shows the existing and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the Metro South Region.

Table 28: Utilisation legend (for Table 29)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

Table 29: Metro South Region Zone Substation utilisation heat map

Substation	Sub Capacity	Actual Utilisation (%)	Forecast Utilisation (%)																				Comment
	MVA	2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
			PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	
Amherst	85	83	80	67	80	66	81	66	81	65	82	65	83	65	83	65	84	65	85	65	86	65	
Australian Paper Mills	46	65	64	58	65	58	65	58	66	57	67	57	68	57	69	57	70	57	71	57	72	56	
Belmont	72	59	58	52	56	51	54	50	54	49	53	49	53%	49	53	49	53	49	53	49	53	49	
Bentley	56	36	39	37	76	71	76	71	75	70	74	69	73	69	73	68	72	67	71	67	71	66	Load transfer from TT (Execution, RIS year 2023)
Bibra Lake	56	96	98	84	99	85	100	86	101	87	102	87	103	88	104	89	105	89	106	90	107	91	Additional transformer (Initiation, RIS year 2028)
Byford[43]	77	96	105	97	107	99	109	101	111	103	113	105	115	107	117	109	118	111	120	113	122	115	Additional transformer (Scoping, RIS year 2025)
Cockburn Cement	77	56	60	57	60	57	58	55	56	53	54	51	52	49	50	47	48	45	46	43	44	41	
Clarence St	43	69	69	60	68	58	67	57	66	55	65	53	64	52	63	50	63	49	62	47	61	46	
Collier	69	60	53	51	53	51	53	52	54	52	54	52	54	53	54	53	55	53	55	53	55	54	
Canningvale	93	59	56	54	55	53	55	52	54	50	53	49	52	49	52	48	51	47	51	46	50	45	
Edmund St	43	62	61	54	60	53	59	52	59	52	59	52	60	52	61	53	61	54	62	54	63	55	
Gosnells	77	76	74	69	71	66	67	63	64	60	61	57	58	54	55	52	52	49	50	47	47	44	
Kewdale	56	59	58	51	65	58	64	57	63	56	62	55	61	53	60	52	60	51	59	49	58	48	Load transfer from TT (Execution, RIS year 2023)
Maddington	26	86	89	76	92	79	96	82	99	85	102	88	105	91	109	94	112	97	115	100	117	102	Managed by distribution transfers

43 Western Power is developing contingency plans to manage the substation capacity shortfall risks prior to the installation of an additional transformer

Medina	81	68	65	55	65	55	66	56	66	57	67	58	67	59	67	60	68	61%	68	62	68	62	
Mandurah	76	97	100	89	99	87	98	86	98	85	98	84	98	83	98	83	98	82	98	82	98	82	Managed by distribution transfers
Mason Rd	74	64	60	63	62	65	64	66	65	68	67	68	68	69	69	70	71	71	72	72	74	73	
Meadow Springs	86	81	83	73	84	74	84	75	84	75	85	75	85	76	85	76	86	76	86	77	86	77	
Murdoch	54	70	71	66	71	66	71	66	71	66	71	66	71	66	72	66	72	66	72	66	72	66	
Myaree	65	56	55	57	55	56	56	54	57	52	57	51	58	49	59	47	59	46	60	44	60	42	
O’Connor	70	69	73	65	72	64	72	63	74	65	77	67	80	70	84	73	87	76	91	79	95	82	
Pinjarra	57	36	42	37	44	39	45	40	46	41	47	41	48	42	49	43	49	44	50	44	51	45	
Rockingham	75	73	71	64	71	64	72	64	72	64	72	64	72	64	72	64	72%	64	72	65	72	65	
Riverton	81	92	86	70	86	72	85	73	85	74	84	75	83	77	83	78	82	79	82	80	81	81	
Rivervale	83	57	57	53	71	65	71	65	71	65	70	65	70	64	70	64	69	64	69	63	69	63	Load transfer from TT (Execution, RIS year 2023)
Southern River	85	92	93	83	95	85	97	87	99	89	102	91	104	93	106	94	108	96	110	98	112	100	Load transfer from BYF (Scoping, RIS year 2025)
Tate St	72	56	59	54	59	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Substation retirement (Execution, RIS year 2023).
Waikiki	80	93	95	86	97	87	98	88	99	89	100	90	102	91	103	92	104	94	105	95	107	96	Managed by distribution transfers
Welshpool	90	69	70	66	75	69	74	68	74	66	73	64	73	63	73	62	73	60	73	59	73	57	Load transfer from TT (Execution, RIS year 2023)
Willetton	26	86	85	76	82	72	78	69	75	66	72	63	70	60	67	58	65	55	62	53	60	50	

14.3.4 Steady State Voltages

Voltage related performance constraints within the Metro South Region arise during peak demand conditions over the study period, including:

- Low voltages (0.88 pu) and excessive voltage step conditions (-10.1 per cent) by 2028/29 at the Waikiki 132 kV busbar, following the loss of the loss of the Rockingham-Waikiki 132 kV line.

14.3.5 Fault Levels

Due to the heavily meshed 330 kV and 132 kV network at Southern Terminal, fault levels during peak demand conditions are high and can potentially exceed certain plant and earth grid rating if unmanaged. A significant contribution to fault levels comes from the direct 132 kV connection between the Kwinana and Southern terminals, which raises fault levels considerably at both sites. Western Power currently manages this risk by temporarily opening the Southern Terminal to Kwinana 81 circuit during peak demand conditions to reduce fault levels.

14.3.6 Stability

There are no stability-related performance issues in the Metro South Region within the study period.

14.3.7 Reliability

There are no reliability-related performance issues in the Metro South Region within the study period.

14.3.8 Asset

Existing asset performance issues have been identified in the Metro South Region within the study period, including:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
    - Australian Paper Mills - 66/22 kV 32 MVA – T1
    - Byford -132/22 kV 32 MVA - T1
    - Cockburn Cement – 132/22 27 MVA - T1
    - Clarence street - 66/11 kV 27 MVA - T2
    - Collier - 66/11 kV 27 MVA -T1 and T3
    - Canning vale - 132/22 kV 30 MVA - T1 and T2
    - Gosnells - 132/22 kV 31.5 MVA - T2
    - Myaree - 66/22 kV 24 MVA - T1
    - O'Connor - 66/22 kV 27 MVA - T1 and T3
    - Pinjarra - 132/22 kV 15 MVA - T3

- Rockingham - 132/22 kV 32 MVA - T1 and T3
- Rivervale– 132/32 33.3 MVA - T3

- There are several 22 kV switchboards in the Belmont, Myaree and O'Connor zone substations which are in degraded condition and need to be addressed in the next 10 years.

14.4 Network Augmentation Works

Committed and completed transmission projects in the Metro South are shown in Table 30.

Table 30: Completed, committed, and proposed projects – Metro South Region

Project	Scope	Benefits of project	Network driver	By when	Lifecycle Status
Tate Street Substation: Decommission Substation	Offload Tate St zone Substation load to neighbouring zone substations and decommission the 66 kV substation assets.	Address the degraded asset condition of the existing T1 & T3 transformers	Asset condition	2022/2023	Execution
North Fremantle Substation: Decommissioning	The old 66 kV North Fremantle zone substation has been mostly de-energised since 2017. This works involves removing the degraded substation assets.	Remove the degraded and redundant 66 kV substation assets	Asset condition	2021/22	Completed
Kwinana 132 kV: New block load connection	Installation of a new 132 kV circuit from Kwinana to Leath Rd Substation and associated customer connection works.	Facilitate the connection of a new block load customer (28.5 MVA) in Kwinana.	Customer Driven	2022/23	Execution
Bibra Lake Substation: Additional transformer & load transfers	Installation of a third 132/22 kV 33 MVA transformer and distribution load transfers to facilitate the decommissioning of Australian Paper Mills Substation	Address existing substation capacity shortfall and address asset condition issues.	Growth – Thermal / Asset condition	2027/28	Initiation
Willetton Substation: Additional transformer & load transfers	Installation of a second 132/22 kV 33 MVA transformer and distribution load transfers to offload the Southern River Substation	Address existing substation capacity shortfall and accommodating increase demand in the area	Growth – Thermal	2027/28	Initiation
Waikiki Substation: Additional transformer & load transfers	Installation of a fourth 132/22 kV 33 MVA transformer and distribution load transfers to offload the Mandurah Substation	Address existing substation capacity shortfall and accommodating increase demand in the area	Growth – Thermal	2027/28	Initiation
Kwinana-Mandurah De-Meshing	A second 132 kV Rockingham to Waikiki circuit and 330/132 kV terminal transformer at Kwinana Terminal.	Facilitate the de-meshing of parts of the Metro South Region to alleviate a number of thermal and voltage capacity constraints.	Growth – Thermal	2027/28	Initiation
Byford Substation: Additional transformer & load transfers	Installation of a second 132/22 kV 33 MVA transformer and distribution load transfers to offload the Southern River Substation	Address existing substation capacity shortfall and accommodating increase demand in the area	Growth – Thermal	2024/25	Scoping

14.5 Network Opportunities

This section highlights network opportunities in the Metro South Region for the study period.

Table 31: Network Opportunities projects – Metro South Region

Project	Scope / Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Bibra Lake Substation: Additional transformer & load transfers	Installation of a third 132/22 kV 33 MVA transformer and distribution load transfers to facilitate the decommissioning of Australian Paper Mills Substation	To reduce demand in the area to eliminate, reduce of defer the need for additional transformer capacity.	2027/28	Initiation	9-12
Willetton Substation: Additional transformer & load transfers	Installation of a second 132/22 kV 33 MVA transformer and distribution load transfers to offload the Southern River Substation	Address existing substation capacity shortfall and accommodating increase demand in the area	2027/28	Initiation	9-12
Waikiki Substation: Additional transformer & load transfers	Installation of a fourth 132/22 kV 33 MVA transformer and distribution load transfers to offload the Mandurah Substation	To reduce demand in the area to eliminate, reduce of defer the need for additional transformer capacity.	2027/28	Initiation	9-12
Byford Substation: Additional transformer & load transfers	Installation of a second 132/22 kV 33 MVA transformer and distribution load transfers to offload the Southern River Substation	To reduce demand in the area to eliminate, reduce of defer the need for additional transformer capacity.	2024/25	Scoping	9-12
KW330 IMP 01, SF IMP 01 and CT IMP 01 available import capacity	Spare available import capacity exists over a number of import boundaries within the Metro South Region	An opportunity exists to utilise spare available capacity within the KW330 IMP 01, SF IMP 01, CT IMP 01 import boundaries by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a
KW330 EXP 01 available import capacity	Spare available export capacity exists within the KW330 EXP 01 boundary within Metro South Region	An opportunity exists to utilise spare available capacity within the KW330 EXP 01 export boundaries by connecting new generation.	Across the study period	n/a	n/a

14.6 Emerging Issues and Drivers

The 132 kV transmission network in the Metro South Region is highly meshed, which results in an over-utilised 132 kV network and under-utilised 330 kV network. Western Power is investigating options to de-mesh parts of the 132 kV network to improve efficiency and simplify power flows within and out of the region.

Western Power has received many enquiries regarding the connection of new generators and loads (mainly hydrogen facilities) in the Kwinana load area. Despite several constraints, particularly on the 132 kV networks, the 330 kV network in the Metro South Region is significantly under-utilised, presenting opportunities to support the connection of new loads and large-scale generation.

The progressive retirement of coal generation at Muja and Collie is expected to create significant changes and challenges in the area towards the end of the study period. These retirements are expected to result in a higher reliance on generation from Kwinana in the medium term, while over the longer term, gas-fired generation will also look to be retired.

Significant parts of the Metro South Region have major assets which are reaching the end of their life and need to be addressed. A number of 66 kV networks in this region (e.g., the South Fremantle, Cannington and Kwinana terminals) are anticipated to be either retired or upgraded to 132 kV as they approach their end of service life (within 10 to 20 years).

Western Power is working with industry to better understand how the proliferation of EVs will impact the network in the Metro South Region. Due to the high density of load in this region (particular along the river and in coastal areas), increased EV usage is likely to trigger the need to increase capacity on the transmission system. This may create challenges with service congestion, scarcity of available land, construction of new transmission lines and substations, as well environmental and community approvals.

15 East Perth and CBD Region

15.1 Geography

The East Perth and CBD Region covers the Perth CBD, the City of Subiaco and the City of Vincent. Figure 59 shows the transmission system in this region.

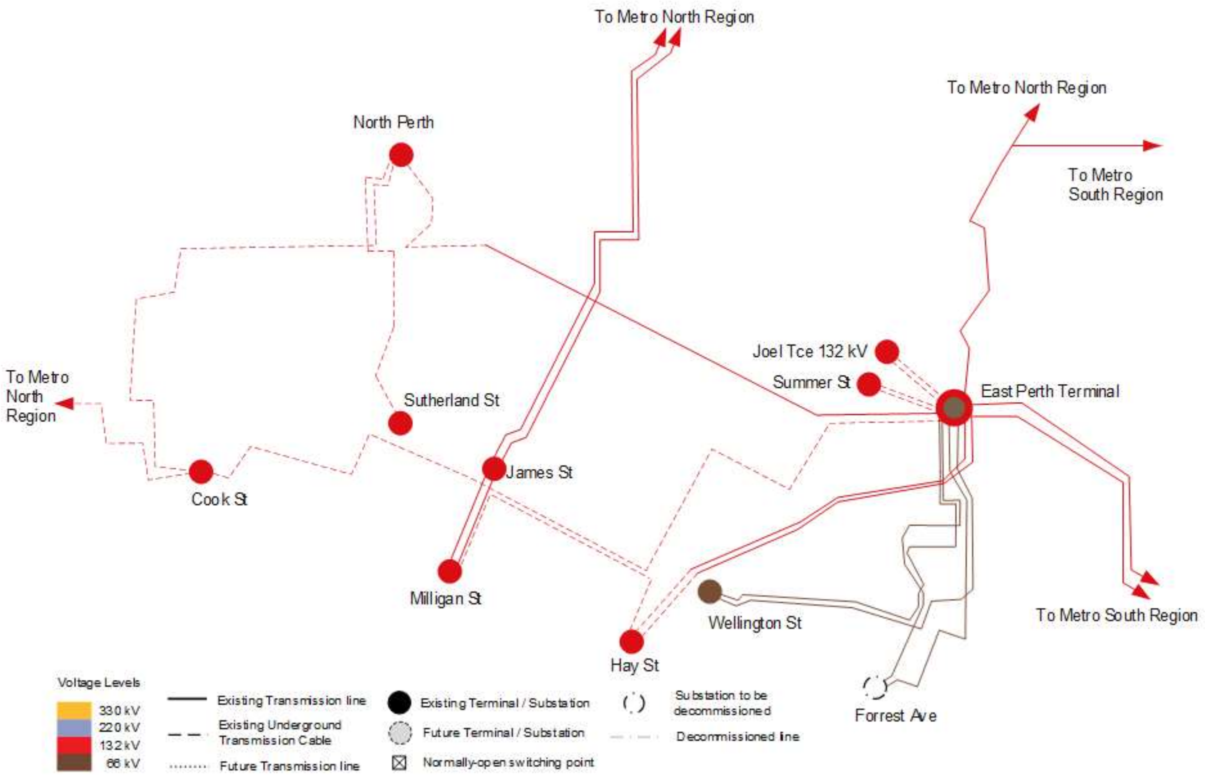

Figure 59: Western Power's East Perth and CBD Region – Network Diagram

The East Perth and CBD Region features one terminal (East Perth) and seven zone substations that are owned and operated by Western Power. The other transmission sites in this region are customer-owned substations.

<u>**Terminals**</u>

- East Perth Terminal – 132/66 kV

<u>**Zone Substation / WP Substations**</u>

- Cook Street – 132/11 kV
- Forrest Ave – 66 kV
- Joel Terrace – 132/11 kV[44]
- Hay Street– 132/11 kV
- Milligan Street – 132/11 kV
- North Perth – 132/11 kV
- Wellington Street – 66/11 kV

<u>**Customer Substations**</u>

- Summer Street (PTA)– 132/11 kV

44 The Forrest Ave 66kV substation is still energised however the transformers are removed and load is transferred to neighbouring substations.

15.2 Regional Characteristics

15.2.1 General

The East Perth and CBD Region is characterised by the densely populated areas of West Perth, East Perth, and the CBD. The customers in the region consist of a mixture of commercial, retail and residential. The region also supports a Public Transport Authority (PTA)-owned substation used to supply rail infrastructure.

Despite several recent major developments in the East Perth and CBD Region, the peak demand levels are forecast to decline over the period. This trend has largely been driven by changing work behaviours that have reduced the demand, particularly in the Perth CBD zone.

15.2.2 Generation

There is no notable generation connected within the East Perth and CBD Region and no generation forecast to be connected within the study period.

15.2.3 Existing Transmission Network Supply

The East Perth and CBD Region is centred on the East Perth Terminal, which delivers power to densely populated areas of West Perth, East Perth and the CBD via seven zone substations and 132 kV and 66 kV sub-transmission networks.

Given the centralised, high-density nature of the load power predominately flows into the Region from neighbouring North and Metro North regions via the Northern and Western terminals to the north and from the Metro South Region via the Southern and Cannington terminals from the south. Although less likely as more generation is connected in the North Region, power transfer can go from the East Perth Terminal to the Northern Terminal under lightly loaded conditions, particularly with minimal generation operating in the North Region.

Supply into the region comes from two 132 kV cables that cross the Swan River via the Graham Farmer Freeway, connecting the Southern Terminal (Metro South Region) and the East Perth Region. There are also 132 kV transmission line/cables between the Western Terminal (Metro North Region) and Cook Street Substation, and a transmission line from Belmont Substation out of Cannington Terminal (Metro South Region) which forms a tee line with a 132 kV circuit connecting East Perth to the Northern Terminal (North Region). For more effective control of power flows into the region, the Belmont end of this tee line predominately operates as normally open. Two 132 kV circuits from the Northern Terminal (North Region) also support a significant portion of CBD substation load at Milligan Street Substation via Mount Lawley.

The transmission lines in this region are generally designed to meet the N-1 capacity criteria, with the exception of supply capacity into Hay Street and Milligan Street which is designed to the Perth CBD N-2 criterion to cater for the increase security of supply reinforcements.

15.2.4 Key Developments In the Region

Over the past 5 to10 years, the East Perth and CBD Region has undergone transformational changes including Elizabeth Quay, Perth City Link, Riverside and the NextDC data centre. These developments have all been given supply, however increases in load for many of these customers is expected to be gradual as construction of the sites develops.

Despite many recent major load developments in the East Perth and CBD Region, peak demand levels are forecast to decline over the period. This trend has largely been driven by flexible and remote working arrangements that have become more common since the COVID-19 pandemic, with the Perth CBD zone experiencing the greatest level of impact.

In late 2018, the State Government announced plans to redevelop the East Perth Power Station and the adjoining land owned by Main Roads. Western Power was asked to investigate costs and an earliest feasible delivery date for the following works to facilitate the redevelopment:

- decommissioning the 66 kV assets East Perth 66 kV Substation.
- undergrounding the 132 kV overhead transmission line in the foreshore area of the site.

The above has also triggered works to decommission the 66 kV Forrest Avenue and Wellington Street substations and their 66 kV supplies. Western Power is working towards completing all related works to facilitate redevelopment of the site by 2024.

15.3 Network Performance

This section presents the network performance for the East Perth and CBD Region over the study period.

15.3.1 Thermal Capacity - Boundaries

The following assumptions were made in developing the import and export boundaries:

- Import boundaries consider peak demand and economic generation dispatch conditions.

Import Boundary

Figure 60 shows the network import boundaries in the East Perth and CBD Region. These boundaries are defined using the worst contingency (⚡) and the worst overload circuit (*) as shown in Table 32 .

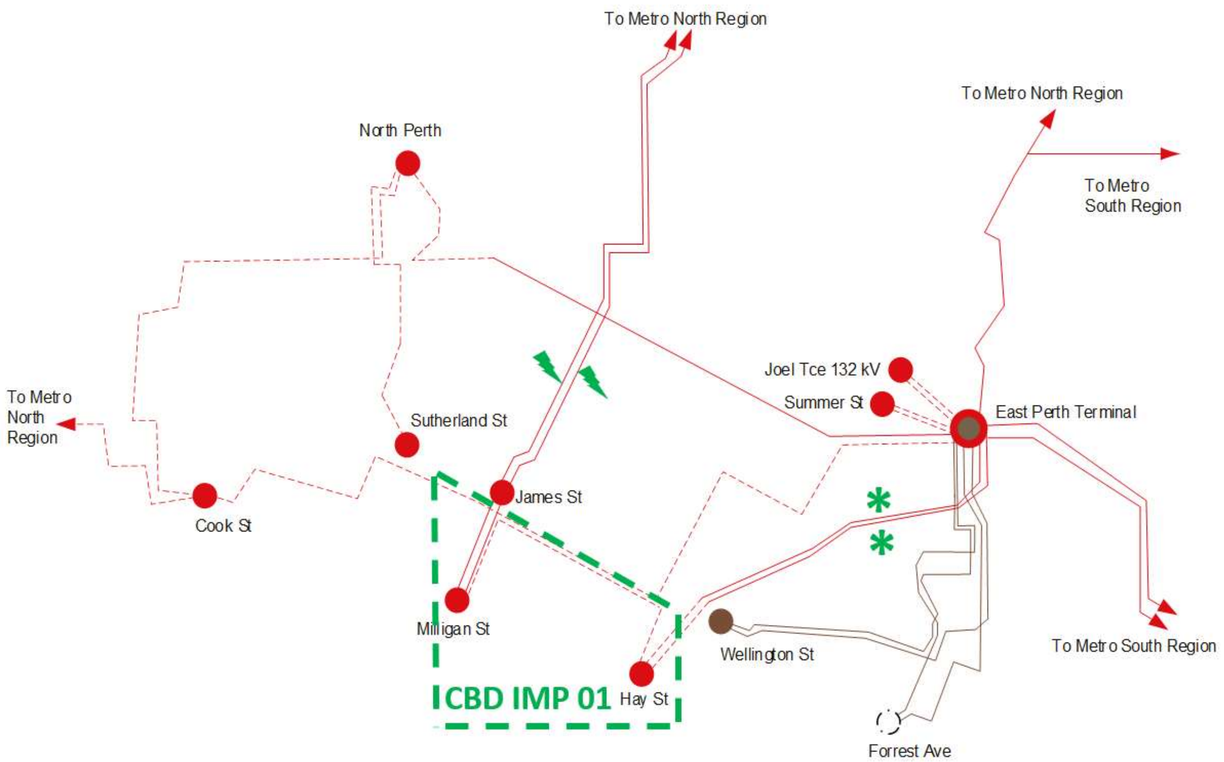

Figure 60: Network import boundaries in the East Perth and CBD Region

Table 32: Thermal import boundary characteristics – East Perth and CBD Region

Characteristics	Import Boundary
	CBDIMP 01
Worst contingency	Mount Lawley to Milligan St 81 and Mount Lawley to Milligan St 82
Contingency type	N-2
Worst circuit/s	East Perth to Hay St 81 and East Perth to Hay St 82

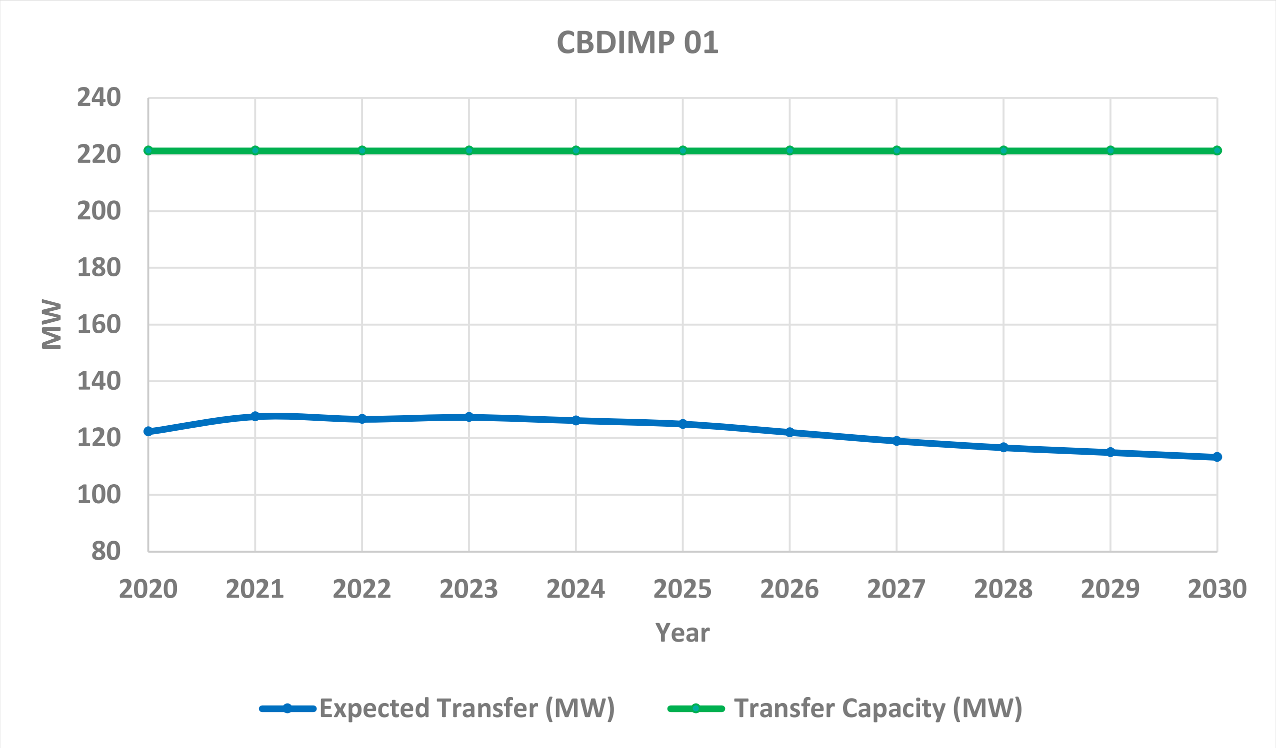

Figure 61: Expected transfer and transfer capacity in CBDIMP 01 boundary – peak demand

As observed in Figure 61, there is about 100 MW of available transfer capacity into the CBDIMP 01 boundary over the study period during system peak demand conditions. The transfer capacity into this import boundary is currently limited by the sections of underground cable on the East Perth to Hay 81/82 circuits located between the Wellington Street and Hay Street zone substations that are lower in rating than the overhead sections of the supplies into the Hay Street zone substation.

15.3.2 Thermal Capacity – Transmission Lines

The expected transfers within the East Perth and CBD Region fall withing the N-1 transfer capacity over the study period.

15.3.3 Thermal Capacity – Zone Substation Transformers

This section shows the existing and forecast peak load utilisation across the period 2020/21 to 2029/30 for all zone substations operated by Western Power within the East Perth and CBD Region.

Table 33: Utilisation legend (for Table 34)

LEGEND	Classification Name	Utilisation %
	Under utilised	below 40%
	Medium utilisation	>40% & 75%
	Highly utilised	>75% & 95%
	Over utilised	above 95%

Table 34: East Perth and CBD Region Zone Substation utilisation heat map

Substation	Sub Capacity MVA	Actual Utilisation (%)	Forecast Utilisation (%)																				Comment
		2020	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		
			PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	PoE 10	PoE 50	
Cook St	81	73	83	73	81	71	80	69	78	68	77	67	76	66	75	65	74	64	73	63	72	62	Additional transformer (Scoping, RIS year 2024),
Forrest Ave	39	67	72	68	70	65	67	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Forrest Ave Substation retirement and load transfers to Hay St and Joel Terrace Substations (Execution, RIS year 2023),
Hay St	143	52	47	42	47	41	55	46	54	45	54	44	53	42	53	41	53	39	53	38	53	36	Load transfers from Forrest St and (Execution, RIS year 2023) Wellington St Substations (Scoping, RIS year 2024)
Joel Terrace	76	41	41	37	40	35	79	71	77	68	75	66	72	63	70	60	68	57	65	55	63	52	Load transfers from Forrest St (Execution, RIS year 2023) and Wellington St Substations (Scoping, RIS year 2024)
Milligan St	134	51	54	52	51	49	53	51	51	48	49	46	46	43	44	41	41	39	39	36	37	34	
North Perth	77	71	71	64	71	64	74	66	73	66	73	65	72	65	72	65	71	65	71	64	71	64	
Wellington St	29	109	92	79	90	78	89	76	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Load transfers to Hay, Milligan and Wellington St Substations (Scoping, RIS year 2024)

15.3.4 Steady State Voltages

There are no voltage-related performance issues in the East Perth and CBD Region within the study period.

15.3.5 Fault Levels

Existing fault level performance constraints were identified in the East Perth and CBD Region within the study period, including:

- A total of eight Mount Lawley Substation 132 kV isolator switches are marginally under fault rated during peak demand conditions. Western Power is replacing two of the isolators with condition issues, while the risk associated with the remaining isolators will be managed by operating the 132 kV bus at the Mount Lawley Substation under a split arrangement to reduce fault levels.

15.3.6 Stability

There are no stability-related performance constraints within the East Perth and CBD Region over the study period.

15.3.7 Reliability

There are no reliability-related performance constraints within the East Perth and CBD Region over the study period.

15.3.8 Asset

Existing asset performance constraints identified in the East Perth and CBD Region within the study period include:

- A number of zone and terminal substation transformers in degraded condition require mitigation within the study period, including:
  - East Perth Terminal – 132/66 KV 100 MVA – T3 and T5
  - Forrest Ave – 66/11 KV 20 MVA – T1 and T2
  - Wellington Street – 66/11 KV 20 MVA – T1 and T2
- The 11 kV switchboards at the Hay Street, Milligan Street, and Forrest Avenue substations are in degraded condition and require mitigation in the next 10 years.
- A large portion of the 66 kV overhead structures and underground cables have less than 10 years remaining service life. In particular, the following underground cables have oil leaks occurring at an increasing rate. These cables present a risk to security of supply, along with posing environmental risks associated with oil leakage.
  - East Perth to Wellington St 71 – 1.8 km
  - East Perth to Wellington St 72 – 2.6 km
  - East Perth to Hay St 81 – 0.6 km
  - East Perth to Hay St 82 – 0.7 km

15.4 Network Augmentation Works

Committed, completed and proposed transmission projects in the East Perth and CBD Region are shown in Table 35.

Table 35: Completed, committed, and proposed projects – East Perth and CBD Region

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Hay/Milligan St 132 kV: Supply Reinforcement	A new 132 kV cable is installed between Hay Street and Milligan Street Zone Substations.	• Increase power transfer capability in the CBD under N-2 conditions • Facilitate the decommissioning of the Forrest St and Wellington St Substations, which are partially transferred to Hay St and Milligan St Substations.	Growth – Thermal / Asset condition	2021/22	Completed
Hay St Substation: Switchboard refurbishment	The indoor 11 kV switchboard at Hay Street zone Substation is refurbished.	• Address degraded asset condition issues • Maintain the expected service life	Asset condition	2020/21	Completed
Milligan St Substation: Switchboard refurbishment	The indoor 11 kV switchboard at Milligan Street Zone Substation is refurbished.	• Address degraded asset condition issues • Maintain the expected service life	Asset condition	2021/22	Completed
Forrest St Substation: Decommissioning	The Forrest Avenue Zone Substation and associated 66 kV supply lines are to be decommissioned.	• Facilitate the redevelopment of the East Perth Power Station site. • Address multiple degraded 66 kV asset condition issues at Forrest Ave and Wellington St Substations • New Cook St transformer and distribution feeders will provide additional operational flexibility to support planned and unplanned outages in the Perth CBD. • Installation of a protection inter-trip scheme to facilitate the parallel operation of the new 132 kV Hay-Milligan St cable	Customer Driven /Asset condition	2022/23	Execution
East Perth Redevelopment	Undergrounding parts of the East Perth to Hay 132 kV circuits to facilitate the East Perth Power Station redevelopment.			2022/23 & 2023/24	Planning
Wellington St Substation: Decommissioning	The 66 kV power transformers and supply lines into Wellington St Substation are to be decommissioned. In addition, the installation of a new 66 MVA Cook St transformer, along with four distribution feeders to the Wellington 11 kV switchboards.			2023/24	Scoping

15.5 Network Opportunities

This section highlights network opportunities in the East Perth and CBD Region over the study period.

Table 36: Network Opportunities projects – East Perth and CBD Region

Project	Scope / Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
Wellington St Substation: Decommissioning	The 66 kV power transformers and supply lines into Wellington St Substation are to be decommissioned. In addition, the installation of a new 66 MVA Cook St transformer, along with four distribution feeders to the Wellington 11 kV switchboards	To defer or completely offset the need to install a third Cook St 66 MVA transformer by reducing the demand supplied by the Hay St and Milligan St Substation, particularly during peak demand conditions.	2022/23	Scoping	~36.2
CBD IMP 01 available import capacity	Spare available import capacity exists over a number of import boundaries within the East Perth and CBD Region.	An opportunity exists to utilise spare available capacity within the CBD IMP 01 import boundary by increasing demand of existing loads or via the connection of new loads	Across the study period	n/a	n/a

15.6 Emerging Issues and Drivers

Significant network investment within the East Perth and CBD Region has recently been completed and committed to address the risks associated with ageing 66 kV asset infrastructure. Although these works involved a consolidation of major assets, the East Perth and CBD Region has sufficient spare capacity to meet the expected transfers within the region over the study period.

Despite recently completed works involving the refurbishment of the Hay Street and Milligan Street 11 kV switchboards, these assets are expected to require replacement within the next 20 years. Both Hay Street and Milligan Street buildings are more than 40 years old, presenting challenges in maintaining security, compliance with modern standards and reliability of supply while replacing or refurbishing major assets that are nearing their end of asset life.

Over the longer term, demand uncertainty around electrification of vehicles at high levels is likely to present major challenges for the region. Western Power is working with industry to better understand how these changes will impact the network in the region, with a number of new zone substations and supply lines anticipated to meet potentially large increases in demand.

Due to limited access points across the Swan River, service congestion and scarcity of available land, construction of new transmission lines and substations in the region is likely to be difficult. Furthermore, the construction of new transmission lines and zone substations in the area will face challenges in gaining environmental and community approvals, incurring significant expenditure associated with construction and planning. As such, reinforcements in the region inherently incur higher project costs.

16 System Wide Constraints

16.1 System Low Issues

The SWIS is experiencing an unprecedented transition in the way that electricity is supplied and consumed. The increased integration of renewable generation has led to major changes to both ends of the electricity supply chain. The level of rooftop PV connections connected to the SWIS has increased significantly, with more than 2,000 MW of inverter capacity now connected and high growth rates of new DPV connections forecast over the next five years. High levels of PV capacity and output have resulted in a number of challenges in managing power system security and reliability during periods of low operational demand, particularly during daytime periods where rooftop PV output is high. In response to these growing risks, the State Government announced its Energy Transformation Strategy, detailing its response to the energy transformation underway and the plan for the future of the State's power system. Additionally, the Low Load Project was raised to undertake analysis and quantify emerging risks to power system security during periods of low operational demand and to ensure appropriate responses, frameworks and mechanisms are in place and available to maintain power system security. The Low Load Project is led by EPWA, with collaboration from Western Power and AEMO.

The following works packages were created to investigate and quantify emerging risks:

- **Distributed Energy Resources (DER) Performance** – DPV disconnects or reduces output in response to power system disturbances (i.e., voltage disturbances and /or frequency disturbances), resulting in increasing contingency sizes. The objective of this works package involves identifying the extent of 'at risk' PV for critical contingencies.
- **Frequency Stability** – maintained when a single contingency does not result in an Under Frequency Load Shedding (UFLS) event. This includes considering the inertia provided by dispatched generation, available spinning reserve, managing the size of the largest contingency, and the amount of DPV disconnection too. Given forecasts for load and DPV, this works package aims to determine the timing, extent and sensitivities around frequency stability issues in the short term (i.e., six months to two years) and long term (i.e., two years or more).
- **UFLS** – increased levels of DPV are resulting in a reduction of net load available for load shedding, thus reducing the effectiveness of the UFLS scheme to arrest the system frequency decline following a multiple contingency event. This works package involves a comprehensive review of the performance of the current design of the UFLS system, particularly in a high DER environment.
- **System Strength** - system strength relates to the ability of a power system to withstand changes in generation output and load levels while maintaining stable voltage levels. If system strength is too low, non-synchronous generation may not be able to operate in a stable manner. This works package aims to investigate system strength at locations in the network where it is suspected to be low.
- **Wide Area Monitoring Protection and Control (WAMPAC)** - WAMPAC provides near real-time network data back to the Real Time Simulator (RTS) for continuous model improvement. WAMPAC can perform real-time measurement and calculations to optimise the management and operation of the power system. This works package involves scoping of WAMPAC trials at selected locations to inform potential larger scale and progressive rollout.

While works are ongoing, a number of key findings include:

- Better understanding of the extent and timing of the system low issues.
- A Minimum Demand Threshold (MDT) range developed to ensure frequency stability can be maintained. To cater for this risk in the short term, operating protocols have been updated to

schedule additional generators during low operational periods, increasing the amount of spinning reserve to maintain frequency stability and avoid UFLS. Additionally, some generators may be dispatched at lower outputs.

- The magnitude of a credible contingency size (which includes the impact of unintentional DPV disconnection) has been identified, with actions already undertaken to cater for increased risk.
- The performance of the current design of the UFLS system remains effective when the target UFLS requirement of 15 per cent per stage is maintained. However, historical average load shedding levels are significantly lower, with system study results highlighting contingency sizes to trigger UFLS stages and frequency collapse reduced on average by up to 20 per cent. This increased level of system security risk triggered an emergency project to increase load shedding reserves by connecting a number of transmission customers to the UFLS.
- The outcome of initial system strength studies highlighted no major issues across the SWIS.

In addition to the projects proposed throughout sections 10 to 15, Western Power has developed a number of programs of work to target issues that are experienced throughout the transmission system and are not specific to any one particular Region.

The majority of the program of works targets voltage, reliability and power quality issues on the transmission network.

Table 37: Completed and committed projects

Project	Scope	Benefits of project	Network driver/s	By when	Lifecycle Status
Voltage Management Program - Stage 1 and 2	Installation of a series of reactor banks, totalling 350 MVAr on the transmission and distribution networks.	Provide flexibility to manage voltages and reactive reserve margins during periods of low operational demand.	Growth - Voltage	2020/21 to 2021/22	Completed
SWIS UFLS Issues Management	Protection upgrade works across a number of zone substations to increase the level of remote UFLS telemetry and reverse blocking capability of UFLS loads.	• Increase the level of UFLS load shedding availability to maintain the UFLS performance levels and system security risks, particularly during daytime minimum demand periods. • Add capability to block UFLS loads that are experiencing reverse powerflows, to avoid exacerbating an UFLS event.	Growth - Stability	2022/23	Execution
Transmission UFLS – Temporary solution	The connection of a number of existing transmission load connections to the UFLS scheme under an emergency pathway via a temporary UFLS solution.	Rapidly increase the level of UFLS load shedding availability to maintain the UFLS performance levels and system security risks, particularly during daytime minimum demand periods. This solution provides limited remote monitoring and control capability and is only intended to be a temporary solution.		2022/23	Execution
Transmission UFLS – Long-term solution	Upgrading the transmission load customers connected to UFLS with enhanced capability, including remote control (stage selection) and monitoring.	Together with input from customers, the temporary UFLS connections will be upgraded with enhanced functionality that provides redundancy and remote monitoring and control capability. This increased functionality will provide greater flexibility in managing the UFLS load reserves and meeting the UFLS design requirements.		2023/24	Scoping

Dynamic UFLS Management system	Installation of a dynamic UFLS management system	A dynamic UFLS management system is a control system that is designed to automatically manage and optimise the portfolio of available UFLS load shedding reserves in accordance with the current UFLS design requirements.		2023/24	Scoping
Trial Project: Installation of load banks	Installation of 6 x 5 MVAr of load banks at various substations.	Provide stable load to support restarting the power system in the event of system wide outages.		2023/24	Scoping

16.2 Network Opportunities

This section highlights the opportunities for network constraints on a SWIS level over the study period.

Table 38: Network Opportunities

Project	Scope / Issue	Market Opportunity	By when	Lifecycle Status	Estimated Network Solution Cost ($M)
n/a	n/a	To reduce a number of impacts that arise during periods of low operational demand, an opportunity exists to increase or shift demand patterns during the during the daytime periods (10AM to 3PM) when the rooftop PV output is at high. The opportunity is available throughout the year but is greater in the high-risk spring and autumn periods.	Across the period	n/a	Yet to be quantified

17 Market Impacts of Network Congestion

17.1 Overview

The WEM is currently operated under an unconstrained network access framework where generators must fund network augmentations to maintain the unconstrained access of incumbents. In recent years, interim arrangements including runback schemes and Generator Interim Access (GIA) have allowed generators to avoid funding augmentations by agreeing to reduced levels of access. Since June 2020, five generators have been connected under GIA arrangements. This scheme pre-contingently curtails the output of these generators to manage potential N-1 network thermal overloads. As these customers connected to the SWIS under a non-reference service, they do not receive any constrained-off payments in the WEM. In the absence of a direct market cost of network constraints the estimated cost of GIA curtailment is, although rudimentary, the closest proxy to the cost of network constraints[45].

However, when the new security-constrained economic dispatch market commences in October 2023, the cost of binding network constraints will be reflected in energy uplift payments made to generators to relieve network constraints. The cost of these uplift payments and other relevant information such as the location, magnitude and frequency of binding network constraints will be used in future TSPs to determine the point at which network augmentation becomes more economically efficient when compared with dispatching expensive generators in the market.

17.2 Methodology and Results

For the purposes of estimating market impact, Western Power estimated the cost of curtailing generators that are subject to GIA arrangements. Historical GIA operational data was used to estimate the cost of curtailment as follows:

- Total energy curtailed (MWh) x Final balancing price ($/MWh)

The total energy curtailed under GIA and the final balancing price information was obtained from AEMO's publicly available dashboard data[46]. Data was extracted from the commencement of GIA to the end of the 2021/22 financial year.

Estimated network congestion costs are shown in **Error! Not a valid bookmark self-reference.**. The estimated cost to the market for the past financial year was approximately $4.27M, with a total of $7.07M since the commencement of GIA[47].

Table 39: Estimated network congestion costs due to GIA constraints

Data Range	Estimated Cost ($ millions)
1/4/21 to 30/6/2022	7.07
30/6/21 to 30/6/2022	4.27

45 Other sophisticated analyses such as a counterfactual dispatch merit order if no GIA constraints existed, may be possible for future TSPs within time and resource constraints.

46 https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/data-dashboard#market-diversification-generation

47 Costs are expected to be even lower as the renewable GIA generators typically bid into the balancing market at a price lower than the final balancing price

This analysis clubs all GIA generators together to produce an overall proxy cost of network constraints. In the absence of the security-constrained dispatch algorithm, it is not possible to know whether these constraints were binding and would have to be resolved by constraining other generators at a higher cost. As such, this analysis cannot be relied upon to estimate an economic cost of network congestion to compare with cost of network augmentation.

Appendix A: Our Operating Environment

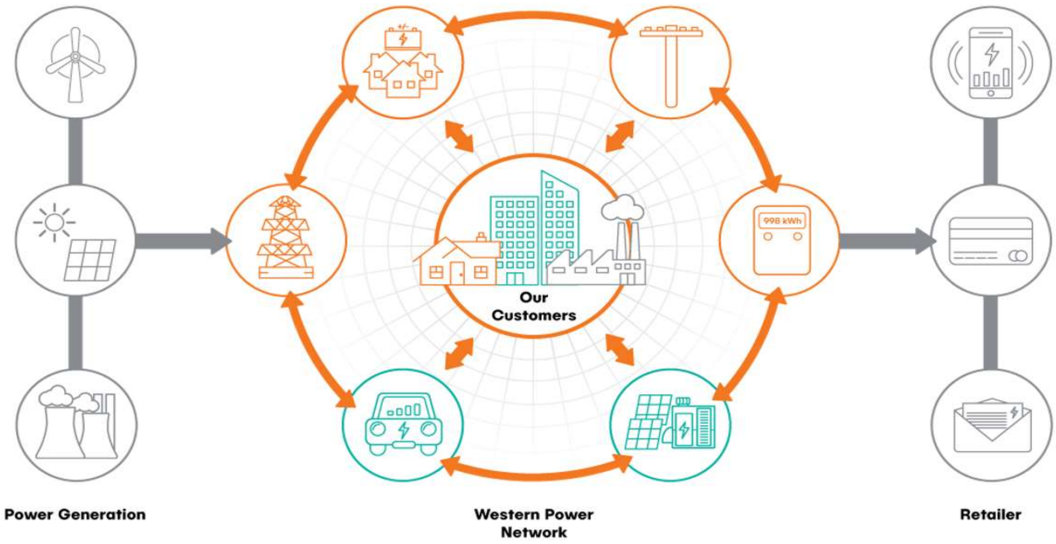

Figure 62: Western Power's role within the Western Australia's electricity market

Western Power is a Western Australian State Government owned corporation responsible for building, maintaining and operating an electricity network. It is licenced under the Electricity Industry Act 2004 (Act) and regulated by the Economic Regulation Authority (ERA), which grants the Electricity Transmission Licence (ETL2) and Electricity Distribution Licence (EDL1) and determines Western Power's revenue, services, policies and incentives via the access arrangement (AA). The network facilitates the Wholesale Electricity Market (WEM) which is operated by the Australian Energy Market Operator (AEMO).

These laws and regulations govern all aspects of our operations, from how funding for works is obtained, to standards of supply and tariff structure. For more information, visit the Energy Policy WA (EPWA) website[48].

48 https://www.wa.gov.au/organisation/energy-policy-wa/regulatory-framework

Appendix B: System Study Modelling Data

This section highlights the key modelling inputs for developing the peak and minimum demand scenarios. Although Western Power and AEMO perform system studies over a wider range of sensitivity scenarios to cover uncertainties in demand and to refine investment timing triggers, system studies presented in the inaugural TSP reflect an efficient and likely generation dispatch for each demand scenario.

B.1 System demand levels

A breakdown of the peak and minimum demand levels used for performing system studies across the study period are shown in Table 40 and Table 41.

Table 40: Breakdown of system demand used for system studies – peak demand

	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Total Load Demand (MW)	4874	4897	4882	4856	4855	4850	4850	4856	4860	4864
Generator Auxiliary Load (MW)	100	100	92	92	84	84	84	84	84	84
HV Customer (MW)	600	586	585	584	584	584	584	582	582	581
Imbedded Generator Site Load (MW)	520	520	520	520	520	520	520	520	520	520
Normal Substation LV (MW)	3654	3691	3685	3660	3667	3663	3663	3670	3675	3679
Sub-Total Load Demand (excl. Imbedded) (MW)	4354	4377	4362	4336	4335	4330	4330	4336	4340	4344
No. of Synchronous Market Scheduled Units	35	34	39	38	40	40	40	40	40	40

Table 41: Breakdown of system demand used for system studies – minimum demand

	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Total Load Demand (MW)	1404	1327	1252	1172	1091	1009	927	839	758	709
Generator Auxiliary Load (MW)	24	23	23	23	23	23	22	17	17	22
HV Customer (MW)	451	446	451	452	454	456	457	459	461	463
Imbedded Generator Site Load (MW)	416	416	416	416	416	416	416	416	416	416
Normal Substation LV (MW)	512	442	362	281	198	115	32	-53	-137	-192
Sub-Total Load Demand (excl. Imbedded) (MW)	**988**	**911**	**835**	**756**	**675**	**593**	**511**	**423**	**341**	**293**
No. of Synchronous Market Scheduled Units	12	10	8	8	8	8	8	7	6	6

B.2 Generator dispatch profiles

A breakdown of the peak and minimum demand levels used for performing system studies across the study period are shown in Table 42 and Table 43.

Table 42: Breakdown of generator dispatch profile used for system studies – peak demand

MW Dispatch Level (MW) (To be dispatched at >= Pmin value)	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Total Generation (MW)	**5001**	**5034**	**5012**	**4985**	**4980**	**4975**	**4980**	**4983**	**4987**	**4991**
Total Synch. Market Scheduled demand (MW)	4243	4276	4254	4227	4222	4216	4221	4225	4229	4233
No. of Synchronous Market Scheduled Units	35	34	39	38	40	40	40	40	40	40
ERRRF_WTE	0	28	28	28	28	28	28	28	28	28
GEN_KBA_GT	46	46	46	46	46	46	46	46	46	46
Gen_APJ_GT1 & GT2	284	284	284	284	284	284	284	284	284	284
Gen_AWG_GT1 & GT2	360	360	360	360	360	360	360	360	360	360
Gen_BWP_G1 & G3	217	217	217	217	217	217	217	217	217	217
Gen_CKB_GT1 & SG1	237	237	237	237	237	237	237	237	237	237
Gen_CPS_G1	329	328	323	329	329	329	329	329	329	329
Gen_GNN_GT11 & GT12	331	331	331	331	331	331	331	331	331	331
Gen_KMK_GT1	34	34	34	34	34	34	34	34	34	34
Gen_KMP_GT1 & GT2	244	294	302	302	302	302	302	302	302	302
Gen_KND_GT1 & GT2	101	101	101	101	101	101	101	101	101	101
Gen_KNS_GT2	46	46	46	46	46	46	46	46	46	46
Gen_KPP_GT1, GT2 & SG1	81	0	0	0	0	0	0	0	0	0
Gen_MDP_G1 & G2	0	0	0	0	73	67	72	75	80	78
Gen_MPS_G5, G6, G7, G8	800	800	780	780	580	400	400	400	400	400
Gen_NGK_GT3 & SG3	324	324	324	324	324	324	324	324	324	324
Gen_PJR_GT1 to GT8	0	0	175	142	194	194	194	194	194	194
Gen_PJR_GT9, GT10 & GT11	331	331	331	331	331	331	331	331	331	331
Gen_PRK_GT1 & GT2	64	64	64	64	64	64	64	64	64	64
KW_HEGT_G2 & G3	128	128	128	198	198	198	198	198	198	198
KW_WTE	0	37	37	37	37	37	37	37	37	37
Renewable Generation (MW)										
CGW - Collgar Wind Farm	75	75	75	75	75	75	75	75	75	75
YDW - Yandin Wind Farm	72	72	72	72	72	72	72	72	72	72
WDW - Warradarge Wind Farm	61	61	61	61	61	61	61	61	61	61

WWF - Walkaway Wind Farm	31	31	31	31	31	31	31	31	31	31
EMD - Emu Downs	27	27	27	27	27	27	27	27	27	27
MRS - Merredin Solar Farm	22	22	22	22	22	22	22	22	22	22
MBA - Mumbida Wind Farm	21	21	21	21	21	21	21	21	21	21
GRS - Greenough River Solar Farm	8	8	8	8	8	8	8	8	8	8
AWF - Albany Wind Farm	7	7	7	7	7	7	7	7	7	7
BGA - Badgingarra Wind Farm	6	6	6	6	6	6	6	6	6	6
GWF - Grasmere	5	5	5	5	5	5	5	5	5	5
Distribution PPGs	26	26	26	26	26	26	26	26	26	26

Table 43: Breakdown of generator dispatch profile used for system studies – minimum demand

MW Dispatch Level (MW) (To be dispatched at >= Pmin value)	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
Total Generation (MW)	**1424**	**1347**	**1271**	**1191**	**1110**	**1027**	**945**	**858**	**777**	**729**
Total Synch. Market Scheduled demand (MW)	867	790	714	634	553	525	443	356	302	254
No. of Synchronous Market Scheduled Units	12	10	8	8	8	8	8	7	6	6
Gen_APJ_GT1	85.6	85.6	85.6	65.0	50.0	30.0	30.0	30.0	30.0	30.0
Gen_APJ_GT2	88.6	88.6	88.6	65.0	50.0	30.0	30.0	30.0	30.0	30.0
KW_HEGT_G2	25.0	25.0	60.0	50.0	50.0	50.0	40.0	40.0	40.0	40.0
KW_HEGT_G3	59.3	59.2	59.2	50.0	50.0	50.0	40.0	40.0	40.0	40.0
Gen_PJR_GT11	73.1	73.1	73.1	73.1	70.0	70.0	40.0	40.0	40.0	30.0
Gen_PJR_GT10	70.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen_BWP_G2	126.9	128.6	119.9	110.7	108.5	115.2	98.1	93.7	122.2	83.7
Gen_BWP_G1	123.3	115.8	120.0	110.0	105.0	110.0	100.0	82.0	0.0	0.0
Gen_MPS_G7	124.1	124.1	107.7	110.3	70.0	70.0	65.0	0.0	0.0	0.0
Gen_KMK_GT1	20.3	20.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen_KPP_GT1	35.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gen_KPP_GT2	35.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Generation (MW)										
EDWFMAN_WF1	9.3	9.3	9.3	9.3	9.3	0.0	0.0	0.0	0.0	0.0
EDWFMAN_WF2	9.3	9.3	9.3	9.3	9.3	0.0	0.0	0.0	0.0	0.0
ALINTA_WWF	20.9	20.9	20.9	20.9	20.9	0.0	0.0	0.0	0.0	0.0
MWF_MUMBIDA_WF1	14.2	14.2	14.2	14.2	14.2	0.0	0.0	0.0	0.0	0.0

B.3 Network Configuration Assumptions

A breakdown of the peak and minimum demand levels used for performing system studies across the study period are shown in Table 44.

Table 44: Breakdown of generator dispatch profile used for system studies – minimum demand

	Peak Demand	Minimum Demand
Northern Terminal to Muja 330 kV (Muja end)	Close	Open
Northern Terminal 132 kV busbar status	Open/Split Bus	Close/Parallel Bus
Northern Terminal T2 status	In Service	In Service
Mount Lawley 132 kV busbar status	Open	Close
Belmont – Northern Terminal/ East Perth 132 kV line (Belmont end)	Open	Open
Wagin - Narrogin South/Narrogin (Narrogin South/Narrogin ends)	Open	Open
Cunderdin – Kelleberin 66 kV (Kelleberin end)	Open	Open
Kemerton-Busselton-Picton/Pinjarra 132 kV line (Picton end)	Open	Open
South Fremantle – Southern Terminal 132 kV & Southern Terminal- Kwinana 132 kV (at Southern Terminal end)	Close / Without Bypassing Southern Terminal	Close / Without Bypassing Southern Terminal
Southern Terminal – Kwinana 132 kV line	Open	Close
Hay – Milligan 132 kV cable (at Milligan end)	Open	Open

Appendix C: Estimated Maximum/Minimum Short Circuit Levels

Per the requirements under clause 5.5.1 b) of the Technical Rules, this appendix provides the existing and five-year forecast maximum and minimum short circuit levels at each of the Western Power network's major transmission nodes. This information will allow existing and future users to procure, design and operate their equipment within the expected maximum and minimum short circuit (or fault) levels at their connection point.

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. For minimum fault levels, the C factor is set at 1.0 pu.
- Zero fault impedance is assumed.
- For maximum fault levels, all generation machines and step-up transformers are turned on.
- All lines are in service.

The expected fault current shown is I_{KSS}.[49]

Table 45: Maximum fault levels

		Current Levels (0 years)		Future Levels (5 years)	
Substation	**Voltage (kV)**	**Fault level 3-phase (kA)**	**Fault level 1-phase (kA)**	**Fault level 3-phase (kA)**	**Fault level 1-phase (kA)**
East Region					
BDE - Bandee	66	1.9	1.6	1.8	1.6
BKF - Black Flag	132	2.6	2.8	2.6	2.8
BLD - Boulder	132	4.8	5.8	4.8	5.8
BNY - Bounty	132	0.7	0.9	0.7	0.9
CAR - Carrabin	66	1.3	1.0	1.3	1.0
CGT - Collgar Terminal	220	3.4	4.5	3.4	4.5
CGW - Collgar Wind Farm	220	3.4	4.5	3.4	4.5
CUN - Cunderdin	66	1.1	0.8	1.1	0.8
JAN-Jan	132	2.0	2.1	2.0	2.1
KDN - Kondinin	220	3.1	2.9	3.1	2.9
KDN - Kondinin	132	1.5	1.7	1.5	1.7
KEL - Kellerberrin	66	1.2	0.9	1.2	0.9
LEF-Lefroy	132	2.2	2.5	2.2	2.5
MDP - Merredin Power Station	132	6.2	8.4	6.2	8.4
MER - Merredin	66	3.9	5.3	3.9	5.3
MER - Merredin	132	5.3	6.4	5.3	6.4
MRS - Merredin Solar Farm	220	3.8	5.0	3.7	5.0
MRT - Merredin Terminal	132	6.2	8.4	6.2	8.4
MRT - Merredin Terminal	220	3.8	5.0	3.8	5.0
MW- Mundaring Weir	66	3.7	2.6	3.7	2.6
NOR - Northam	132	5.3	4.9	5.3	4.9

49 AC component of the initial symmetrical short circuit current which occurs directly after the initiation of the fault (RMS value).

NOR - Northam	66	4.7	4.4	4.7	4.4
PCY - Piccadilly St	132	4.7	5.8	4.7	5.8
PKS - Parkeston	132	4.7	5.6	4.7	5.6
SVY - Sawyers Valley 132 kV	132	7.8	6.9	7.8	6.9
SX - Southern Cross	66	0.6	0.4	0.6	0.4
WKT - West Kalgoorlie	132	4.7	6.1	4.7	6.1
WKT - West Kalgoorlie	220	2.6	3.3	2.6	3.3
WMK - Western Mining Kambalda	132	2.8	3.1	2.8	3.1
WMS - Western Mining Smelter	132	4.3	4.8	3.7	2.6
WUN - Wundowie	66	2.9	2.1	2.9	2.1
YER - Yerbillon	66	1.2	0.9	1.2	0.9
YLN - Yilgarn	220	2.6	2.6	2.6	2.6
East Perth and CBD Region					
CK - Cook Street	132	22.8	22.7	22.7	22.6
EP - East Perth	66	5.6	7.0	5.6	7.0
EP - East Perth	132	24.8	26.1	24.6	25.9
F - Forrest Ave	66	5.2	5.6	n/a	n/a
HAY - Hay Street	132	21.4	20.9	21.3	20.8
JTE - Joel Terrace 132 kV	132	24.4	25.0	24.1	24.6
MIL - Milligan Street	132	19.4	20.2	19.3	20.0
NP - North Perth	132	21.1	20.3	20.9	20.2
SUM - Summers Street	132	24.5	25.4	24.3	25.3
W - Wellington Street	66	5.4	6.0	5.4	6.0
Metro North Region					
A - Arkana	132	19.7	19.7	19.6	19.6
BCH - Beechboro	132	19.5	18.7	19.4	18.6
BCT - Balcatta	132	18.9	18.0	18.8	17.9
CTE - Cottesloe 132 kV	132	18.3	15.7	18.2	15.6
D-Darlington	132	13.6	12.8	13.5	12.7
FFD - Forrestfield	132	13.3	13.2	13.2	13.1
GLT - Guildford Terminal	132	22.9	25.0	22.7	24.8
H - Hadfields	132	16.5	15.5	16.4	15.4
HZM - Hazelmere	132	22.3	23.8	22.1	23.6
K - Kalamunda	132	11.3	10.8	11.3	10.8
MA - Manning Street	132	17.8	17.3	17.7	17.1
MCE - Medical Centre 132 kV	66	10.3	11.5	10.3	11.5
MDY - Munday	132	13.2	13.1	13.2	13.0
MJ - Midland Junction	132	21.5	23.2	21.3	23.0
MLA - Mount Lawley	132	21.2	21.7	21.1	21.4
MLG - Malaga	132	28.6	33.4	28.4	33.1
MO - Morley	132	17.3	18.3	17.2	18.2
N - Nedlands	66	11.0	11.3	11.0	11.3
NB - North Beach	132	19.3	19.2	19.2	19.1
OP - Osborne Park	132	19.5	19.8	19.4	19.5
SPK - Shenton Park	132	20.5	19.9	20.4	19.8
WD - Wembley Downs	66	9.6	8.1	9.6	8.0
WT - Western Terminal	66	21.7	21.9	21.6	21.8
Y - Yokine	132	19.4	19.3	19.3	18.6

Metro South Region					
AFM- Australian Fused Materials	132	20.1	18.7	20.1	18.7
AKW - ALCOA Kwinana	132	27.4	30.0	27.4	29.9
AMT - Amherst	132	19.8	17.0	19.7	16.9
APM - Australian Paper Mills	66	9.3	8.0	9.3	8.0
BEC - Beckenham	132	26.0	28.2	25.8	28.0
BEL - Belmont	132	18.6	18.1	18.5	18.1
BHK - Broken Hill Kwinana	66	6.3	7.3	6.3	7.3
BIB - Bibra Lake	132	21.5	18.5	21.4	18.5
BP - British Petroleum	66	6.5	7.3	6.5	7.3
BPR - B.P. Refinery	132	24.0	25.4	24.0	25.3
BTY - Bentley	132	19.2	16.9	19.1	16.8
BYF - Byford	132	13.2	11.6	13.2	11.6
CBP-CSBP	132	22.8	23.2	22.8	23.2
CC - Cockburn Cement	132	24.1	21.4	24.0	21.3
CCL - Cockburn Cement Ltd	132	24.0	21.3	23.9	21.2
CKB - Cockburn Power	132	30.9	33.7	30.8	33.5
CL - Clarence St	66	8.9	7.1	8.8	7.0
COL - Collier	66	9.0	7.2	8.9	7.0
CT - Cannington Terminal	66	14.5	17.5	14.5	17.5
CT - Cannington Terminal	132	27.7	30.0	27.5	29.8
CVE - Canning Vale	132	18.7	18.5	18.6	18.4
E - Edmund Street	66	10.9	10.5	10.8	10.5
G - Gosnells	132	22.1	21.4	22.0	21.3
GNI - Glen Iris	132	26.5	28.2	26.3	28.0
KDL - Kewdale	132	18.0	16.7	17.9	16.6
KDP - Kwinana Desalination Plant	132	24.9	27.0	24.8	24.8
KMK - Kerr McGee Kwinana	132	26.7	30.3	25.7	25.7
KND - Kwinana Donaldson Road	132	25.8	29.2	25.7	29.1
KNL - Kenwick Link	132	25.4	26.3	25.2	26.1
KNL - Kenwick Link	330	16.2	15.5	15.9	15.2
KPP - Kwinana Power Partnership	132	24.7	26.7	24.7	24.7
KW - Kwinana	66	6.7	8.2	6.7	8.2
KW - Kwinana	132	30.9	33.7	30.8	33.5
KW - Kwinana	330	20.2	20.7	19.8	20.3
LTH - Leath Road	132	21.2	21.2	21.2	21.2
MDN - Maddington	132	22.4	20.5	22.2	20.4
MED - Medina	132	22.8	20.4	22.7	22.7
MH - Mandurah	132	10.6	10.2	10.5	10.5
MSR - Mason Road	132	26.7	30.3	26.6	30.2
MSS - Meadow Springs	132	11.1	11.1	11.1	11.1
MUR - Murdoch	132	23.3	22.0	23.2	21.9
MYR - Myaree	66	8.7	7.4	8.7	7.4
OC – O'Connor	66	9.9	9.8	9.9	9.8
OFE - Office Road	132	22.2	21.9	22.1	21.9
PLD - Parklands	132	11.1	11.1	11.1	11.1
PNJ - Pinjarra	132	14.1	12.9	14.0	12.8
RO - Rockingham	132	19.8	18.8	19.8	18.8

RTN - Riverton	132	19.6	17.4	19.5	17.3
RVE - Rivervale	132	17.5	16.4	17.4	16.3
SF - South Fremantle	132	27.0	24.5	26.9	24.4
SF - South Fremantle	66	14.0	17.2	14.0	17.1
SNR - Southern River	132	20.3	18.8	20.2	18.7
ST - Southern Terminal	132	30.6	34.2	30.4	34.0
ST - Southern Terminal	330	21.4	22.2	20.9	21.7
TLA - Tianqi Lithium Australia	132	20.0	20.2	20.0	20.1
TPP- Tiwest Pigment Plant	132	26.7	30.3	26.6	30.2
TT - Tate Street	66	12.6	13.6	0.0	0.0
VP - Victoria Pak	66	12.0	12.5	11.4	11.5
WAI - Waikiki	132	15.2	13.7	15.2	13.7
WE - Welshpool	132	20.7	20.8	20.6	20.7
WLN - Willetton	132	19.4	19.0	19.3	18.9
WM - Western Mining	132	22.2	21.7	22.1	21.6
North Region					
CKN - Clarkson	132	15.3	13.5	15.2	13.5
CPN - Chapman	132	3.3	4.0	3.3	4.0
CTB - Cataby	132	6.6	6.4	6.6	6.4
EDG - Edgewater	132	19.3	19.0	19.2	19.0
EMD - Emu Downs	132	5.2	4.8	5.2	4.8
ENB - Eneabba	132	6.4	6.0	6.4	6.0
ENT - Eneabba Terminal	330	3.8	4.7	3.8	4.7
GGV - Golden Grove	132	1.3	1.6	1.3	1.6
GNN - Newgen Neerabup	330	13.3	13.4	13.2	13.3
GRS - Greenough River Solar Farm	132	6.2	7.0	6.2	7.0
GTN - Geraldton	132	3.6	4.4	3.6	4.4
HBK - Henley Brook	132	12.8	10.5	12.8	10.4
JDP - Joondalup	132	18.8	18.1	18.7	18.0
KMC- Kerr McGee Cataby	132	6.6	6.4	6.6	6.4
KMM - Kerr McGee Muchea	132	14.3	10.6	14.2	10.6
KRA - Karara Mine	330	2.2	3.1	2.2	3.1
LDE - Landsdale	132	17.8	17.4	17.7	17.3
MBA - Mumbida Wind Farm	132	4.7	4.9	4.7	4.9
MGA - Mungarra	132	6.2	7.0	6.2	7.0
MOR - Moora	132	2.8	1.8	2.8	1.8
MUC - Muchea	132	17.9	14.2	17.9	14.2
MUL - Mullaloo	132	19.3	19.0	19.2	19.0
NBT - Neerabup Terminal	132	21.5	21.6	21.4	21.5
NBT - Neerabup Terminal	330	13.7	13.8	13.6	13.7
NOW - Nowergup	132	15.3	13.5	15.2	13.5
NT - Northern Terminal	132	28.6	33.4	28.4	33.1
NT - Northern Terminal	330	17.8	18.1	17.5	17.8
PBY - Padbury	132	17.7	16.4	17.6	16.4
PJR - Pinjar Power Station	132	29.8	32.3	29.7	32.2
RAN - Rangeway	132	3.4	4.1	3.4	4.1
RGN - Regans	132	6.0	5.8	6.0	5.8
TS - Three Springs	132	7.9	8.2	7.9	8.2

TST - Three Springs Terminal	132	7.8	8.5	7.8	8.5
TST - Three Springs Terminal	330	3.4	4.5	3.4	4.5
WDW - Warradarge Wind Farm	330	3.6	4.5	3.6	4.5
WGA - Wangara	132	17.2	16.3	17.1	16.2
WNO - Wanneroo	132	20.3	19.9	20.2	19.8
WWF - Walkaway Wind Farm	132	4.6	5.1	4.6	5.1
YDT - Yandin Terminal	330	5.2	5.6	5.1	5.6
YDW - Yandin Wind Farm	330	4.7	5.1	4.7	5.1
YP - Yanchep	132	15.0	13.2	15.0	13.2
South Region					
ALB - Albany	132	1.6	1.9	1.6	1.9
APJ - ALCOA Pinjarra	330	14.9	14.9	14.8	14.9
APJ - ALCOA Pinjarra	132	14.8	14.9	14.8	14.9
BDP- Binningup Desalination Plant	132	11.5	9.3	11.6	9.3
BGM - Boddington Gold Mine	132	10.0	10.0	9.8	9.8
BLW - Bluewaters Terminal	330	21.4	20.4	19.4	18.2
BNP - Beenup	132	1.2	1.2	1.2	1.2
BOD - Boddington	132	10.0	10.0	9.8	9.8
BSI- Barrack Silicon Smelter	132	14.9	13.4	15.0	13.4
BSN - Busselton	66	4.2	5.2	4.2	5.2
BSN - Busselton	132	2.6	3.0	2.6	3.0
BTN - Bridgetown	132	4.5	4.7	4.4	4.7
BUH - Bunbury Harbour	132	9.6	9.5	9.5	9.5
BWP - Bluewaters Power Station	330	21.4	20.4	19.4	18.2
CAP - Capel	66	5.1	5.1	5.1	5.1
CLP - Coolup	66	1.0	0.7	n/a	n/a
CO - Collie	66	2.1	1.7	2.1	1.7
CPS - Collie Power Station Terminal	330	19.5	18.6	18.0	17.1
KAT - Katanning	66	1.5	1.7	1.5	1.7
KEM - Kemerton	132	21.0	22.2	20.7	22.1
KEM - Kemerton	330	21.0	19.4	19.9	18.4
KMP - Kemerton Power	330	20.0	18.3	19.0	17.5
KOJ - Kojonup	66	3.8	4.2	3.8	4.1
LWT - Landwehr Terminal	330	16.4	15.6	16.0	15.2
MBR - Mount Barker	132	1.6	1.7	1.6	1.7
MJP - Manjimup	132	3.0	3.1	3.0	3.1
MR - Margaret River	66	1.6	1.8	1.6	1.8
MRR - Marriott Road	132	16.8	16.4	17.0	16.4
MU - Muja	66	3.6	3.8	3.6	3.8
MU - Muja	132	17.7	19.9	17.1	19.0
MU - Muja	220	8.4	9.3	8.1	8.9
MU - Muja	330	21.5	20.7	18.4	16.1
NGN - Narrogin	66	1.2	1.6	1.2	1.6
NGS - Narrogin South	220	3.7	3.0	3.7	3.0
OLY - Oakley	330	17.0	14.8	16.5	14.5
PIC - Picton	66	9.5	12.0	9.6	12.0
PIC - Picton	132	11.3	11.5	11.3	11.7
SHO - Shotts	330	21.1	20.2	19.4	18.4

WAG - Wagin	66	1.2	1.0	1.2	1.0
WAPL- Worsley Alumina Pty Ltd	66	4.0	4.5	4.0	4.5
WAPL- Worsley Alumina Pty Ltd	132	14.5	16.7	14.4	16.6
WCG- Worsley Co Generation	132	14.6	16.7	14.5	16.6
WCL -Western Collieries Limited	132	13.6	11.9	13.4	11.7
WGP - Wagerup	132	8.6	6.9	8.5	6.9
WLT - Wells Terminal	132	11.4	12.3	11.2	12.1
WLT - Wells Terminal	330	7.1	6.7	6.9	6.5
WOR - Worsley	132	14.6	16.7	14.5	16.6
WSD - Westralian Sands	66	4.8	4.1	4.8	4.1

Table 46: Minimum fault levels

		Current Levels (0 years)		Future Levels (5 years)	
Substation	**Voltage (kV)**	**Fault level 3-phase (kA)**	**Fault level 1-phase (kA)**	**Fault level 3-phase (kA)**	**Fault level 1-phase (kA)**
East Region					
BDE - Bandee	66	1.4	1.2	1.4	1.2
BKF - Black Flag	132	1.2	1.4	2.0	1.8
BLD - Boulder	132	2.7	3.3	3.2	4.1
BNY - Bounty	132	0.6	0.4	0.6	0.4
CAR - Carrabin	66	1.0	0.8	1.0	0.8
CGT - Collgar Terminal	220	0.6	0.6	1.9	0.6
CGW - Collgar Wind Farm	220	1.9	2.2	1.9	2.2
CUN - Cunderdin	66	0.9	0.7	0.9	0.7
JAN-Jan	132	1.7	1.8	1.7	1.8
KDN - Kondinin	220	1.3	1.3	1.3	1.3
KDN - Kondinin	132	0.8	0.9	0.8	0.9
KEL - Kellerberrin	66	0.9	0.7	0.9	0.7
LEF-Lefroy	132	1.8	1.8	1.8	1.8
MDP - Merredin Power Station	132	3.0	4.0	2.9	4.0
MER - Merredin	66	1.9	2.5	1.9	2.5
MER - Merredin	132	2.7	3.4	2.7	3.3
MRS - Merredin Solar Farm	220	1.0	1.4	1.9	2.6
MRT - Merredin Terminal	132	2.3	3.2	2.3	3.2
MRT - Merredin Terminal	220	1.0	1.4	1.0	1.4
MW- Mundaring Weir	66	0.8	0.6	0.8	0.6
NOR - Northam	132	2.7	2.6	2.7	2.5
NOR - Northam	66	2.3	1.6	2.3	1.6
PCY - Piccadilly St	132	2.1	2.6	2.7	3.3
PKS - Parkeston	132	0.6	0.5	2.1	2.6
SVY - Sawyers Valley 132 kV	132	0.5	0.4	1.3	1.0
SX - Southern Cross	66	1.1	0.8	0.5	0.4
WKT - West Kalgoorlie	132	2.1	2.7	2.1	2.7
WKT - West Kalgoorlie	220	0.6	0.5	0.6	0.5
WMK - Western Mining Kambalda	132	0.6	0.7	1.5	1.4
WMS - Western Mining Smelter	132	0.6	0.7	0.6	0.7
WUN - Wundowie	66	0.9	0.7	1.1	0.8

YER - Yerbillon	66	0.7	0.6	0.9	0.7
YLN - Yilgarn	220	2.0	1.8	0.7	0.7
East Perth and CBD Region					
CK - Cook Street	132	11.1	10.5	10.0	9.7
EP - East Perth	66	4.7	5.9	4.6	5.7
EP - East Perth	132	11.9	13.1	10.9	12.0
F - Forrest Ave	66	4.4	4.8		
HAY - Hay Street	132	11.7	11.4	10.5	10.4
JTE - Joel Terrace 132 kV	132	13.8	14.8	12.2	13.3
MIL - Milligan Street	132	10.3	10.3	9.1	9.3
NP - North Perth	132	12.5	13.1	9.9	8.8
SUM - Summers Street	132	13.7	14.9	12.1	13.3
W - Wellington Street	66	4.5	5.1	4.4	5.0
Metro North Region					
A - Arkana	132	7.3	6.2	6.7	5.8
BCH - Beechboro	132	6.2	5.3	5.8	5.0
BCT - Balcatta	132	8.3	7.7	7.4	7.1
CTE - Cottesloe 132 kV	132	6.9	5.5	6.5	5.3
D-Darlington	132	4.9	4.7	4.7	4.5
FFD - Forrestfield	132	4.2	4.1	4.0	3.9
GLT - Guildford Terminal	132	1.4	0.8	1.4	0.8
H - Hadfields	132	7.5	6.5	6.8	6.1
HZM - Hazelmere	132	6.6	5.2	6.1	4.9
K - Kalamunda	132	5.1	3.9	4.8	3.8
MA - Manning Street	132	8.0	7.0	7.2	6.6
MCE - Medical Centre 132 kV	66	6.2	4.8	6.0	4.7
MDY - Munday	132	4.2	3.3	4.0	3.2
MJ - Midland Junction	132	3.8	3.4	10.5	11.2
MLA - Mount Lawley	132	12.0	13.7	10.4	12.0
MLG - Malaga	132	15.9	19.8	13.3	16.6
MO - Morley	132	6.7	5.3	6.2	5.0
N - Nedlands	66	6.8	6.3	6.6	6.2
NB - North Beach	132	9.6	9.1	8.5	8.3
OP - Osborne Park	132	10.0	9.6	8.9	8.7
SPK - Shenton Park	132	6.5	4.6	6.0	4.4
WD - Wembley Downs	66	3.8	2.5	3.7	2.5
WT - Western Terminal	66	3.3	2.1	7.6	2.0
Y - Yokine	132	8.0	7.1	7.3	6.6
Metro South Region					
AFM- Australian Fused Materials	132	11.6	11.8	10.6	11.0
AKW - ALCOA Kwinana	132	14.6	16.9	13.0	15.1
AMT - Amherst	132	6.1	5.0	5.7	4.7
APM - Australian Paper Mills	66	4.0	2.8	3.9	2.8
BEC - Beckenham	132	14.7	16.5	6.2	15.0
BEL - Belmont	132	8.1	6.7	13.3	6.5
BHK - Broken Hill Kwinana	66	5.3	6.1	5.1	6.0
BIB - Bibra Lake	132	7.3	6.5	6.9	6.3
BP - British Petroleum	66	3.9	3.9	3.9	3.9

BPR - B.P. Refinery	132	12.6	13.8	11.3	12.5
BTY - Bentley	132	7.9	6.8	7.4	6.7
BYF - Byford	132	5.1	3.4	4.9	3.4
CBP-CSBP	132	12.5	13.6	11.3	12.4
CC - Cockburn Cement	132	9.2	7.9	8.6	7.5
CCL - Cockburn Cement Ltd	132	13.0	13.2	11.9	12.2
CKB - Cockburn Power	132	14.1	16.1	12.8	14.7
CL - Clarence St	66	4.9	3.4	4.8	3.4
COL - Collier	66	4.8	3.4	4.6	3.2
CT - Cannington Terminal	66	0.6	0.5	0.6	0.5
CT - Cannington Terminal	132	2.3	1.5	2.3	1.5
CVE - Canning Vale	132	7.9	6.3	7.5	6.1
E - Edmund Street	66	6.8	5.8	6.6	5.7
G - Gosnells	132	10.2	9.6	9.6	9.1
GNI - Glen Iris	132	14.3	16.2	13.0	14.8
KDL - Kewdale	132	8.8	7.9	8.3	7.6
KDP - Kwinana Desalination Plant	132	13.9	15.9	12.5	14.4
KMK - Kerr McGee Kwinana	132	13.0	15.2	12.3	14.3
KND - Kwinana Donaldson Road	132	13.4	15.4	12.0	13.9
KNL - Kenwick Link	132	6.8	7.6	6.5	7.3
KNL - Kenwick Link	330	2.4	2.5	2.3	2.4
KPP - Kwinana Power Partnership	132	12.3	13.3	12.0	12.1
KW - Kwinana	66	2.6	2.6	2.6	2.6
KW - Kwinana	132	5.5	5.8	5.3	5.6
KW - Kwinana	330	4.4	3.7	4.2	3.6
LTH - Leath Road	132	11.8	12.6	2.6	11.8
MDN - Maddington	132	8.3	7.7	7.9	7.3
MED - Medina	132	5.6	4.3	10.7	4.2
MH - Mandurah	132	5.0	3.7	5.4	4.2
MSR - Mason Road	132	0.7	0.9	5.6	5.0
MSS - Meadow Springs	132	5.3	4.8	5.2	4.8
MUR - Murdoch	132	6.2	5.3	5.9	5.1
MYR - Myaree	66	4.4	3.0	4.3	3.0
OC – O'Connor	66	6.6	6.2	6.5	6.0
OFE - Office Road	132	12.2	13.0	11.1	11.9
PLD - Parklands	132	8.2	8.1	7.9	7.8
PNJ - Pinjarra	132	2.1	1.4	2.1	1.4
RO - Rockingham	132	7.9	7.0	5.2	6.8
RTN - Riverton	132	7.2	5.4	6.9	5.2
RVE - Rivervale	132	8.7	7.7	8.2	7.4
SF - South Fremantle	132	3.3	2.2	3.2	2.2
SF - South Fremantle	66	5.1	4.5	4.9	4.3
SNR - Southern River	132	8.8	7.3	8.4	7.0
ST - Southern Terminal	132	5.6	5.9	5.4	5.7
ST - Southern Terminal	330	4.0	3.8	3.6	3.4
TLA - Tianqi Lithium Australia	132	11.4	12.4	7.6	11.4
TPP- Tiwest Pigment Plant	132	13.8	16.3	12.3	14.6
TT - Tate Street	66	8.6	8.5		0.0

VP - Victoria Pak	66	7.8	7.4	7.6	7.2
WAI - Waikiki	132	3.1	2.3	10.4	2.3
WE - Welshpool	132	7.4	6.4	7.1	6.1
WLN - Willetton	132	7.1	6.9	6.8	6.7
WM - Western Mining	132	6.5	5.9	3.1	5.7
North Region					
CKN - Clarkson	132	5.3	4.5	4.6	4.1
CPN - Chapman	132	1.7	1.9	1.1	1.4
CTB - Cataby	132	3.4	3.5	2.6	2.9
EDG - Edgewater	132	11.5	12.3	9.8	10.7
EMD - Emu Downs	132	2.6	2.1	2.3	2.0
ENB - Eneabba	132	3.1	3.1	2.4	2.6
ENT - Eneabba Terminal	330	0.8	1.2	0.6	0.8
GGV - Golden Grove	132	1.1	0.8	1.0	0.8
GNN - Newgen Neerabup	330	5.8	6.0	4.9	5.3
GRS - Greenough River Solar Farm	132	2.7	3.1	1.7	2.1
GTN - Geraldton	132	1.4	1.9	1.0	1.4
HBK - Henley Brook	132	3.4	2.3	3.1	2.2
JDP - Joondalup	132	7.3	7.0	6.5	6.5
KMC- Kerr McGee Cataby	132	6.2	5.6	5.7	5.3
KMM - Kerr McGee Muchea	132	4.7	5.0	3.7	4.2
KRA - Karara Mine	330	8.8	7.6	7.3	6.7
LDE - Landsdale	132	1.6	1.6	1.4	1.4
MBA - Mumbida Wind Farm	132	1.2	1.6	1.7	1.8
MGA - Mungarra	132	1.9	2.5	0.9	1.3
MOR - Moora	132	1.0	0.7	0.9	0.7
MUC - Muchea	132	8.5	7.0	7.1	6.3
MUL - Mullaloo	132	8.8	8.6	8.0	8.0
NBT - Neerabup Terminal	132	9.3	9.0	7.6	7.8
NBT - Neerabup Terminal	330	0.6	0.9	0.5	0.7
NOW - Nowergup	132	9.5	9.3	8.0	8.2
NT - Northern Terminal	132	1.1	0.8	1.1	0.8
NT - Northern Terminal	330	5.0	5.2	4.3	4.6
PBY - Padbury	132	7.3	6.1	6.7	5.8
PJR - Pinjar Power Station	132	5.3	4.7	6.7	4.4
RAN - Rangeway	132	1.7	1.9	1.1	1.4
RGN - Regans	132	2.0	1.8	1.7	1.6
TS - Three Springs	132	2.8	2.8	1.8	2.0
TST - Three Springs Terminal	132	2.7	2.6	1.8	2.0
TST - Three Springs Terminal	330	1.6	2.0	1.5	1.9
WDW - Warradarge Wind Farm	330	2.3	2.6	2.0	2.2
WGA - Wangara	132	7.4	6.8	6.8	6.4
WNO - Wanneroo	132	8.6	8.5	7.6	7.7
WWF - Walkaway Wind Farm	132	0.9	1.0	0.9	1.0
YDT - Yandin Terminal	330	0.7	1.0	0.5	0.8
YDW - Yandin Wind Farm	330	3.0	3.1	2.6	2.8
YP - Yanchep	132	5.8	5.2	5.3	4.9
South Region					

ALB - Albany	132	0.7	0.7	0.7	0.7
APJ - ALCOA Pinjarra	330	4.1	3.3	5.9	5.5
APJ - ALCOA Pinjarra	132	4.2	3.4	6.5	6.0
BDP- Binningup Desalination Plant	132	8.2	7.0	8.1	6.9
BGM - Boddington Gold Mine	132	7.4	7.5	7.2	7.3
BLW - Bluewaters Terminal	330	5.0	5.0	4.8	4.4
BNP - Beenup	132	1.0	0.8	1.0	0.8
BOD - Boddington	132	6.8	6.5	6.6	6.3
BSI- Barrack Silicon Smelter	132	10.0	9.5	9.8	9.3
BSN - Busselton	66	1.3	1.0	1.6	1.5
BSN - Busselton	132	0.8	1.0	0.8	1.0
BTN - Bridgetown	132	2.6	1.9	2.6	1.9
BUH - Bunbury Harbour	132	2.2	1.5	2.2	1.5
BWP - Bluewaters Power Station	330	7.3	7.9	6.7	7.1
CAP - Capel	66	2.1	1.4	2.1	1.4
CLP - Coolup	66	0.8	0.6	n/a	n/a
CO - Collie	66	1.2	0.9	1.2	0.9
CPS - Collie Power Station Terminal	330	8.4	7.8	7.9	7.1
KAT - Katanning	66	0.5	0.3	0.5	0.3
KEM - Kemerton	132	2.4	1.8	9.7	10.4
KEM - Kemerton	330	4.0	3.2	5.9	5.8
KMP - Kemerton Power	330	8.0	7.6	7.4	7.0
KOJ - Kojonup	66	1.4	1.5	1.4	1.5
LWT - Landwehr Terminal	330	3.7	4.0	3.4	3.7
MBR - Mount Barker	132	0.6	0.7	0.6	0.7
MJP - Manjimup	132	1.6	1.3	1.6	1.3
MR - Margaret River	66	1.3	1.0	1.3	1.0
MRR - Marriott Road	132	9.4	9.0	9.3	8.7
MU - Muja	66	0.7	0.5	0.7	0.5
MU - Muja	132	0.9	0.8	0.9	0.8
MU - Muja	220	3.0	3.2	2.9	3.1
MU - Muja	330	4.3	4.1	4.1	3.8
NGN - Narrogin	66	1.1	1.4	1.1	1.4
NGS - Narrogin South	220	0.6	0.6	0.6	0.6
OLY - Oakley	330	0.9	1.1	0.9	1.1
PIC - Picton	66	1.5	1.1	1.5	1.1
PIC - Picton	132	2.0	2.2	2.0	2.2
SHO - Shotts	330	5.4	6.1	5.0	5.6
WAG - Wagin	66	0.6	0.5	0.6	0.5
WAPL- Worsley Alumina Pty Ltd	66	3.5	3.9	3.5	3.9
WAPL- Worsley Alumina Pty Ltd	132	7.7	8.7	7.6	8.5
WCG- Worsley Co Generation	132	9.5	11.1	9.4	10.9
WCL -Western Collieries Limited	132	3.5	2.9	3.5	2.8
WGP - Wagerup	132	2.9	2.0	2.8	2.0
WLT - Wells Terminal	132	6.6	7.0	6.4	6.7
WLT - Wells Terminal	330	4.3	3.5	4.2	3.4
WOR - Worsley	132	7.1	8.8	7.1	8.7
WSD - Westralian Sands	66	4.0	3.5	4.0	3.5

Appendix D: Transmission SSB Performance – System level

Western Power is obligate under its transmission licence to comply with the Access Code and meet the minimum service levels defined by the Service Standard Benchmarks (SSB's) that are approved under each Access Arrangement period.

Western Power plans the transmission network to meet these SSBs for the following service standard benchmarks, covering reliability and security of supply for users directly connected to the transmission network:

- Circuit Availability – the availability of the transmission network, measured by the actual number of hours the transmission network circuits are available, divided by the total possible hours available (after exclusions).
- LoSEF – the frequency (per year) of unplanned customer interruption events where the loss of supply:
  - exceeds 0.1 but less or equal to 1.0 System Minutes Interrupted (SMI)
  - exceeds 1.0 System Minutes Interrupted.
- Average Outage Duration – the total number of minutes duration of all unplanned interruptions on the transmission network divided by the number of unplanned interruption events (after exclusions).

Table 47: Transmission service standard performance

Service Standard	SSB	2019/20 actual	2020/21 actual	2021/22 actual	AA4 SSB met	Comments
Circuit Availability	≥97.8%	98.8%	98.5%	98.9%	✓	Performance exceeded the AA4 benchmark and remained stable over the period.
SMI LoSEF >0.1 and <= 1.0	≤ 26	15	14	5	✓	Performance exceeded the AA4 benchmark, with the 2021/22 period experiencing a significant improvement to past periods. The restoration of customers via the distribution system helped to maintain performance within benchmark.
SMI LoSEF >1.0	≤ 7	3	2	7	✓	Performance was within the AA4 benchmark but declined compared to the 2020/21 period. A number of reasons contributed to the decline in performance, including: • storm activity affecting a number of transmission lines • bushfire and pole top fires events on the Network
Average Outage Duration	≤ 1,234	751	976	590	✓	Performance exceeded the AA4 benchmark and was an improvement from previous periods.