Transmission System Plan - 2024

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Disclaimer

The information contained in the TSP 2024 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*.

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Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document.

Term	Definition	Term	Definition
AA	Access Arrangement	NOM	Network Opportunity Map
AEMO	Australian Energy Market Operator	NQRS	Network Quality and Reliability of Supply Code
APC	Annual Planning Cycle	NSP	Network Service Provider
BESS	Battery Energy Storage System	PASA	Projected Assessment of System Adequacy
BTM	Behind-the-meter	PoE	Probability of Exceedance
CBD	Central Business District	PTA	Public Transport Authority
DPV	Distributed Photovoltaic	pu	Per Unit
ELPS	Eastern Goldfields Load Permissive Scheme	PV	Photovoltaic
ELT2	Electricity Transmission Licence	ROI	Registration of Interest
EMT	Electro-magnetic Transient	SMI	System Minutes Interrupted
EPWA	Energy Policy WA	SSB	Service Standard Benchmarks
ERA	Economic Regulation Authority	SVC	Static VAR Compensator
ESOO	Electricity Statement of Opportunities	SWIS	South West Interconnected System
EV	Electric Vehicle	SWISDA	SWIS Demand Assessment
GIA	Generator Interim Access	TR	Technical Rules
kV	Kilovolt	TSP	Transmission System Plan
kW	Kilowatt	TXIP	Transmission Infrastructure Plan
MVA	Mega Volt Ampere	VAR	Volt Ampere Reactive
MVAr	Mega Volt Ampere Reactive	WEM	Wholesale Electricity Market
MW	Megawatt	WF	Wind Farm
MWh	Megawatt hours	WOSP	Whole of System Plan
NCESS	Non-Co-optimised Essential System Services		

1. Executive Summary

The Transmission System Plan (TSP) is updated annually to provide a 10-year investment plan for the transmission network[1]. TSP 2024 is the third edition, covering the FY2023/24 to FY2033/34 planning horizon to support alignment with Western Power's latest demand forecast and maintain continuity with existing network planning activities[2].

This version of the TSP is built on modelling assumptions introduced in TSP 2023, including coal fired generation retirements, the entry of battery energy storage solutions (BESS) and new renewable energy systems. Future TSPs are expected to provide greater insights into the performance of the transmission system and emerging constraints, solutions, and opportunities.

The commencement of security-constrained economic dispatch, driven by reforms to the WEM Rules, coincided with the publication of TSP 2023, and will provide 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 and prospective transmission customers.

The release of TSP 2024 follows the publication of key long-term planning documents, including the SWIS Demand Assessment (SWISDA[3]) released in May 2023 and the Transmission Infrastructure Plan (TXIP[4]) released in May 2024. These documents point to an ongoing evolution of the transmission system over the long term. Some of these findings and actions have been incorporated in to this plan, whereas other potential transmission builds are currently being planned and scoped and are not yet at the stage to include in this document. Future versions of the TSP will reflect the full suite of potential investments, as they are refined through the Whole of System Plan process.

1 Western Power is obligated under the Wholesale Electricity Market (WEM) Rules to finalise and publish the TSP before 1 October each year.
2 Current demand forecasts were produced in 2024, covering the period from 2023/24 to 2033/34.
3 SWIS Demand Assessment
4 SWIS Transmission Infrastructure Planning Update May 2024

Key findings of TSP 2024

1. Continuing 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 demand uncertainty are:

a. climate change impacts;

b. decarbonisation of industry;

c. developments in the energy industry such as hydrogen production;

d. distributed Photovoltaic (DPV) systems integration;

e. uptake of Behind-the-meter (BTM) batteries;

f. increased Electric Vehicle (EV) usage, and charging arrangements; and,

g. high variability in annual demand forecasts, present increasing challenges in planning for the transmission network and optimising timing triggers for new investment.

2. Transformation of energy generation. 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. The connection of renewable energy projects in viable regions is expected to drive transmission expansion into new locations in the SWIS. For example, the TXIP[4] projects are the first steps in reshaping the transmission network to accommodate future needs.

3. System peak demand. This is forecast to increase at an average annual rate of ~1% over the next decade, based on Western Power's 2023 Probability of Exceedance (PoE) 10 demand forecasts (covering the period 2023/24 to 2033/34)[5]. 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 and Byford area (Metro South Region) remain constrained during peak demand conditions. Western Power has several projects progressing to alleviate these constraints and provide flexibility to facilitate higher utilisation levels. On a substation basis, the increase in peak demand is expected to result in 23 substation capacity issues requiring addressing over the study period. Refer to section 8 for further details.

4. Continuing growth in DPV connections is expected to drive lower SWIS system minimum demands. Small-scale solar, or distributed photovoltaic (DPV), uptake is expected to continue increasing, with an estimated 6.5 gigawatts (GW) of capacity to be installed in the SWIS by 2033-34[6]. As a result of the expected increasing DPV capacity being connected on the SWIS over time, managing power system security and reliability during periods of low operational demand[7] is becoming increasingly challenging, particularly in relation to voltage management and system stability. Minimum demand periods continue to present high risks for planning and operating the transmission network over the short to medium-term[8].

[5] Excluding the step change in demand because of block loads.

[6] AEMO presentation to Synergy Board, e.g. see pps. 6, 9.

[7] 2024-wem-electricity-statement-of-opportunities.pdf (aemo.com.au), see pps. 3, 9, 65.

[8] See DPVM-Policy-Paper-261121-2.pdf (www.wa.gov.au).

2. The South West interconnected system

2.1 The Western Power Network (WPN)

The South West interconnected system (SWIS) is the interconnected transmission and distribution systems, generating works and associated works located in the South West of the Western Australia. The SWIS extends generally between Kalbarri, Albany, and Kalgoorlie, into which electricity is supplied by electricity generation plant[9]. The security, reliability, and operation of the SWIS and its networks are subject to various laws, regulations, codes, and rules.

Western Power builds, operates and maintains the transmission[10] and distribution networks within the SWIS. Western Power's networks cover the area from Kalbarri in the north to Albany in the south, and from Kalgoorlie in the east to the metropolitan coast. In all, the Western Power Network (WPN)[11] services an area of 255, 064 km^2 and supplies approximately 1.2 million connected customers[12].

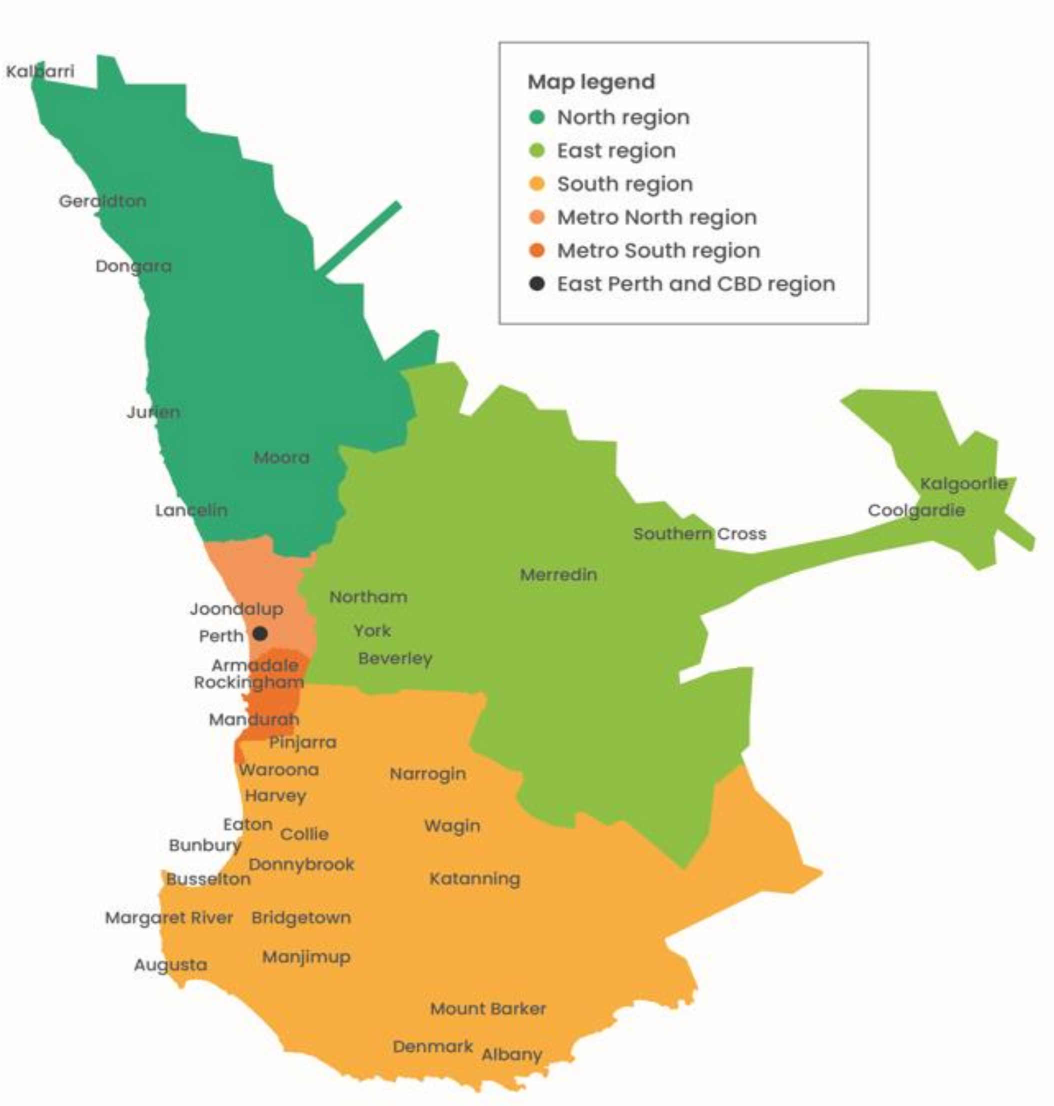

Figure 1: Western Power's network regions within the SWIS

[9] Electricity Industry Act 2004.pdf (legislation.wa.gov.au) s.3, p. 6.

[10] What is Transmission and why it matters (westernpower.com.au).

[11] The WPN is defined in the Access Code, enac-consolidated-version_priority-project-amendments.pdf (www.wa.gov.au), p. 43.

[12] What we do (westernpower.com.au).

3. Role of the Transmission System Plan

3.1 TSP requirements

Clause 4.5B of the WEM Rules requires Western Power to develop a TSP.

There is a range of content that the TSP addresses, and at a high level, these can be summarised as:

(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*[13].

Subsequent WEM Rules 4.5B clause provide the more detailed requirements. After the WEM Rules requirement to publish the TSP commenced, Western Power published TSPs in October 2022 and October 2023. Those initial TSPs were based on adapting established models and methods used to produce Western Power's previous annual planning reports prior to 2020 (for examples, see Western Power's website).

3.2 TSP Approach

The TSP 2024 is being published within the same timeframe as the constrained WEM in the SWIS is commencing. The implementation date for the major WEM reforms including Security Constrained Economic Dispatch (SCED) and associated Essential System Services (ESS) was on 1 October 2023. This start date aligned with the annual Reserve Capacity year start and marked a start of wider transitional arrangements affecting for the SWIS market, and the relevant connections and networks.

From that 2023 implementation date, new contexts for reporting and planning the SWIS transmission network have commenced. These circumstances imply a step change in data (and interpretation) for a range of critical planning sources. As such, this will impact planning and reporting being aligned to a range of requirements, such as:

- the WEM Rules requires the TSP, under clause 4.5B of the WEM Rules;
- the Access Code requires the NOM under clause 6.A of the Access Code;
- industry, and utility inputs to wider industry reports, (e.g. ESOO, WOSP, etc.); and,
- AA5 includes additional actions and increased reporting requirements.

As a result, planning, modelling, and operational datasets, and baselines are presently being established, collected, and refined – in line with the constrained WEM developments – and Western Power's approach for TSP 2024 is adaptive, and as such, is different to previous TSPs. Thus, the TSP 2024 includes some overlaps with other documents, as well as areas with no previous reporting. In some cases, this implies a change to the previous annual planning reports. In other cases, aspects of TSP reporting are being refined; so new processes and resources are being developed. New WEM and WPN contextual long term planning content and benchmarks are being established in suitable annual cycles.

13 TSP requirements can be found in the Wholesale Electricity Market Rules (WEM Rules), clause 4.5B.

Further, it is projected that critical data and modelling upgrades in the 2024/2025 FY will facilitate stepwise improvements for future TSP releases. For example, TSP data improvements are expected prior to the release of TSP2025, such as:

- emerging maturity of data being aggregated in the WEM constrained market (pre and post October 2023) and step wise understanding the range of impacts on SWIS transmission planning within this emerging environment (e.g. actual vs. expected);
- commencement of 'market' and 'network' modelling software presently being trialled and integrated with planning processes used by Western Power. This will improve TSP modelling of the SWIS (as WEM Network Operator) and the WPN (from TNSP perspective); and,
- incorporation of relevant TSP aspects arising from the anticipated development and release of 2024/2025 WOSP.

Western Power recognises the importance of working with AEMO and EPWA in developing the TSP to align planning inputs such as demand forecasts, generation dispatch scenarios/patterns, credible contingency events, and market costs and impacts. As such, the draft TSP 2024 has been circulated amongst key energy sector stakeholders to gain and consider their feedback.

3.3 Interaction between the TSP and other documents

The Western Power networks within the SWIS are unusual for two reasons:

a. geographical size and overall low density of connections; and
b. the 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.

Granularity of sub-division and the purpose for network "regions" given in other transmission planning documents vary. Western Power's approach has traditionally been to aggregate up to six main "regions", however, the WOSP refers to 11 regions, whilst the ESOO adds further subdivision into 14 smaller units.

3.3.1 Interaction between the TSP and WOSP

An initial version of the WOSP was developed and delivered in August 2020[14]. The WEM Rules currently require the next version to be published by 30 September 2025. The WOSP has a critical interaction with the TSP as it sets out a 20-year forward outlook for the power system, and it is developed in consultation with key industry stakeholders.

The inaugural WOSP developed a view of how the SWIS may evolve, across a 20-year outlook. 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. 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. Identification of network constraints, with major transmission inter-nodal constraints and augmentation are developed in the WOSP. The TSP will:

a. complement the WOSP analysis, while fine-tuning required augmentation technical details, costs, and binding constraint timelines

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

b. identify intra-nodal constraints and customer load/generation growth requiring network augmentation
c. optimise major network asset replacement works.

More sophisticated SWIS modelling is under development with the aim that future TSPs will develop import and export boundaries that will better align with the boundaries represented in the WOSP. This will ensure better consistency in outputs when planning for the transmission system.

3.3.2 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[15], published together annually with the TSP on an annual basis, on or before 1 October each year.

The primary purpose of the NOM is to present network opportunities on both the distribution and transmission system within a five-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 alternative options 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[16].

For further detail on network opportunities which are covered in the NOM, how they are developed and the process to submit an alternative option, refer to the NOM 2024[17].

3.4 Interaction with policy announcements

3.4.1 Coal-fired generation retirements

As announced by the State Government, the staged retirement of the Muja and Collie coal-fired power stations is planned to be complete by 2030.

To determine impacts on the transmission network of these retirements Western Power has worked 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 transmission system.

3.4.2 Major Transmission network developments

The SWIS Demand Assessment (SWISDA[3]) collated estimates of industry data to quantify a range of potential changes in electricity demand over the next 20 years. The SWISDA has outlined a vision of scenarios the future transmission system will be expected to deliver. In addition, growing numbers of industries are expected to seek to decarbonise through electrification. Accordingly, it has structured

[15] https://www.wa.gov.au/system/files/2019-08/ElecNetworksAccessCode.pdf.
[16] Where a service is procured in response to a network opportunity, the NCESS framework applies (e.g. see section 12.2.4).
[17] Transmission system plan & network opportunity map (westernpower.com.au).

findings based on forecast requirements of existing industrial users on the SWIS, and contemplated potential growth in new technologies, and critical mineral related industries.

SWISDA identified potential network augmentations options between 2023 and 2042 in a series of stages, setting the groundwork for planning transmission infrastructure reinforcements.

Since this time, further refinement of the long-term plan has occurred, and an updated Transmission Infrastructure Plan was released in May 2024[18]. This plan envisaged a series of investments known collectively as the Clean Energy Link Program.

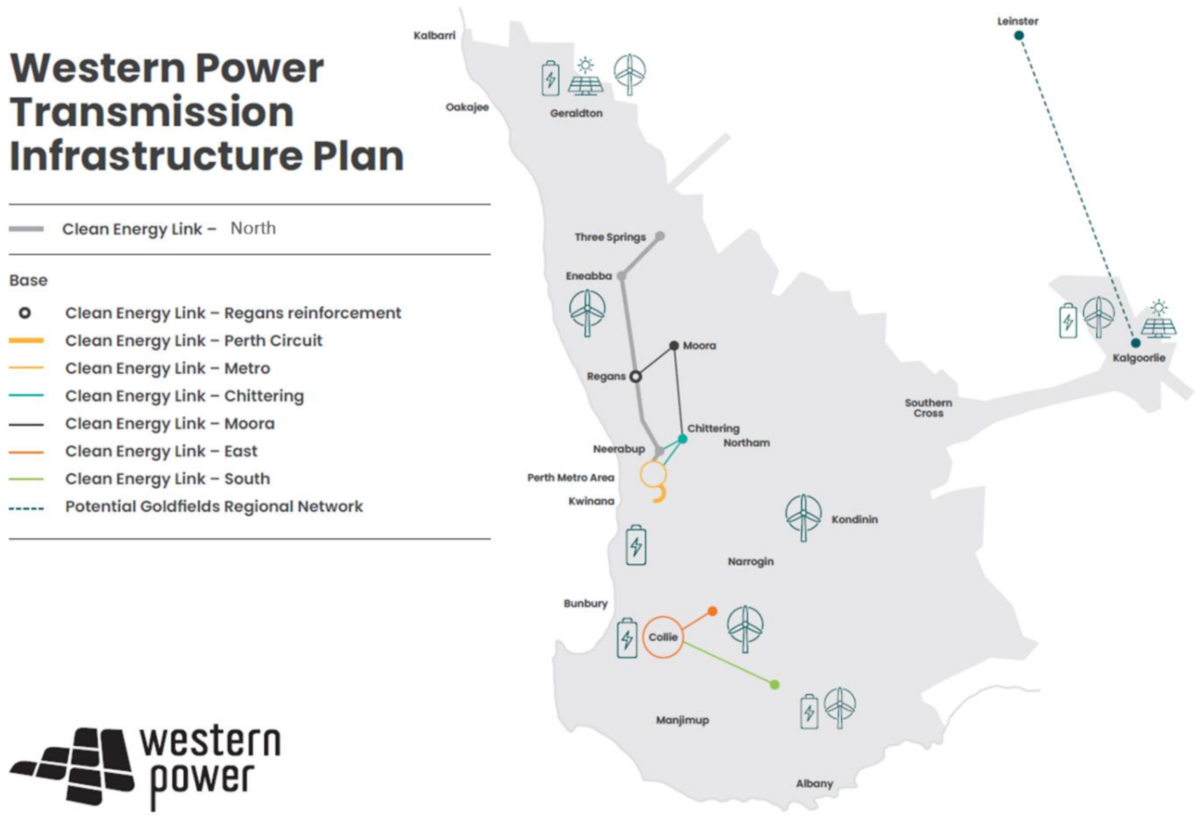

Figure 2: SWIS Transmission Infrastructure Plan (TXIP) map[4]

The first stage of works in the TXIP transmission augmentation has commenced, with planning and scoping underway to increase the capacity of the network's northern section. This vital network strengthening, known as Clean Energy Link – North has been allocated $655 million in funding by the State Government to commence.

Further funding of $503 million has been provided to assess and scope potential Clean Energy Link transmission projects in other parts of the SWIS in line with the SWIS Transmission Planning Update. This includes planning for new lines, reinforcements, and upgrades around key industry areas, including Kwinana and Collie, as well as upgrades between Geraldton and Perth to support development at Oakajee.

[18] https://www.wa.gov.au/system/files/2024-05/swis-transmission-planning-update.pdf

4. Modelling Assumptions

4.1 Key input data and assumptions

The reader is referred to the TSP 2023 for details and descriptions in the areas where they are applicable. Those 2023 approaches, studies, data, and details have formed the basis for TSP 2024, which has been developed in parallel with the commencement of WEM constrained market. As such, the content of TSP 2024 is somewhat transitory, and in some cases, looking at variations between the 2023 and 2024 TSPs might be helpful. Also, for information on how the planning cycle works please refer to TSP 2023, section 4.1.

Key input data and assumptions taken into consideration when developing the TSPs include[19]:

- WEM Technical Standards, as specified under WEM Rules clause 2.8.14.
- Power system security and reliability standards and requirements – clause 3 under the WEM Rules and clause 2 under the Technical Rules.
- Priority Project(s) 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.
- Government policy announcements that the Coordinator of Energy determines 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 clause 4.5A. For example, as is discussed in section 3.4, the retirement of the Muja and Collie coal-fired power stations is expected by 2030 in line with the position set out in the SWIS Demand Assessment.

4.2 Modelling parameters

The study period is defined as the period 2022/23 to 2032/33 (with revised boundary studies for inclusion in TSP 2024 updates, i.e. out to 2034). The reader is referred to the TSP 2023 for full modelling base details, with a summary of the approach listed below:

- DigSILENT Powerfactory used to perform system simulation studies.
- 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.
- Generation dispatch profiles for peak and minimum demand conditions are developed using a security constrained and economic dispatch based on merit order as implemented by AEMO.
- 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.

[19] As required under WEM Rules clause 4.5B.5, p. 407.

4.3 Annual planning cycle

The Annual Planning Cycle (APC) includes all the activities required to produce or update the network plans. This includes network-related expenditure proposed up to a 10-year period to meet a range of objectives and regulatory obligations, while maintaining an acceptable level of risk and performance for meeting regulators, organisational, and network users' needs; as well as meeting Western Power planning objectives.

4.4 Network planning process

Network planning involves considering the relevant corporate objectives, network strategies and corporate objectives; and follows a process to produce an optimised plan which prioritises and meets known constraints. The network planning process follows a general, five step process, as described below.

4.4.1 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[20], WEM Rules[21], Network Quality and Reliability of Supply Code (NQRS), and the Access Code – as well as its wider asset management requirements and objectives.

4.4.2 Step 2 – Solutions

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.

4.4.3 Step 3 – Optimisation

The optimisation process includes actions such as: identification of network need and opportunities; outputs from condition assessments; verification of the lowest-cost option; completion of risk reduction benefit assessments and, incorporation of the corporate strategy and plans for the network, including where higher capacity assets are needed in the long term, historical asset utilisation rates, and decommissioning of assets.

4.4.4 Step 4 – Prioritisation

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[22].

4.4.5 Step 5 – Forecasting 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 Technical Rules (westernpower.som.au).

21 Wholesale Electricity Market Rules.

22 'Criticality,' with respect to the transmission network, considers transformers, switchboards, and lines – as they can take longer to replace, or restored back into service, potentially impacting supply to large numbers of customers.

5. Energy and Demand Forecasts

5.1 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.

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 BIS Oxford which are analysed for impact and included where and if relevant.

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

- PoE10 where there is a 10% probability of demand exceeding the PoE10 value.
- PoE50 where there is a 50% probability of demand exceeding the PoE50 value.
- PoE90 where there is a 90% probability of demand exceeding the PoE90 value.

5.2 Customer Connections, 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 DPVs, and energy imports from 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.
- **DPV Capacity Forecast** - reliable long-term DPV installation forecasting is important for developing accurate forecasts for electricity consumption and demand. Although the mass adoption of 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 DPV. The model produces monthly forecasts at hierarchy levels comprising tariff type, customer segment and substation levels. It also reconciles forecasts at different hierarchy levels.

5.3 Difference between energy scenarios and demand forecasts

The TSP uses demand forecasts rather than energy scenarios to present the most likely network development pathway.

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. On the other hand, energy scenarios, (unlike demand forecasts), look at historical data and certain assumptions of the future. For example, to simulate scenarios, climate change or high electric vehicle uptake.

5.4 Difference between Western Power 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 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.

Western Power consults with AEMO on assumptions and inputs to maintain alignment, and to understand differences in demand forecasts.

5.4.1 ESOO 2024 forecast data released in June 2024

There are some differences between AEMO's recently published WEM ESOO 2024 and TSP 2024. Western Power's forecast is aimed at network build and considers non-network solutions. As a result, network related forecasts will translate into plans for program and project level investments. Thus, a higher level of certainty, and practicability applies, to ensure prudency and efficiency of spend.

Western Power will continue to monitor the key factors driving the change in the industry and endeavour to include them where applicable in future demand forecasting analysis.

It is noted that Western Power's forecasts are designed to understand load patterns and associated investments at lower levels of the network hierarchy, whereas the ESOO's goal is to encourage new market participation in generation on a system level.

5.5 Demand Forecasts

Western Power's forecasting reflects the challenges and opportunities the industry is facing, driven 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 PoE10 peak demand and system PoE50 system minimum demand forecasts used to model peak and minimum demand scenarios.
- Substation capacity assessments – non-coincidental system PoE10 peak demand forecasts.

5.6 Forecast Performance

5.6.1 Maximum Demand

Annual maximum demand on the network has been relatively variable since 2010, peaking above 3800 MW in all years except one, though the differences between the 2023 and 2024 summer maximum forecast chart demonstrates the potential increased volatility in annual peaks (represented by the forecast band).

Figure 3 demonstrates that at a system level, the forecast from 2023 captured the peak events from summer 2024 within the bounds of the PoE10 and PoE90 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 higher accounting for the greater volatility in annual peaks.

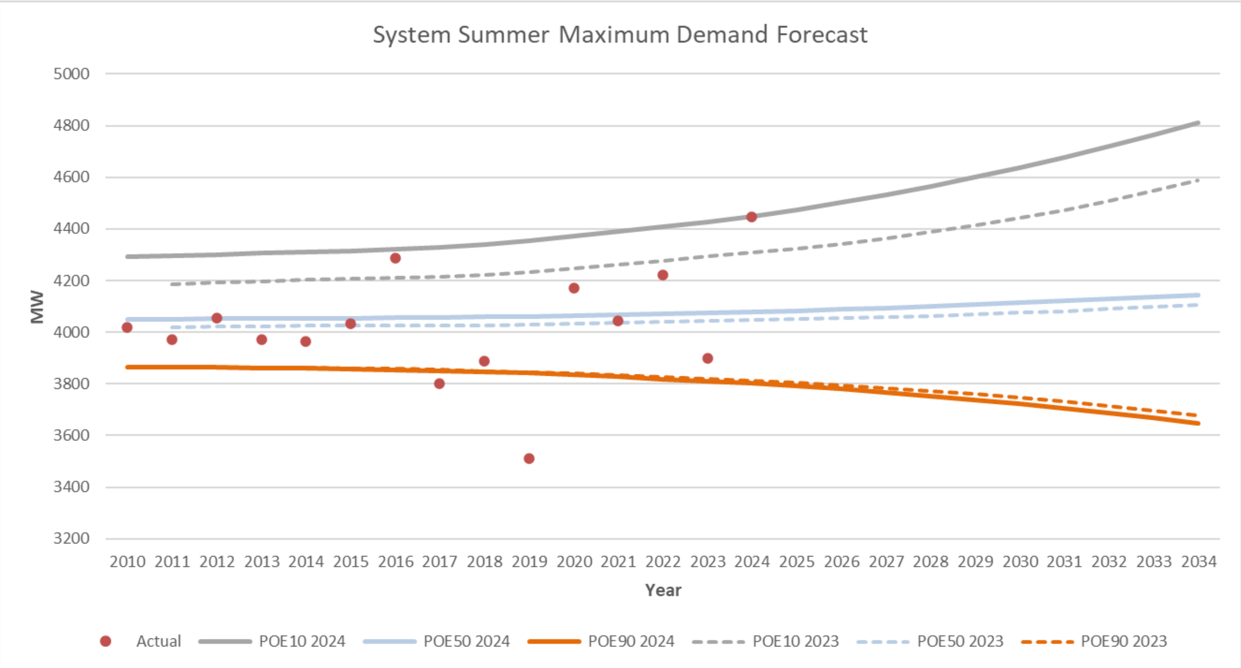

Figure 3: Historical and forecast system maximum demand – 2023 and 2024

The 2024 summer maximum demand of 4,448 MW occurred on 18 February 2024. Maximum demand was 536 MW (4448 – 3912 MW) i.e. almost 14 per cent higher than in 2023. It is likely that this was driven primarily by the hot summer's day, with associated elevated air-conditioning usage.

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.

5.6.2 Minimum Demand

Annual minimum demand on the network has consistently decreased and is forecast to continue decreasing. Increasing residential 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 2023 and 2024 Daily Minimum Demand Forecast chart shows the decreasing minimum demand.

Minimum demand on the network is creating increasing challenges in 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 595 MW was set in 2023, occurring on September 25, 2023[23]. It must be noted that the view provided in Figure 4 is indicative, it shows “system cumulative effect” of decreasing demand, it excludes network practical and security parameters (thus, 0 MW may not be the likely ‘actual’ system value).

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

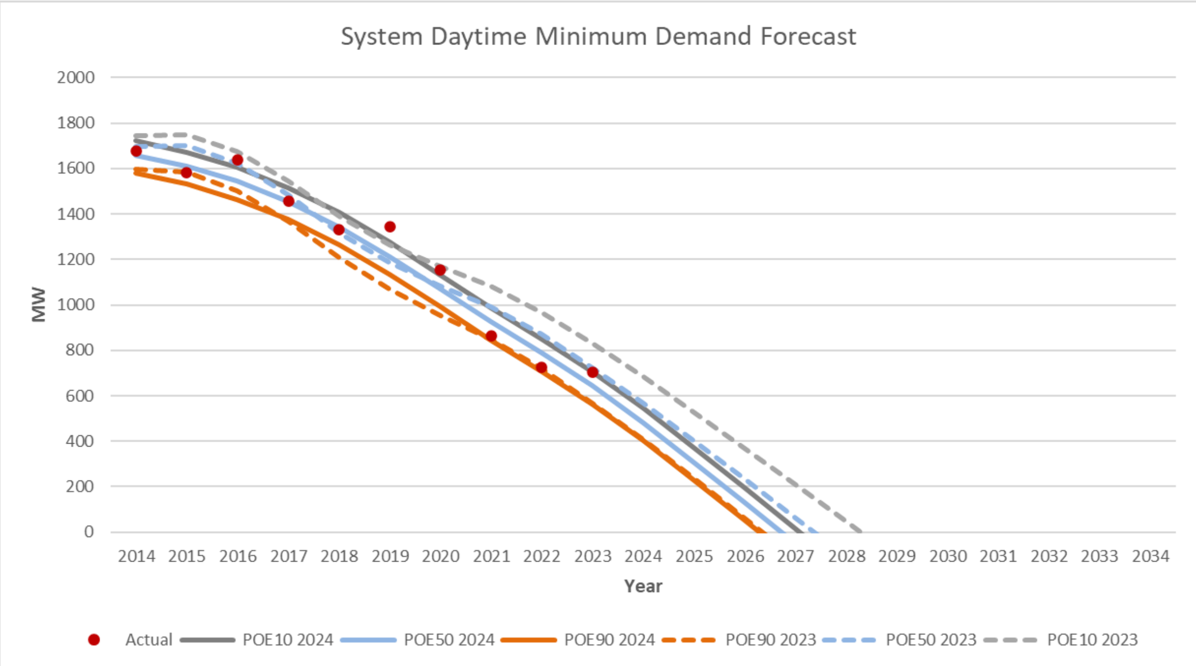

Figure 4: Historical and forecast system minimum demand - 2014 and 2034

[23] See 2024-wem-electricity-statement-of-opportunities.pdf, p. 43.

6. Generation Assumptions

Western Power's transmission planning responds to forecast growth in maximum demand and the expected connection of new generation[24]. Although Western Power's planning process considers a broader range of demand and generation scenarios, TSP 2024 presents development plans for the most 'efficient and likely' peak and minimum scenarios. Western Power consults with key stakeholders to develop these scenarios as a security constrained and economic dispatch based on merit order that would produce the lowest cost to the system.

6.1 Constrained Network Access

From 1 October 2023, the WEM has commenced constrained access operation[25] under the principles of Security Constrained Economic Dispatch (SCED)[26]. Under the reformed market, generation which relieves binding network constraints will be paid energy uplift payments. Network constraints may impact dispatch outcomes by limiting the flow of lower cost energy from constrained regions of the SWIS.

The cost of these uplift payments and other relevant information such as the location, magnitude and frequency of binding network constraints will now become available from October 2023. These data will be considered in future TSPs in determining the point at which network augmentation becomes more economically efficient when compared with dispatching generators participating in the market.

[24] New generation entrants are considered in system studies for the TSP when they have become committed and been signed a 'Network Access Application Offer'

[25] AEMO | WEM Procedures

[26] AEMO | Constraint Management

7. Compliance matters

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 reader is referred to the Transmission System Functional Requirements[27], which contains further comments on the WPN regulatory framework and technical compliance.

In summary, SWIS technical compliance can be linked to Western Power's WEM Rules obligations as Network Operator, and networks compliance links to Western Power's role as Network Service Provider in the Technical Rules.

7.1 Wholesale Electricity Market Rules

As already noted, there have been a series of evolutionary changes made to the WEM, and these have been accompanied by matching changes to the WEM Rules. For example, some technical content of the Technical Rules linked to the WEM achieving its objectives, have transferred into the WEM Rules. (e.g. "Appendix 12: Transmission Connected Generating System Generator Performance Standards. This Appendix lists each of the Technical Requirements for Transmission Connected Generating Systems and sets out the Ideal Generator Performance Standard, Minimum Generator Performance Standard, and any applicable Common Requirements for each Technical Requirement".

In addition, Western Power has WEM Rules obligations to meet as a SWIS Network Operator.

7.2 Technical Rules

The Technical Rules[28] 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, as well as the wider range of applicable obligations, while maintaining an acceptable level of risk and performance for customers in line with the broader network development plan.

7.3 Future regulation and rules improvements

It is expected that further evolution may continue as the WEM and the WPN adapt to the future needs of stakeholders (e.g. Regulators, System/Market/Network Operators, Service Providers, Users, participants, and operating facilities) within the SWIS. As such, there is expected change possible for both sets of Rules as these continue to be optimised and updated; and this can impact future TSP approaches, as the external planning inputs to the TSP continue to mature.

[27] Transmission Network Functional Requirements (westernpower.com.au), see section 2, p. 8,
[28] Technical Rules (westernpower.som.au)

8. SWIS Zone Substation – Capacity Assessment

Western Power's demand growth drivers such as population growth and EV uptake are expected to increase the utilisation of the network, particularly in the zone substations. Since the TSP 2023, the Western Power network has experienced a record heatwave. In 2023/24, Western Australia experienced an exceptionally intense summer, the second warmest on record characterised by elevated temperatures and high humidity, with 27 days registering temperatures above 35^0 C and nine days of maximum temperatures at, or above 40^0C.

8.1 Peak demand days

The first peak demand record since 2016[29], was set on 23 November 2023, prior to the onset of summer. This record was subsequently broken on multiple days across the summer of 23/24, which saw seven of the top 10 highest demand days on record, including the current all-time maximum operational demand record of 4233 MW, which was set on 18 February 2024. As shown in Figure 5, the top six operational demand peaks recorded in the state's main grid occurred between 31 January 2024 and 19 February 2024.

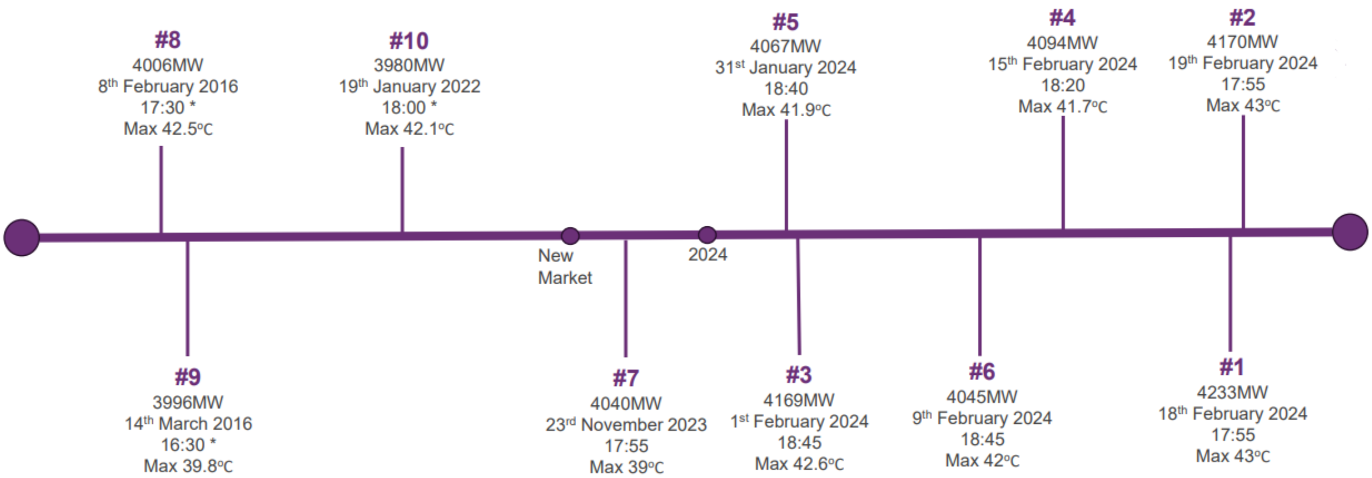

Figure 5: Top 10 highest demand days since the commencement of the WEM[30]

Updated forecasts from Western Power, AEMO and other agencies have rapidly changed from a relatively flat energy demand forecast to profiles that reflect sharp increase in electrification and the anticipated increase in severity and duration of heatwave events. In addition, the below factors are expected to contribute to the increased load in the network:

- increased Electric Vehicle (EV) take-up;
- a transition from gas towards the electrification of household appliances; combined with higher dependence on communications and electronics across the spectrum; and,
- plans to develop land and provide increased volumes of housing will likely require investment into additional zone substations, varying by their location, and result in a higher average demand for new housing developments.

[29] The peak operational demand record of 4006 MW was set on 8 February 2016

[30] Adapted from Real-Time Market Insights Forum 20 February 2024 (aemo.com.au), see p. 9.

8.2 Average substation utilisation

Customer expectations of reliability and their reliance of electricity is higher than it has ever been and will continue increasing in the context of electrification. This has the potential to change customer tolerance towards outages in the future and Western Power's approach to network planning. It is noted that this electrification will take place gradually over time, but there is a clear trend that newer residential dwellings have higher energy demand from the network than existing dwellings. Table 1 shows the weighted average substation utilisation for the WPN regions (noting that the legend for Utilisation colour coding as shown in Table 2 applies for both Table 1, and Table 4).

Table 1 Average substation utilisation for multiple regions.

Region	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
North	62.64%	62.36%	62.37%	62.99%	63.58%	64.04%	64.40%	64.80%	65.56%	66.43%
Metro North	82.31%	80.94%	81.73%	83.02%	84.30%	85.52%	86.66%	87.77%	89.49%	91.23%
East	70.31%	72.64%	69.91%	62.23%	62.41%	62.59%	63.77%	63.96%	64.33%	64.70%
East Perth & CBD	67.34%	60.29%	60.22%	59.94%	59.82%	60.11%	60.66%	61.13%	61.44%	61.42%
Metro South	86.50%	85.24%	86.29%	87.83%	89.37%	90.75%	91.97%	93.16%	95.08%	97.11%
South	73.54%	68.96%	69.85%	70.65%	71.43%	72.15%	72.87%	73.66%	75.01%	76.41%

Table 2 Utilisation legend (for Table 1 and Table 4)

LEGEND	Utilisation %
	Below 95%
	Between 95% - 98%
	Between 98% - 100%
	Between 100% - 110%
	Between 110% - 120%
	Above 120%

Electric vehicle growth

The expected addition of EV as a percentage of the total demand shows the significance of EV uptake growth. Table 3 shows the weighted average EV demand percentage for the WPN regions.

Table 3 Average EV demand percentage for multiple regions.

Region	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
North	1.64%	1.57%	1.50%	2.18%	2.85%	3.52%	4.17%	4.82%	5.87%	6.87%
Metro North	2.54%	3.35%	4.15%	5.41%	6.64%	7.83%	8.99%	10.13%	11.84%	13.48%
East	0.80%	0.72%	0.67%	1.05%	1.44%	1.83%	2.18%	2.56%	3.20%	3.84%
East Perth & CBD	1.09%	1.44%	1.81%	2.33%	2.85%	3.35%	3.82%	4.30%	5.15%	6.03%
Metro South	2.79%	3.68%	4.54%	5.75%	6.91%	8.05%	9.17%	10.27%	11.92%	13.49%
South	1.48%	1.97%	2.45%	3.44%	4.42%	5.38%	6.32%	7.23%	8.66%	10.03%
Total	2.26%	2.94%	3.61%	4.70%	5.75%	6.79%	7.79%	8.78%	10.30%	11.76%

Table 4 shows forecast peak load utilisation across the period 2024/25 to 2033/34 for highly loaded zone substations operated by Western Power. 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, additional transformer installations and establishment of new zone substations. Non-network options, such as demand-side management solutions are also considered.

As utilisation levels increase towards 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. For further details regarding other zone substations in the WPN network and their respective utilisation refer to the Network data 2024 spreadsheet[31].

[31] Transmission system plan & network opportunity map (westernpower.com.au)

Table 4 Forecast peak load utilisation across the period 2024/25 to 2033/34 for highly loaded zone substations operated by Western Power.

Region	Substation	EXISTING CAPACITY [MVA]	Forecast Utilisation (%) POE10 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Comments
North	Moora	16.35	110.45%	111.09%	111.75%	112.65%	113.54%	114.44%	115.36%	116.29%	117.62%	118.95%	Mitigation planning in progress.
	Three Springs	13.95	85.60%	85.17%	84.96%	85.02%	85.12%	85.21%	85.26%	85.26%	85.41%	85.53%	
Metro North	Arkana	72.16	83.07%	83.95%	84.81%	86.51%	88.22%	89.95%	91.69%	93.44%	96.06%	98.68%	
	Beechboro	86.28	90.59%	91.80%	93.02%	94.95%	96.92%	98.90%	100.89%	102.83%	105.40%	107.90%	
	Clarkson	55.70	132.47%	92.55%	94.03%	96.60%	99.11%	101.24%	103.07%	104.94%	107.93%	111.26%	Additional transformer (Execution, estimated in service by FY2026), which improves the substation capacity.
	Cottesloe	54.19	87.23%	87.95%	88.79%	89.88%	90.91%	91.86%	92.75%	93.66%	95.34%	97.08%	
	Hazelmere	27.15	101.27%	101.55%	101.98%	102.89%	103.77%	104.58%	105.38%	106.23%	107.60%	108.99%	Mitigation planning in progress.
	Henley Brook	52.61	101.06%	70.87%	73.03%	75.95%	78.90%	81.59%	83.98%	86.27%	89.18%	92.26%	Load transfer to Malaga by FY2025. Additional transformer (Execution, estimated in service by FY2026), which improves the substation capacity.
	Joondalup	52.67	99.04%	99.59%	100.21%	101.55%	102.89%	104.20%	105.50%	106.83%	108.82%	110.82%	Additional transformer (Scoping, estimated in service by FY2028).
	Landsdale	88.31	97.66%	98.53%	99.81%	101.92%	103.96%	105.72%	107.25%	108.78%	111.50%	114.42%	Additional transformer at WGA and load transfer (Scoping, estimated in service by FY2028).
	Manning Street	42.87	88.51%	89.35%	90.60%	92.70%	94.70%	96.39%	97.83%	99.30%	101.93%	104.82%	
	Mullaloo	65.73	86.21%	86.78%	87.77%	89.48%	91.35%	93.18%	94.83%	96.22%	98.12%	99.88%	
	North Beach	75.19	86.63%	87.02%	87.80%	89.45%	91.15%	92.63%	93.89%	95.11%	97.26%	99.59%	
	Padbury	81.79	92.00%	92.07%	92.63%	94.38%	96.12%	97.37%	98.16%	98.93%	100.95%	103.43%	
	Shenton Park	65.85	90.34%	91.43%	93.00%	94.53%	95.60%	96.46%	97.40%	98.47%	100.19%	101.81%	
	Wangara	27.75	96.66%	98.33%	99.60%	100.88%	102.31%	103.85%	105.42%	106.93%	108.82%	110.70%	Additional transformer (Scoping, estimated in service by FY2028).
	Wembley Downs	43.18	100.05%	101.18%	101.97%	102.79%	103.60%	104.70%	106.05%	107.41%	109.22%	110.76%	Mitigation planning in progress.
	Wanneroo	84.08	95.26%	97.64%	98.83%	99.45%	100.06%	101.42%	103.46%	105.47%	107.50%	108.80%	Additional transformer at JDP and load transfer (Scoping, estimated in service by FY2028).
	Yanchep	60.70	96.98%	99.24%	101.25%	103.68%	106.23%	108.95%	111.71%	114.33%	117.28%	120.04%	Additional transformer (Scoping, estimated in service by FY2027).
East	Black Flag	27.55	143.63%	142.84%	141.96%	64.31%	64.24%	64.38%	64.57%	64.63%	64.49%	64.26%	Additional transformer (Planning, estimated in service by FY2028).
	West Kalgoorlie 33kV	30.41	94.83%	116.14%	114.91%	62.38%	62.40%	62.42%	70.93%	70.95%	70.99%	71.02%	Additional transformer (Planning, estimated in service by FY2028).
CBD & East Perth	Joel Terrace	74.80	84.49%	86.81%	86.95%	87.13%	88.30%	90.65%	93.47%	95.88%	98.11%	99.64%	
Metro South	Amherst	84.56	88.52%	91.06%	93.33%	95.32%	96.78%	98.11%	99.61%	101.27%	103.58%	105.80%	
	Bibra Lake	55.76	114.76%	116.66%	118.61%	120.82%	122.87%	124.69%	126.36%	128.08%	131.00%	134.12%	Additional transformer (Scoping, estimated in service by FY2027).
	Byford	76.96	125.50%	108.27%	111.17%	114.59%	117.82%	120.72%	123.30%	125.76%	129.17%	132.70%	Additional trasnformer at WLN and cascaded load transfer (Execution Phase, estimated in service by FY2026). Potential New Zone Substation (Scoping Phase, estimated in service by FY2029).
	Gosnells	77.25	91.77%	93.43%	94.77%	96.54%	98.31%	100.36%	102.69%	104.97%	107.86%	110.42%	
	Maddington	25.98	116.46%	116.95%	118.27%	120.96%	123.63%	125.64%	127.06%	128.51%	131.58%	135.30%	Additional transformer (Scoping, estimated in service by FY2027).
	Mandurah	76.02	93.89%	96.12%	98.05%	100.02%	102.04%	104.29%	106.71%	109.10%	112.19%	115.08%	Load Transfer to Pinjarra by FY2025. Load Transfer to future Baldivis zone substation (Scoping, estimated in service by FY2028).
	Meadow Springs	86.31	96.33%	97.06%	98.99%	102.24%	105.40%	107.69%	109.23%	110.79%	113.83%	117.61%	Load Transfer to future Baldivis Zone substation (Scoping, estimated in service by FY2028).
	Medina	80.74	78.01%	79.77%	81.84%	84.73%	87.71%	90.58%	93.28%	95.86%	99.03%	102.23%	
	Pinjarra	52.51	83.71%	84.86%	86.22%	88.06%	89.90%	91.53%	92.96%	94.40%	96.57%	98.94%	
	Riverton	81.02	92.89%	93.86%	94.86%	96.39%	97.92%	99.45%	100.97%	102.50%	104.92%	107.37%	
	Rockingham	75.16	87.11%	86.62%	86.47%	88.00%	89.86%	91.24%	91.91%	92.34%	93.81%	95.81%	
	Southern River	85.16	118.21%	87.45%	88.10%	90.22%	92.94%	95.36%	97.06%	98.42%	100.88%	103.77%	Load transfer to WLN once the new transformer is installed. Additional transformer (Execution Phase, estimated in service by FY2026).
	Waikiki	80.48	103.49%	104.00%	105.24%	107.84%	110.15%	111.73%	112.75%	113.86%	116.33%	119.41%	Load Transfer to future Baldivis Zone substation (Scoping, estimated in service by FY2028).
	Willetton	26.29	111.29%	98.59%	99.97%	101.74%	103.46%	104.89%	106.04%	107.14%	108.86%	110.78%	Additional transformer (Execution Phase, estimated in service by FY2026).
South	Albany	59.90	99.95%	99.80%	101.44%	104.73%	107.23%	108.39%	109.18%	111.12%	115.73%	121.36%	Proposed replacement of old transformers progressively with higher capacity
	Bunbury Harbour	62.34	115.52%	117.17%	118.61%	120.55%	122.43%	124.49%	126.79%	129.12%	132.20%	135.09%	Load transfer to PIC and potential non network solutions being explored (Scoping, estimated in service by FY2027).
	Busselton	65.92	123.40%	74.72%	75.28%	76.41%	77.54%	78.68%	79.84%	81.01%	82.70%	84.38%	Additional transformer (Execution Phase, estimated in service by FY2026)
	Wagin	6.06	93.71%	93.71%	93.48%	93.59%	93.74%	94.06%	94.60%	95.31%	96.74%	98.19%	

9. Key Network Regions

Western Power's network is treated as six geographic regions for the purposes of network planning. Dividing networks into regions is useful in network planning, as each region has unique load characteristics and experiences similar network issues. Figure 6 illustrates the geographic boundaries between regions, with three regions covering the metro and three regions covering the remaining regional parts of the SWIS.

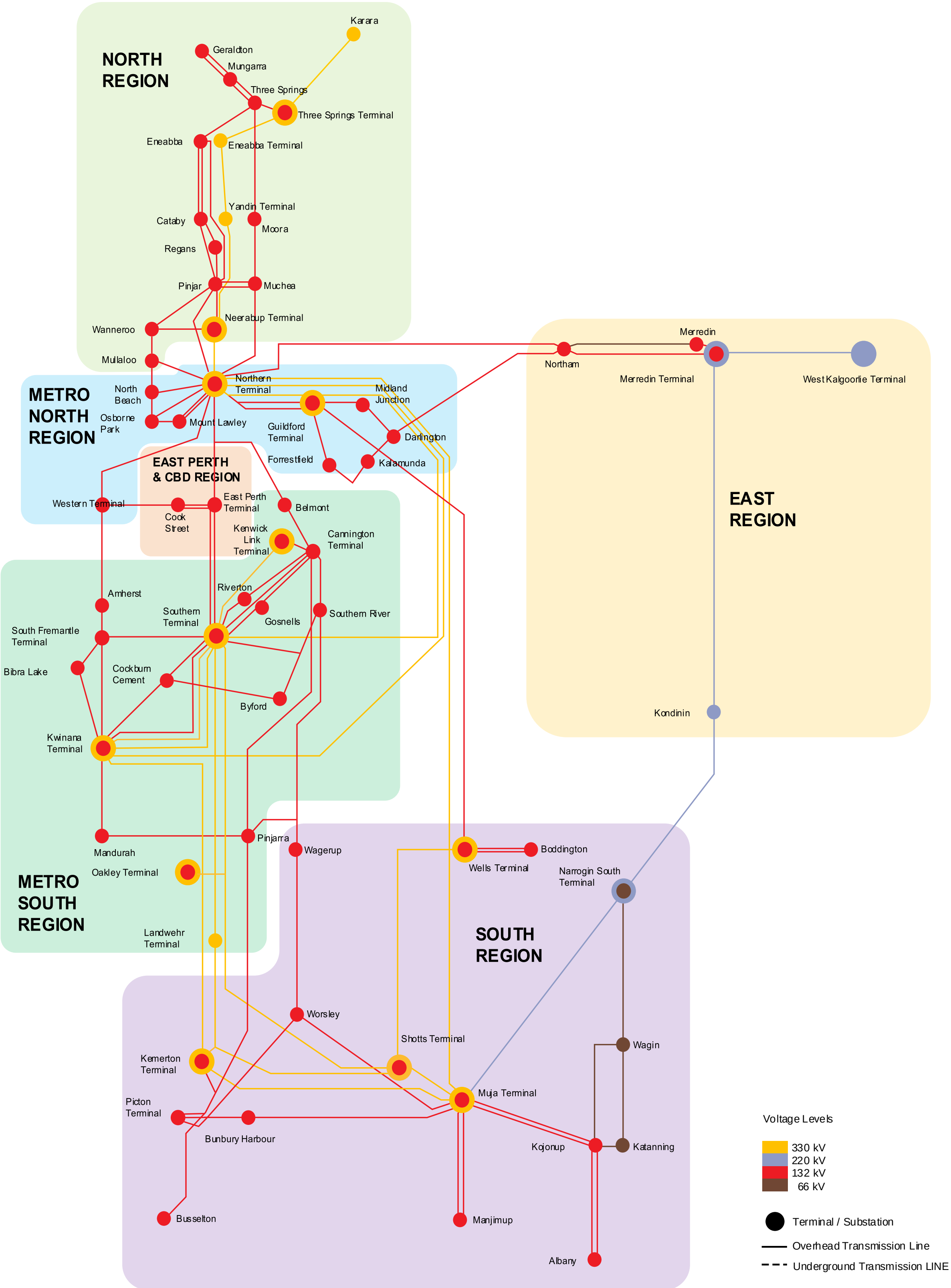

Figure 6: Western Power's transmission network regions

9.1 Network regions

Each of the six Western Power transmission network regions, as shown in Figure 6, are discussed in dedicated sections 10 to 15. Each section includes commentary on the key regional characteristics, such as:

1) geographical boundaries;
2) the type of load and generation mix;
3) overview of network performance; and,
4) commentary about the regions network constraints, opportunities, and key developments, over the study period[32].

9.2 Network opportunities

Alternative options

A list of network opportunities which provide alternative options to alleviate or reduce network constraints and subsequent proposed network augmentation is available in the 'Transmission Opportunities 2024' tab of the Investment Plan 2024 spreadsheet.

The network opportunities and network solutions (for each region) will be explored further during the scoping and planning phases of proposed project lifecycle (and/or existing facilities' studies). If alternative opportunities are found to be not a technically and economically viable, network solutions will be implemented to address the identified network constraints.

Network augmentations

The "Network data 2024" workbook contains forecast and capacity data supporting this TSP and also the Western Power Network Opportunity Map (NOM2024). Accordingly, it should be read in conjunction with the NOM and the TSP reports. For more information relating to what is a network opportunity and how and when to submit an alternative option, please refer to investment spreadsheet data related to the NOM 2024.

[32] Also see detailed Network Data and Investment Plan spreadsheets: Transmission system plan & network opportunity map (westernpower.com.au).

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.

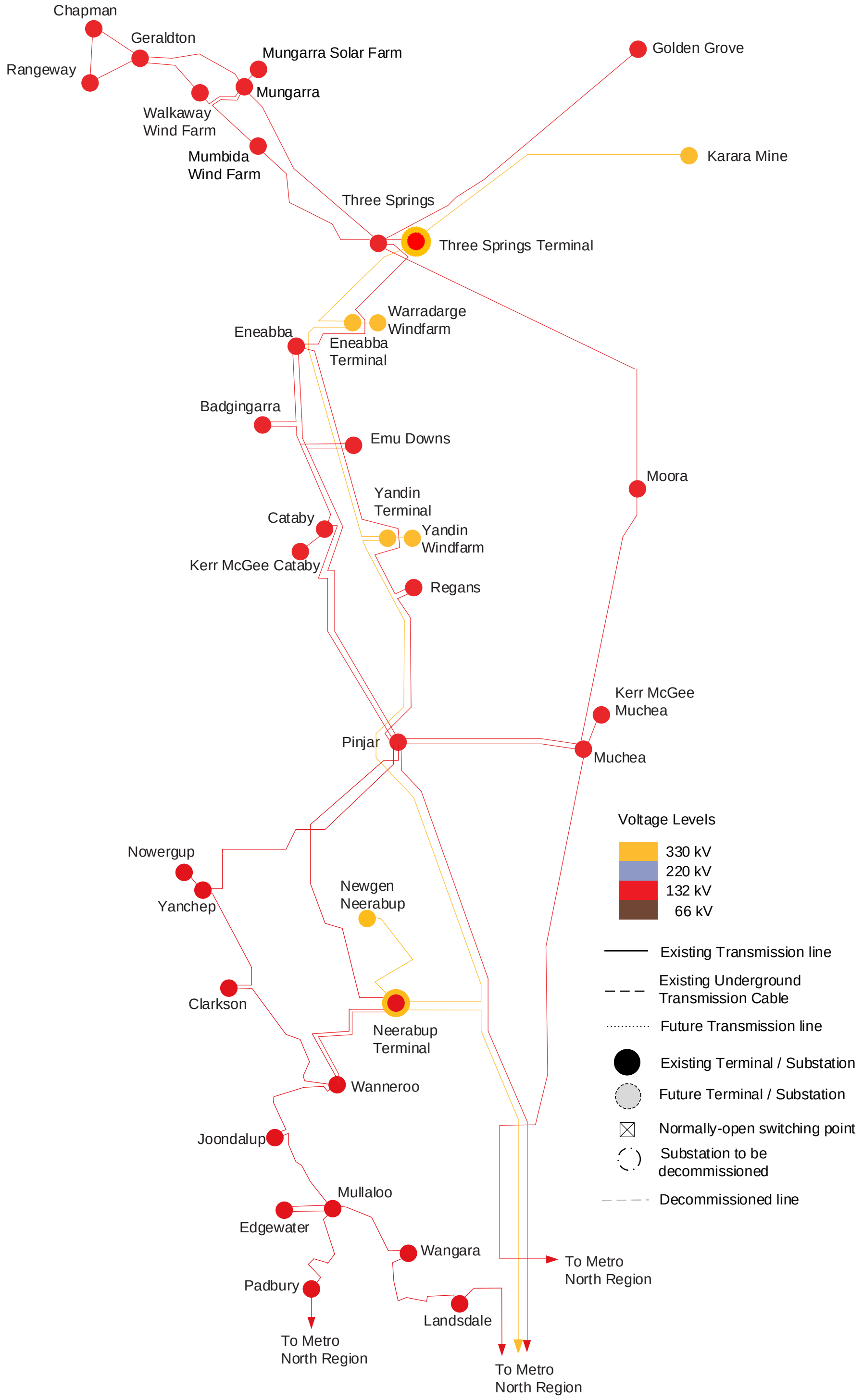

Figure 7: Western Power's North Region – Network Diagram

Western Power's North Region has four terminal stations and 21 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 / Western Power Substations

- Badgingarra – 132 kV
- Cataby – 132 kV
- 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
- Mungarra – 132k kV
- Mullaloo – 132/22 kV
- Mumbida – 132 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

- Edgewater – 132 kV
- Golden Grove – 330 kV
- Kerr McGee Cataby – 132 kV
- Kerr McGee Muchea – 132 kV
- Karara Mine – 330 kV
- Mungarra Power Station – 132kV
- Mungarra Solar – 132 kV
- Mumbida WF – 132 kV
- Nowergup – 132 kV
- Walkaway WF - 132kV
- Warradarge 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 in the order of 800 MW of renewable generation in the region. In addition, there is also significant gas-fired generation at Neerabup terminal, Pinjar and Mungarra. 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 delivered. There are further transmission investments under development to increase network capacity and these are outlined broadly in the TXIP, as discussed in section 3.

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 connected at Warradarge and Yandin on the 330 kV network and at Badgingarra on the 132 kV network. Despite network constraints in the region, legacy arrangements have enabled the connection of the windfarms under an interim constrained network access regime prior to October 2023. These constraints will now be managed in accordance with the dispatch engine under WEM constrain access market arrangements, and other applicable WEM operational procedures.

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).

Import Boundaries

Figure 8 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 5.

Table 5: Thermal import boundaries characteristics – North Region

Characteristics	Import Boundaries – Pre-NREP			
	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

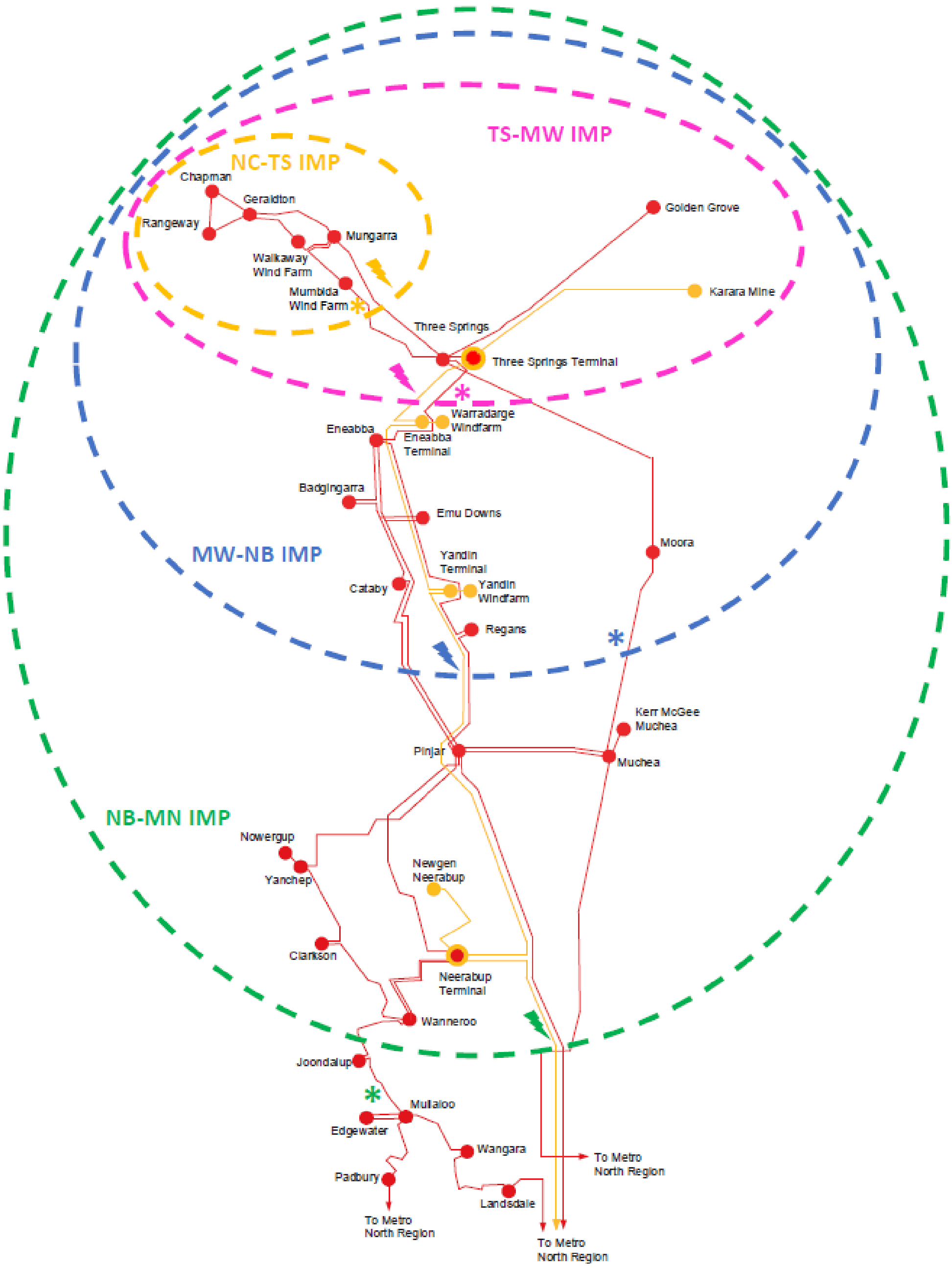

Figure 8: Existing Network thermal import boundaries in the North Region

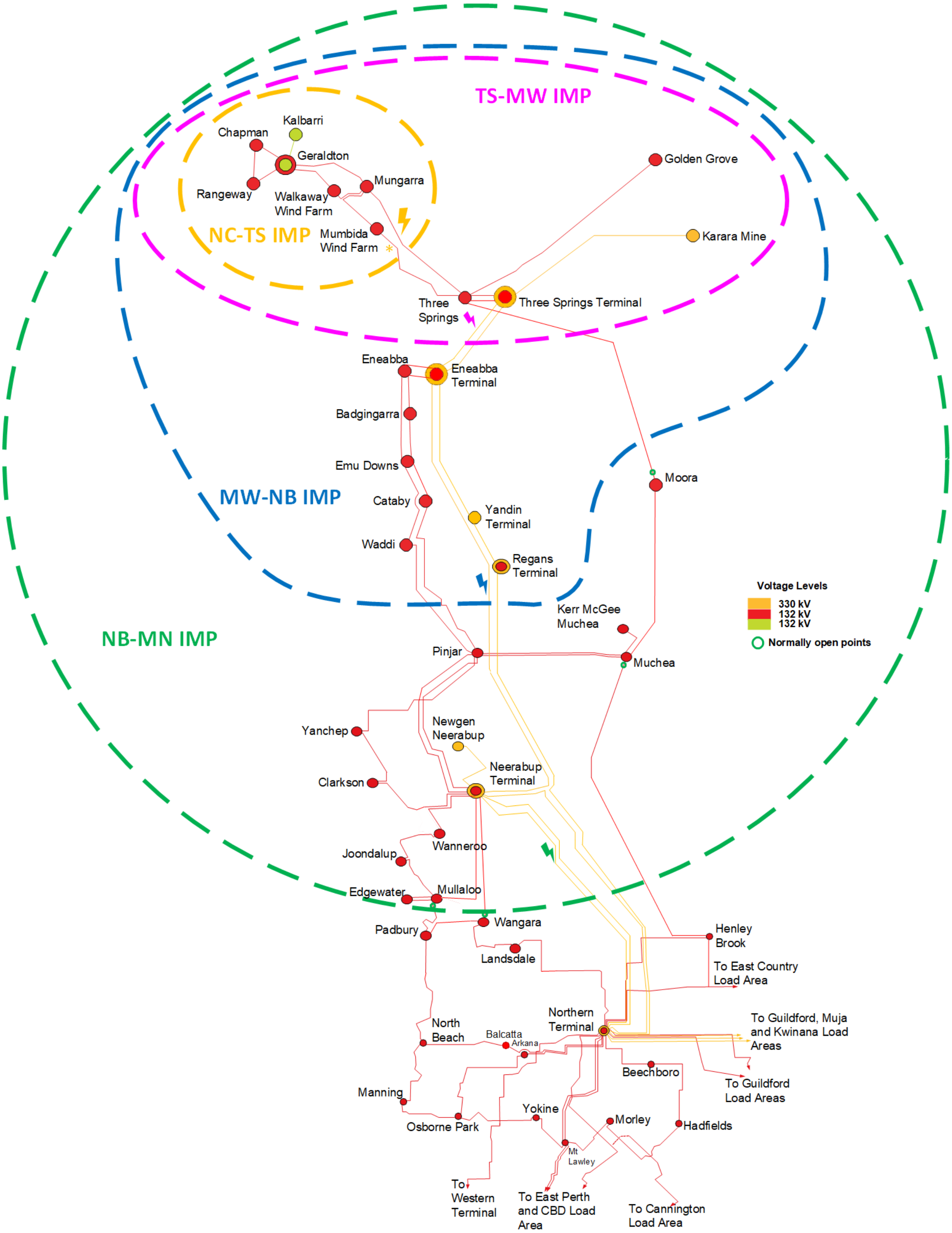

Figure 9:Network thermal import boundaries in the North Region - Post North expansion

Figure 8 and Figure 9 show the thermal import boundaries in the North Region – pre and post envisioned TXIP works. The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 10 to Figure 14.

Table 6 Thermal import boundaries characteristics – North Region - Post TXIP

Characteristics	Import Boundaries – Pre-NREP			
	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

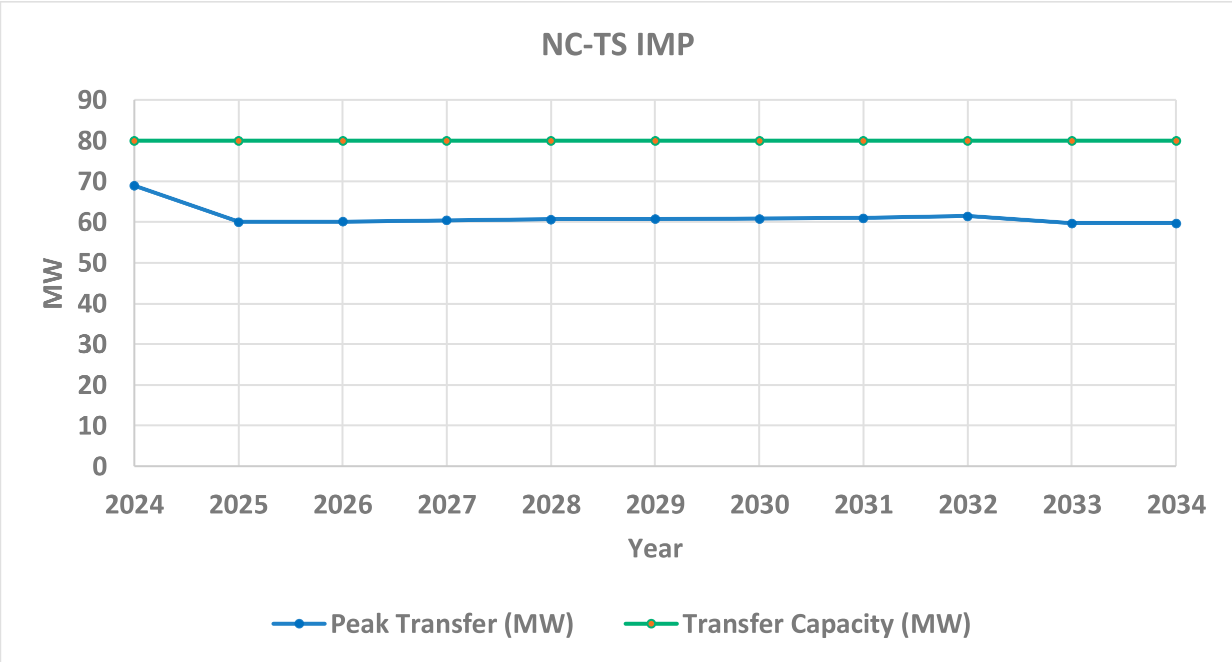

Figure 10: Expected transfer and transfer capacity in NC-TS IMP boundary – peak demand

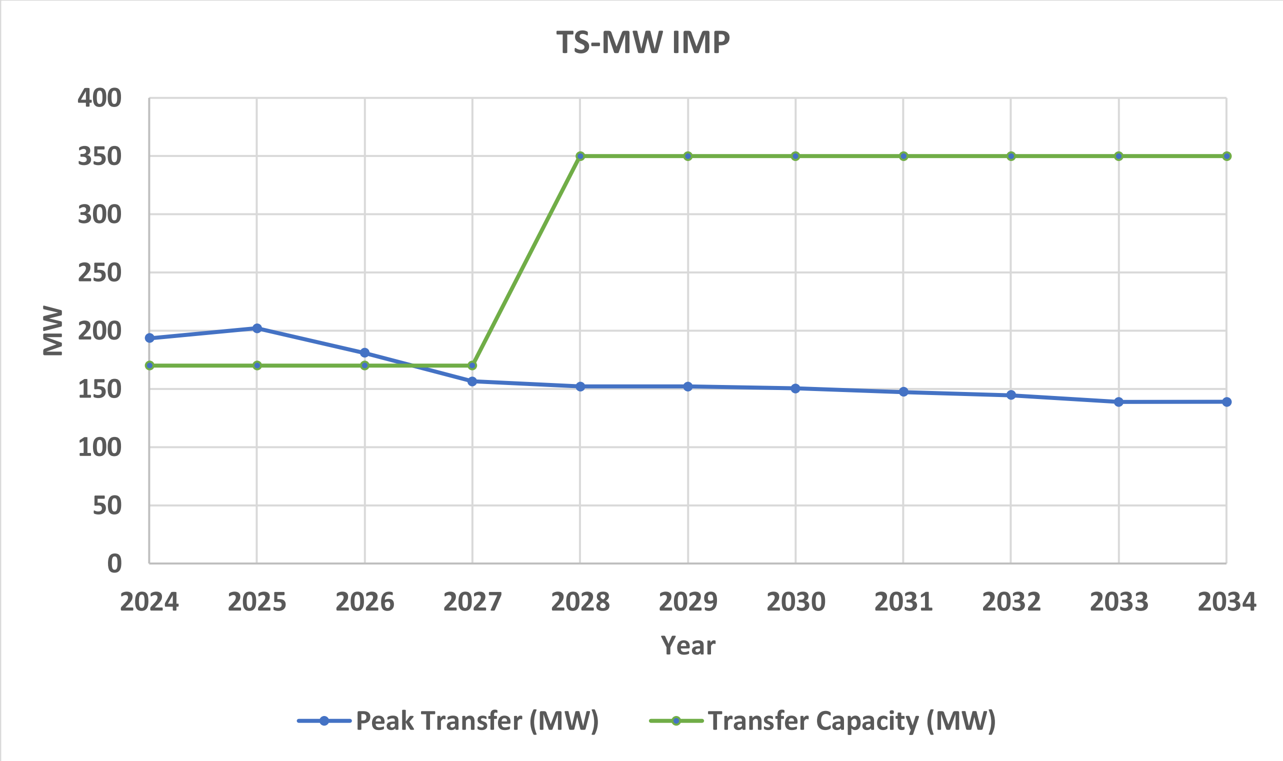

Figure 11: Expected transfer and transfer capacity in TS-MW IMP boundary – peak demand

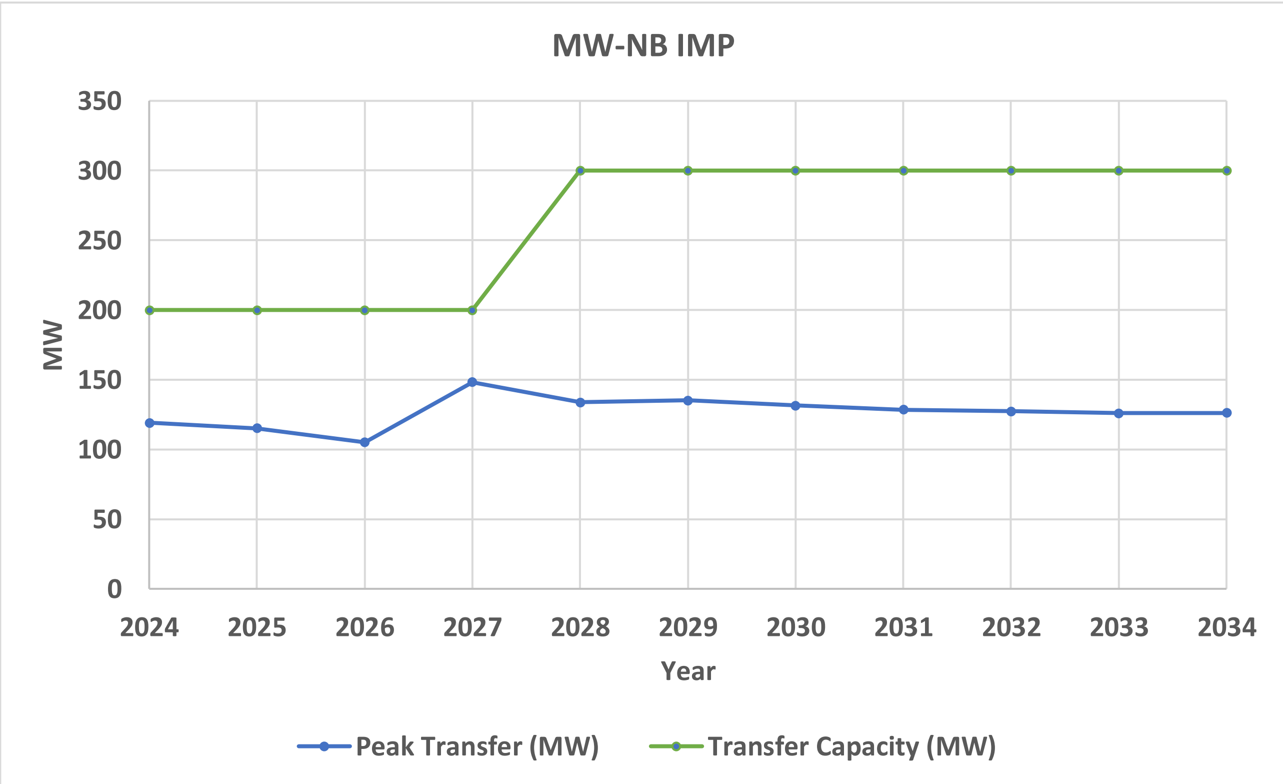

Figure 12: Expected transfer and transfer capacity in TS-MW IMP boundary – peak demand

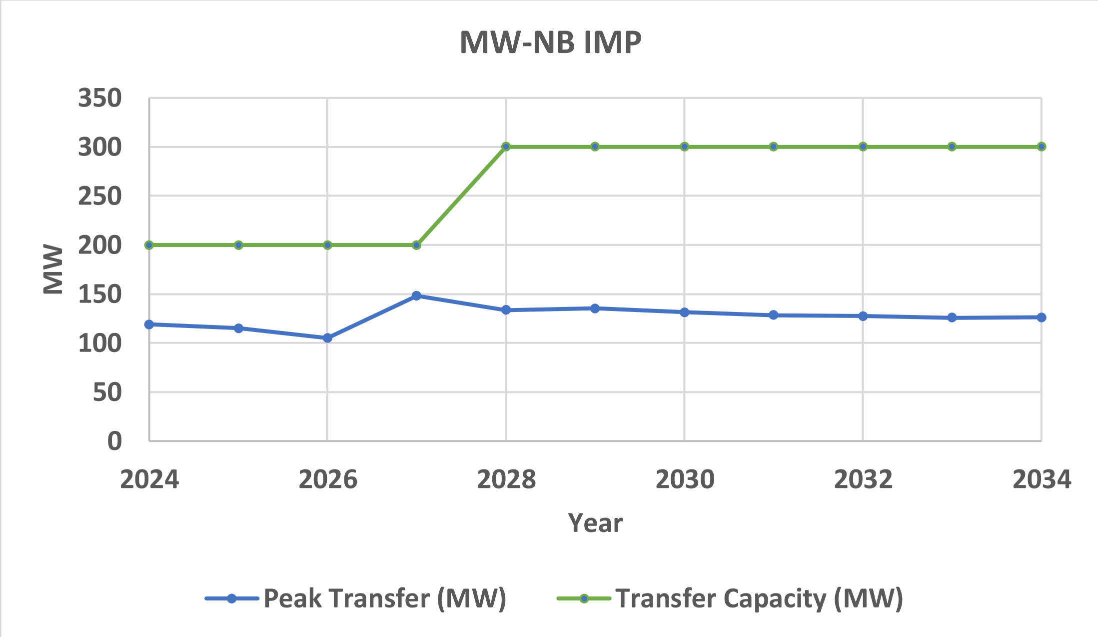

Figure 13: Expected transfer and transfer capacity in MW-NB IMP boundary – peak demand

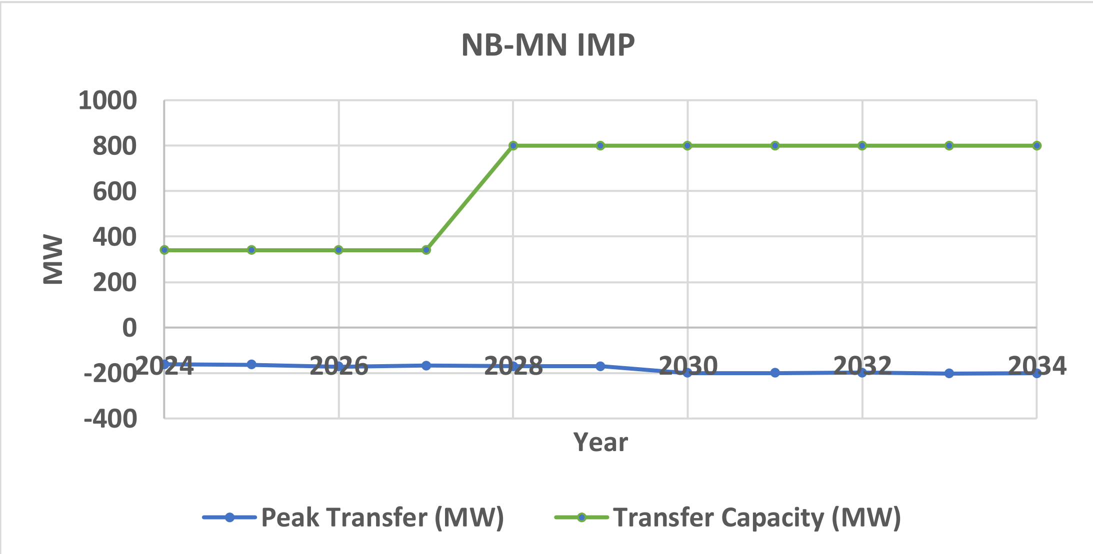

Figure 14: Expected transfer and transfer capacity in NB-MN IMP boundary – peak demand (noting step change, pre/post TXIP works, c. 2027/28)

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 (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 14 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 7.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 17 to Figure 20.

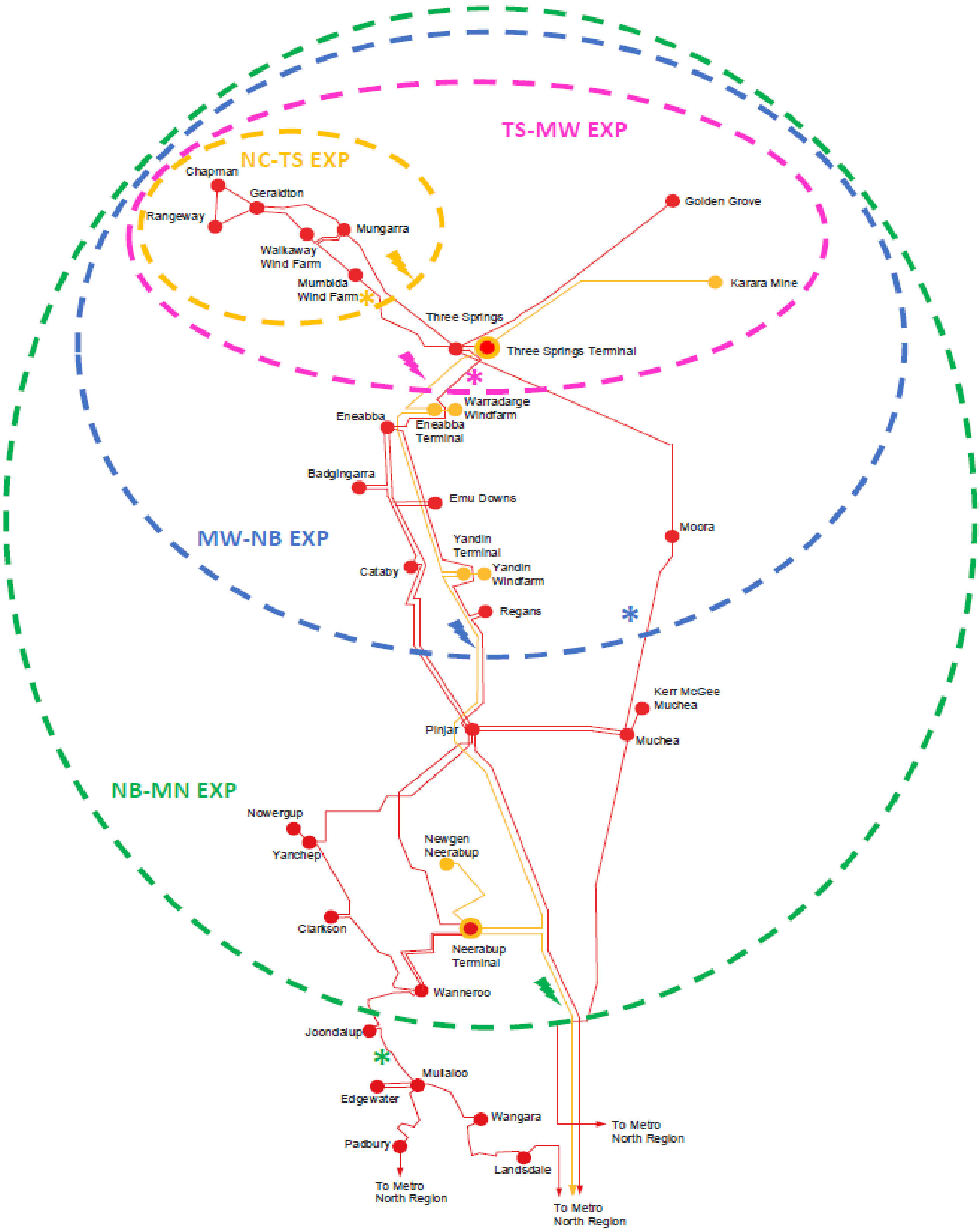

Figure 15: Network thermal export boundaries in the North Region

Table 7: Thermal export boundaries characteristics – North Region

Characteristics	Export Boundaries – Pre NREP			
	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

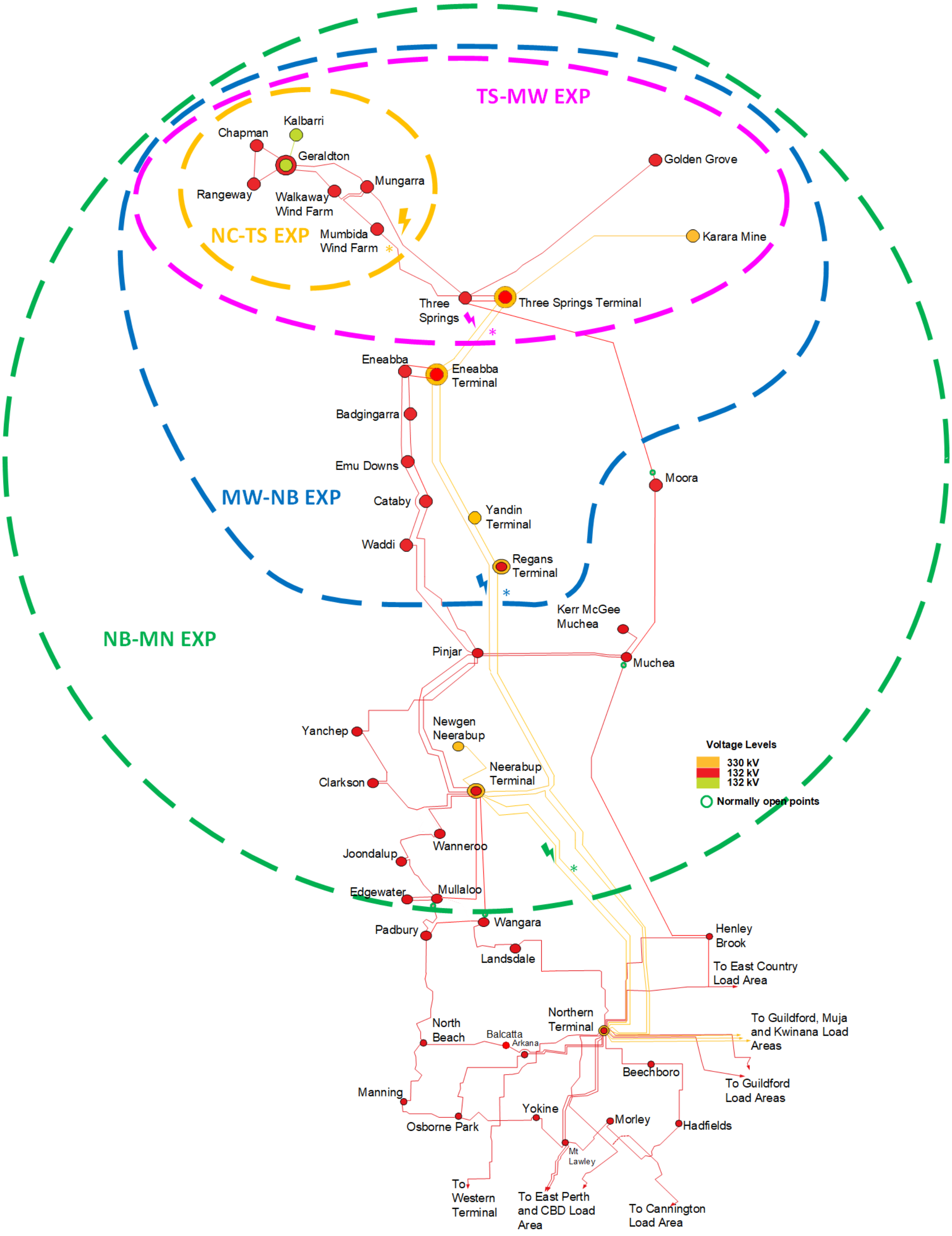

Figure 16: Network thermal export boundaries in the North Region - Post TXIP North

Table 8 Thermal export boundaries characteristics – North Region - Post NREP

Characteristics	Export Boundaries – Post NREP			
	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	Northern Terminal to Regans 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 Terminal to Three Springs Terminal 330 kV line	Neerabup Terminal to Eneabba Terminal 330 kV line	Northern Terminal to Neerabup Terminal 330 kV line

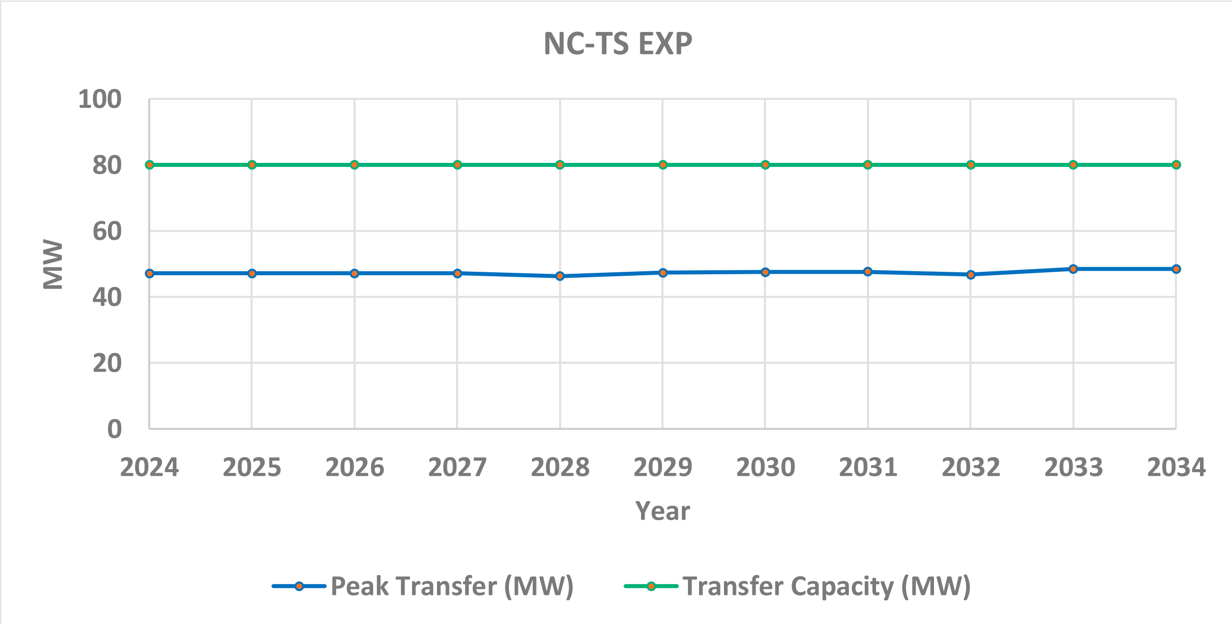

Figure 17: Expected transfer and transfer capacity in NC-TS EXP boundary – peak demand

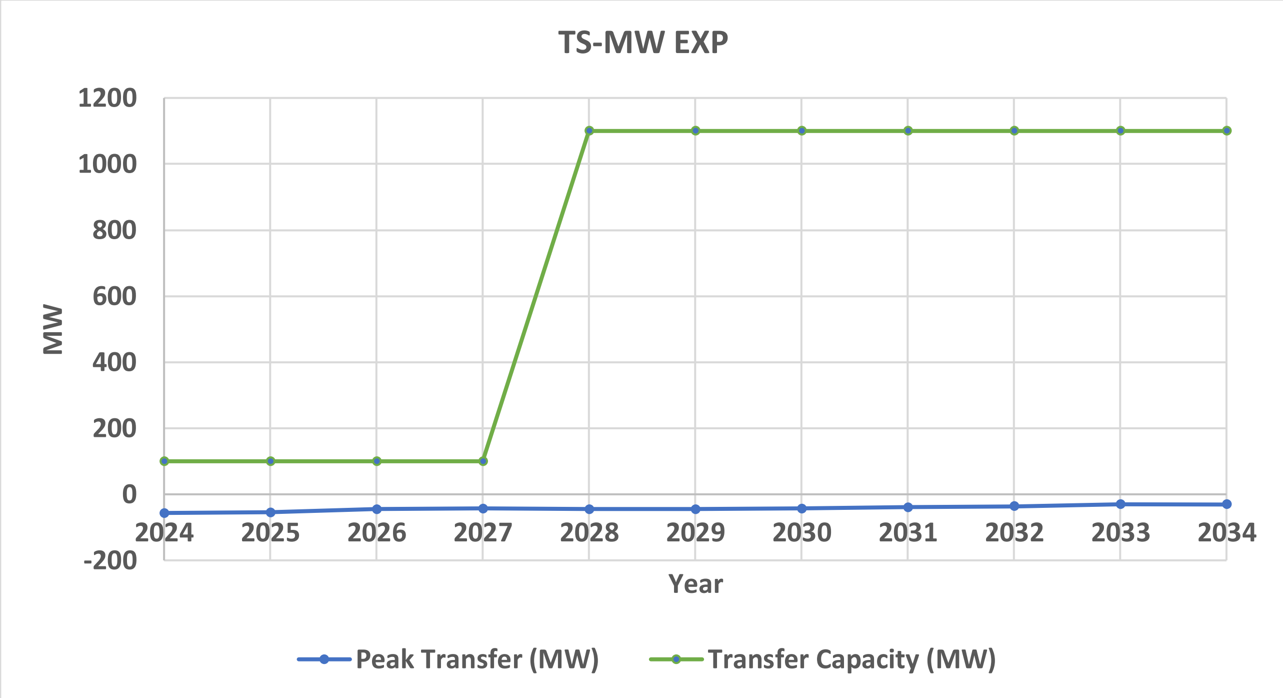

Figure 18: Expected transfer and transfer capacity in TS-MW EXP – peak demand

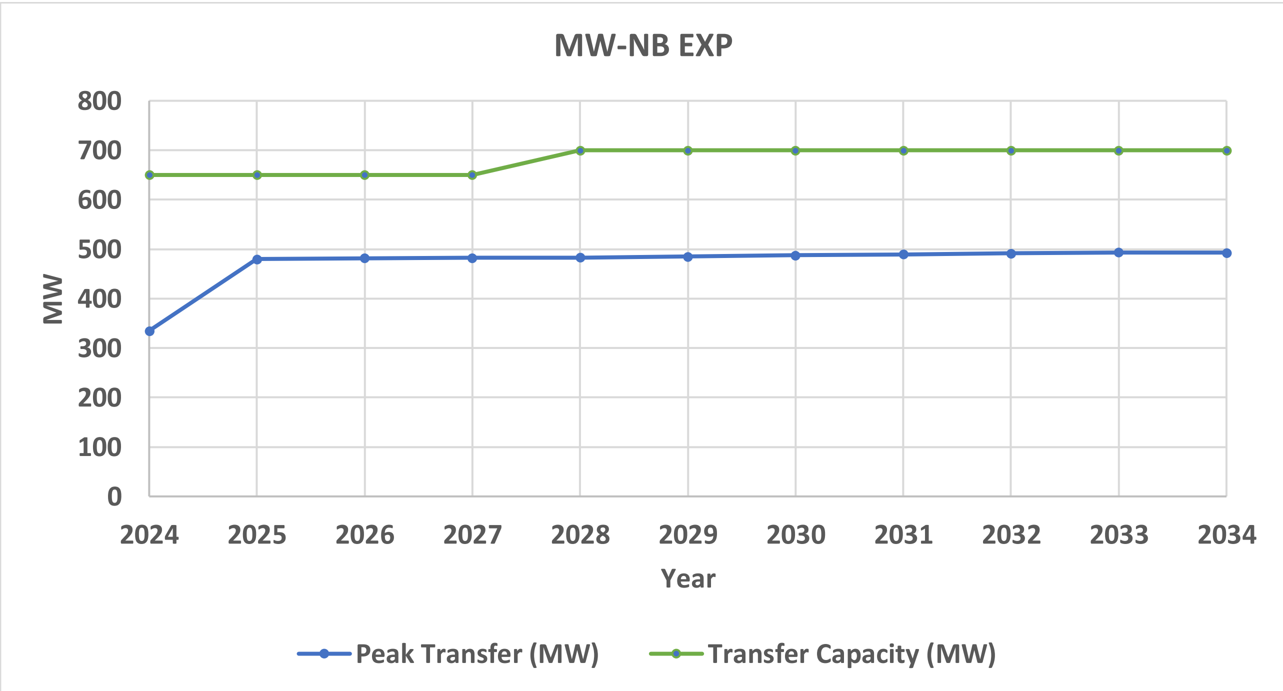

Figure 19: Expected transfer and transfer capacity in MW-NB EXP boundary – peak demand

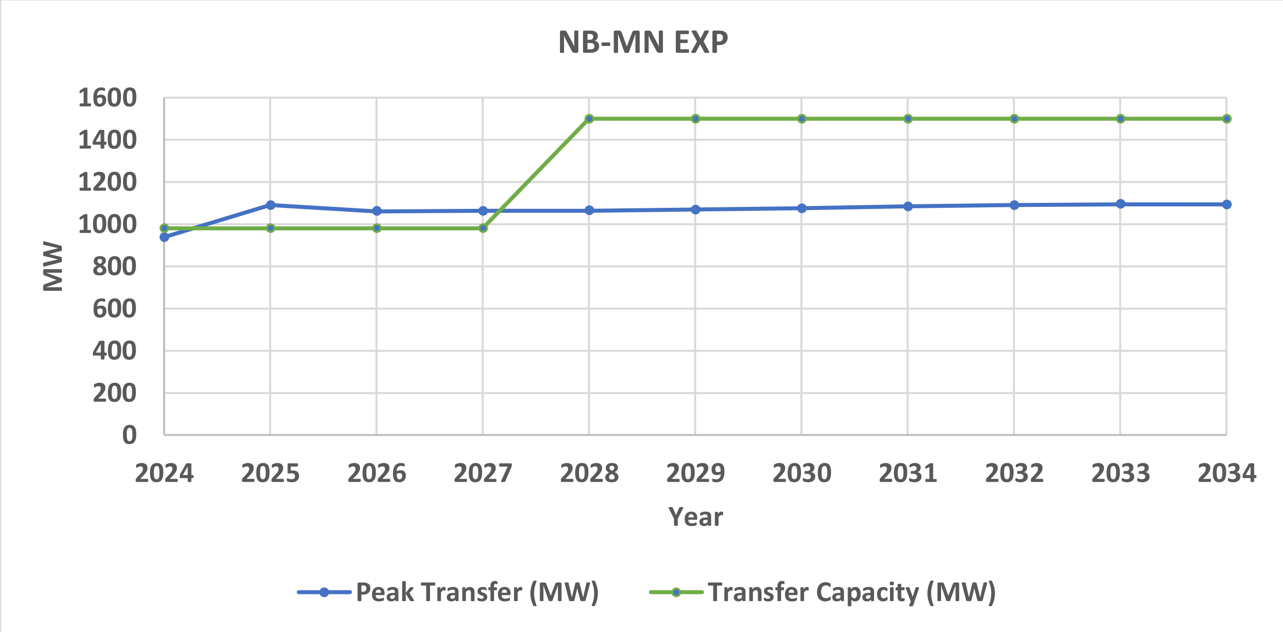

Figure 20: Expected transfer and transfer capacity in NB-MN EXP boundary – peak demand

The above figures illustrate that new generation connection for the NC-TS and MW-NB boundaries are very limited and hence the proposed network augmentation under development to provide additional capacity. The export capacity through NB-MN boundary is predicted to be exceeded with the connection of large new scale generators. With abundant renewable fuel resources in the area, new generation connections are likely to increase congestion issues within this region prior to the completion of the network augmentations.

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.

The above peak transfer versus transfer capacity figures illustrates the available import and export capacity within northern area boundaries for the duration of the study period. The introduction of proposed TXIP works provides additional capacity, except for NC-TS. The remaining boundaries capacity boost are evident by the step change in the transfer capacity values by 2028.

10.3.2 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[33] from Three Springs.

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

10.4 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 10.3.1 Thermal Capacity - Boundaries.

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 the congestion issues within the region and drive network augmentations. To provide additional bulk power transfer capacity from the North Region into the Perth Metro area.

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 21 shows the transmission system in this region.

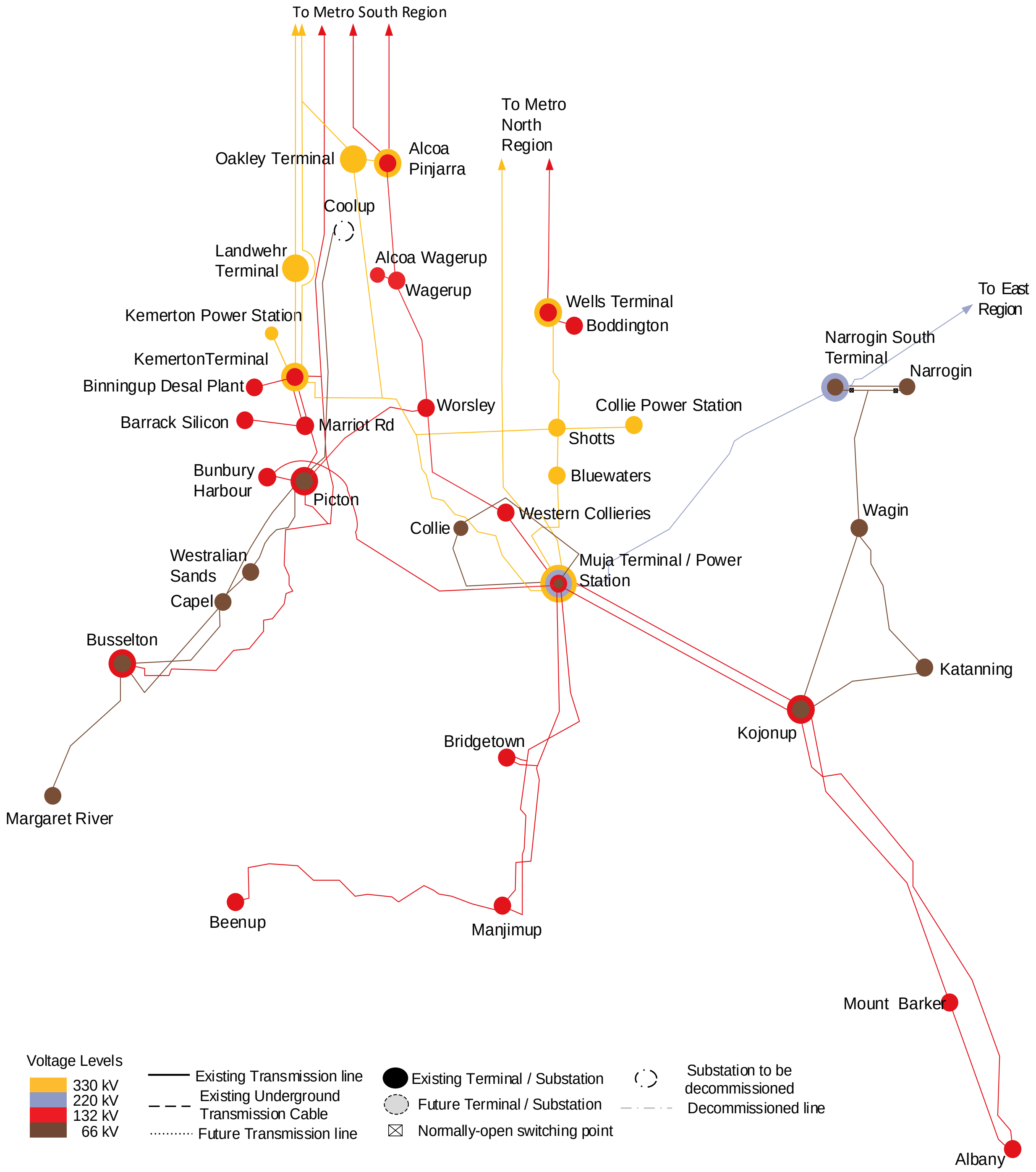

Figure 21: Western Power's South Region – Network Diagram

The South Region has 10 terminal stations and 18 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
- Busselton Terminal – 132/66 kV
- Kemerton Terminal – 330/132 kV
- Kojonup Terminal – 132/66 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 kV
- Shotts Terminal – 330 kV
- Wells Terminal – 330/132 kV

Zone Substations / Western Power 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*[34]
- Katanning – 66/22 kV
- Kojonup –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
- Picton – 66/22 kV
- Wagerup – 132/22 kV
- Wagin – 66/22 kV

Customer Substations

- Alcoa Pinjarra – 132 kV
- Alcoa Wagerup – 132 kV
- Collie Power Station – 330 kV
- Binningup Desalination Plant – 132 kV
- Bluewaters Power Station – 330 kV
- Boddington – 132 kV
- Kemerton Power Station – 330 kV
- Wagerup – 330 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.

[34] Coolup 66 kV substation was decommissioned in late 2022.

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.

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 in voltage control and performance, both within the region and in the wider SWIS, as well as reducing overall system inertia and strength. This is offset to some extent by development of several large battery energy storage projects which are planned in the region.

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. There is a continued interest in large scale battery storage and renewable generation projects in the region.

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 22 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 23 to Figure 26.

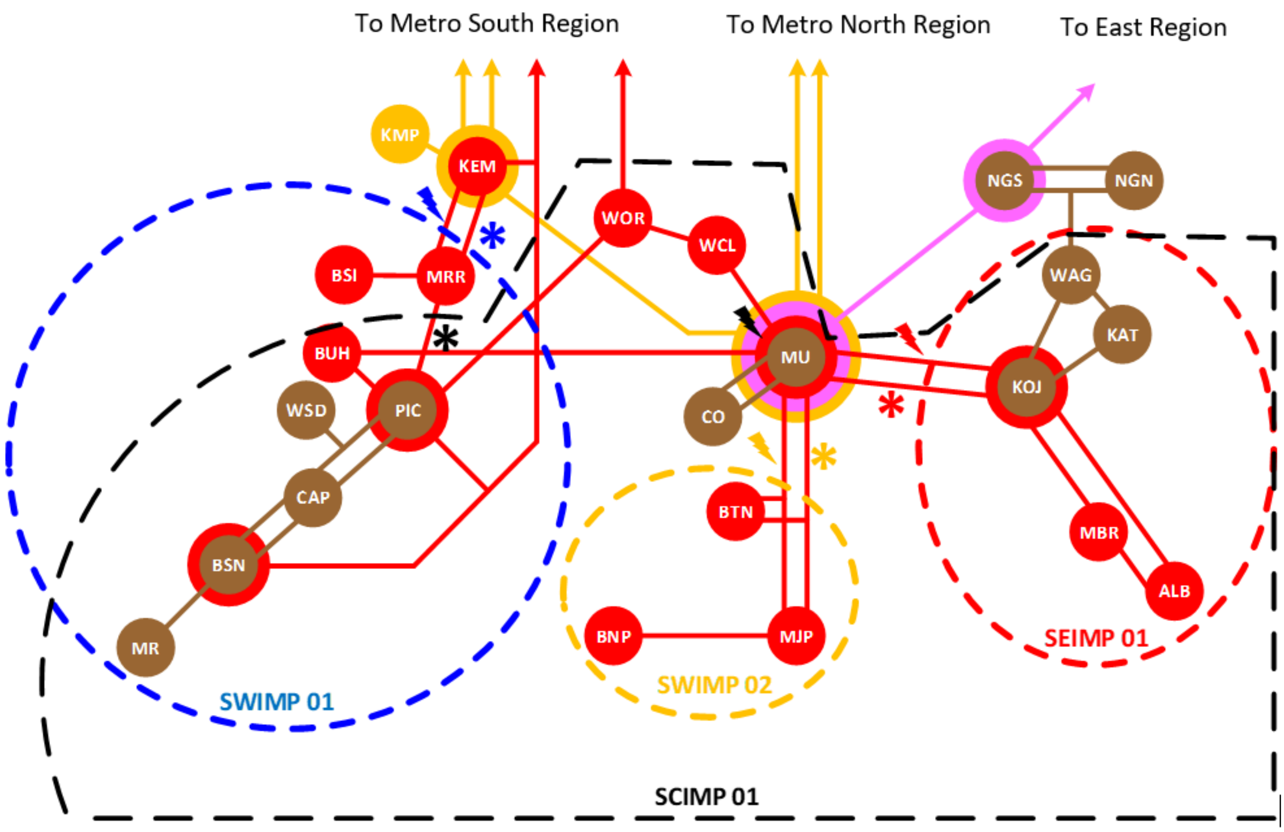

Figure 22: Network import boundaries in the South Region

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

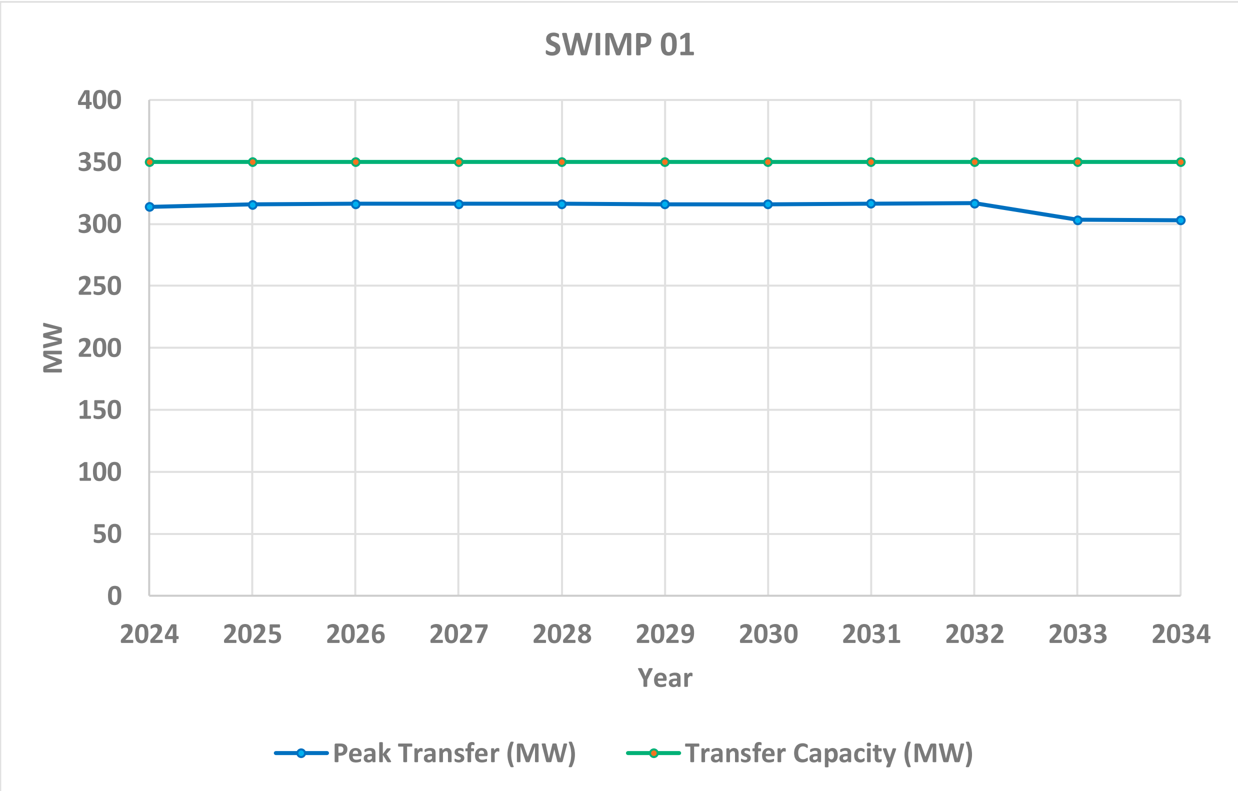

Figure 23: Expected transfer and transfer capacity in SWIMP 01 boundary – peak demand

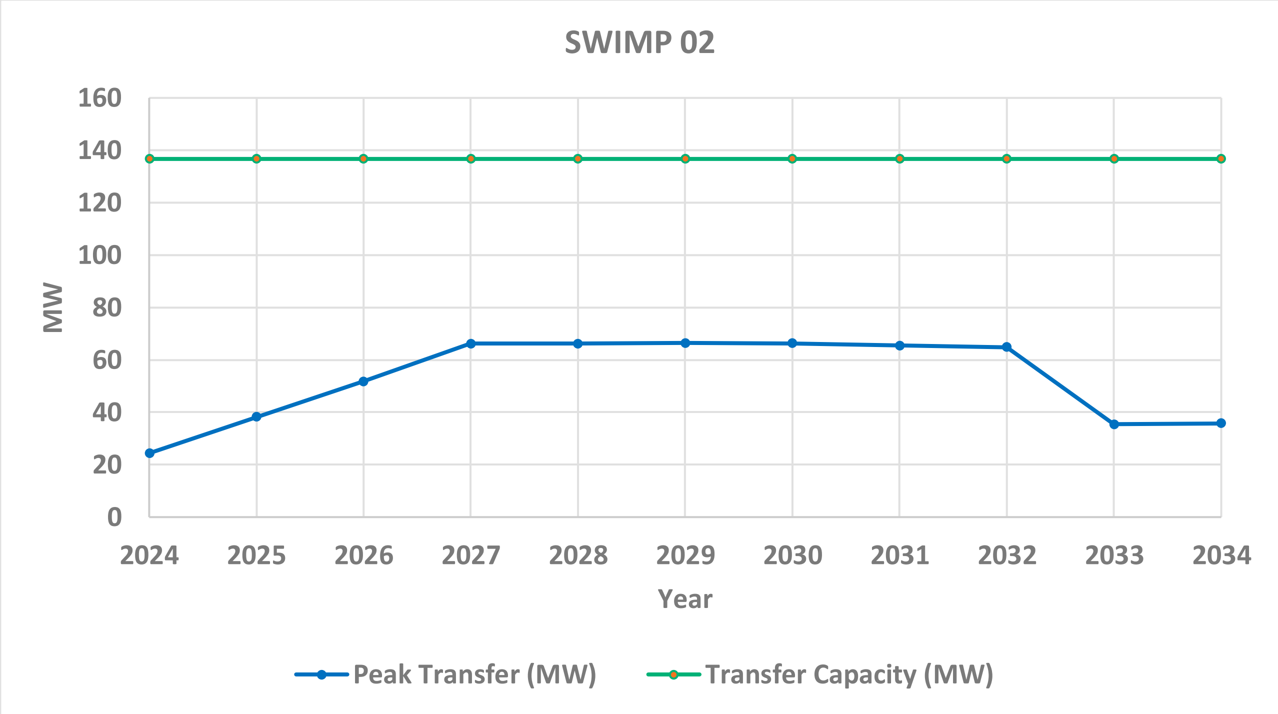

Figure 24: Expected transfer and transfer capacity in SWIMP 02 boundary – peak demand

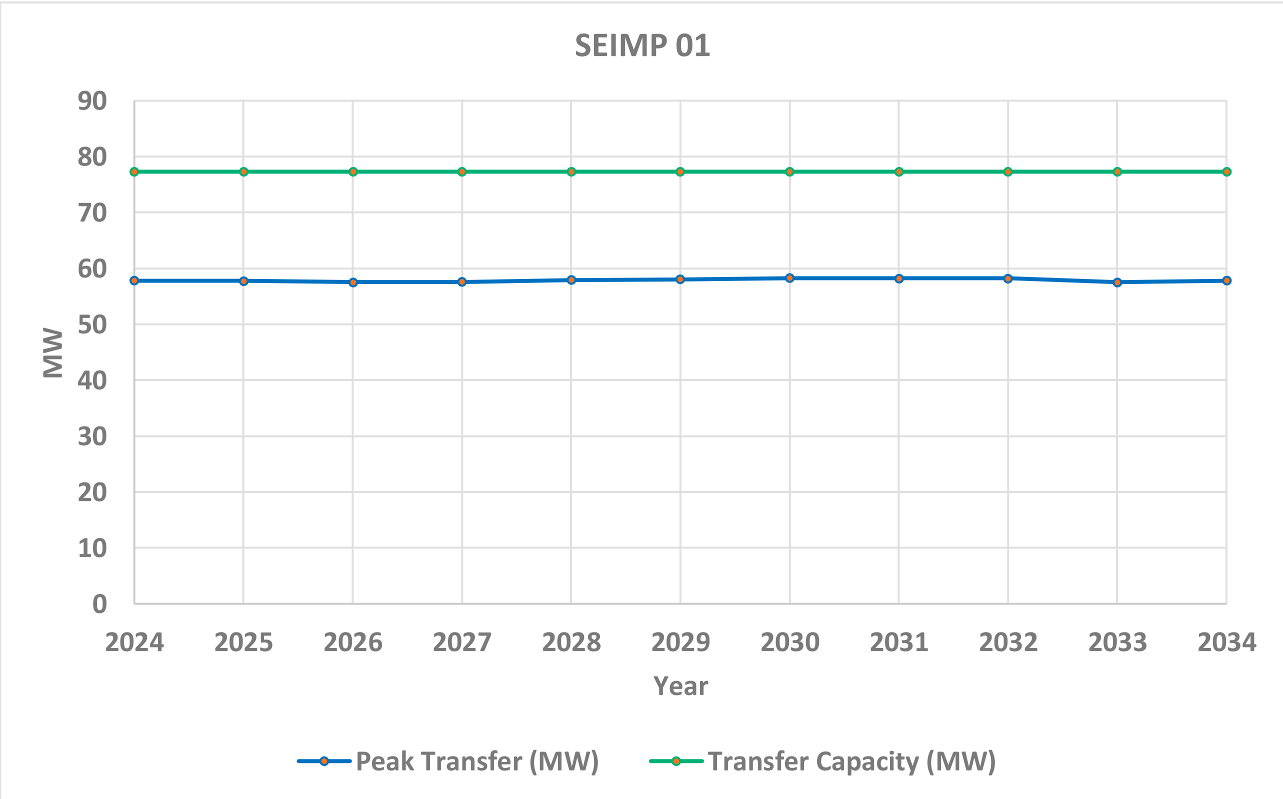

Figure 25: Expected transfer and transfer capacity in SEIMP 01 boundary – peak demand

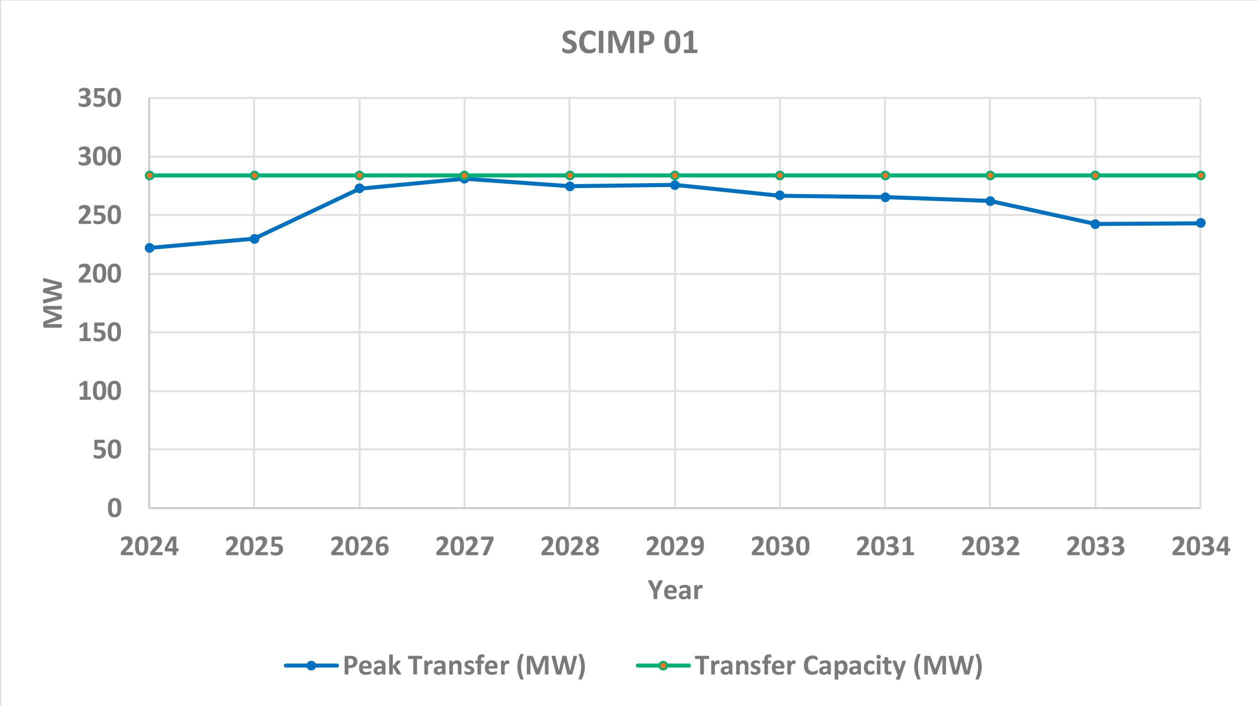

Figure 26: Expected transfer and transfer capacity in SCIMP 01 boundary – peak demand

As observed in the above figures, the available import capacity in SCIMP 01 is limited. This is a N-1-1 contingency due to the outage of both MU BTT1 & BTT2, which is a planned contingency outage at 80% of the expected peak load. This can be managed by careful selection of the planned outage 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 SWIMP 01 and SEIMP 01 boundaries will be limited (30 – 40 MW) without network augmentation.

Export Boundaries

Figure 27 shows the network export boundaries in the South Region. These boundaries are defined using the worst contingency ( ) and the worst overload circuit (*) as shown in Table 10.

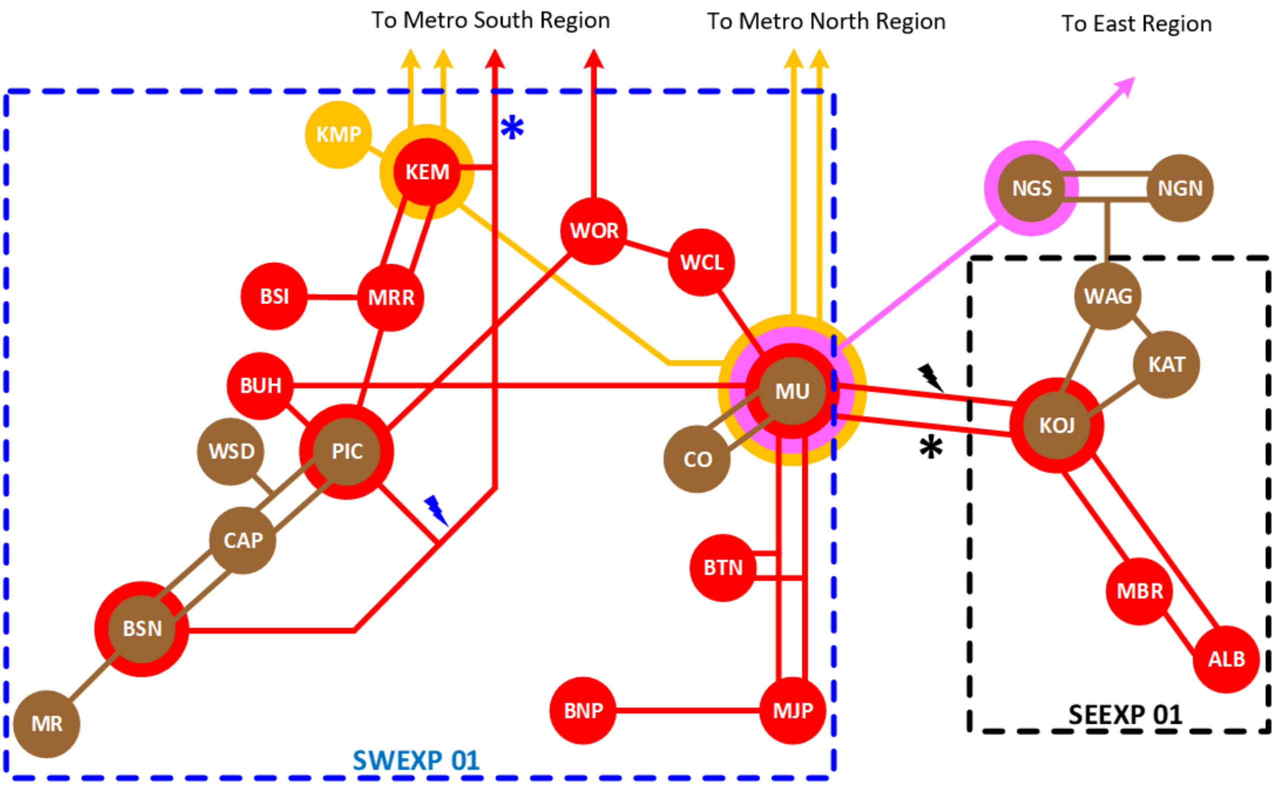

Figure 27: Network export boundaries in the South Region

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 export boundaries across the study period is shown in Figure 28 and Figure 29.

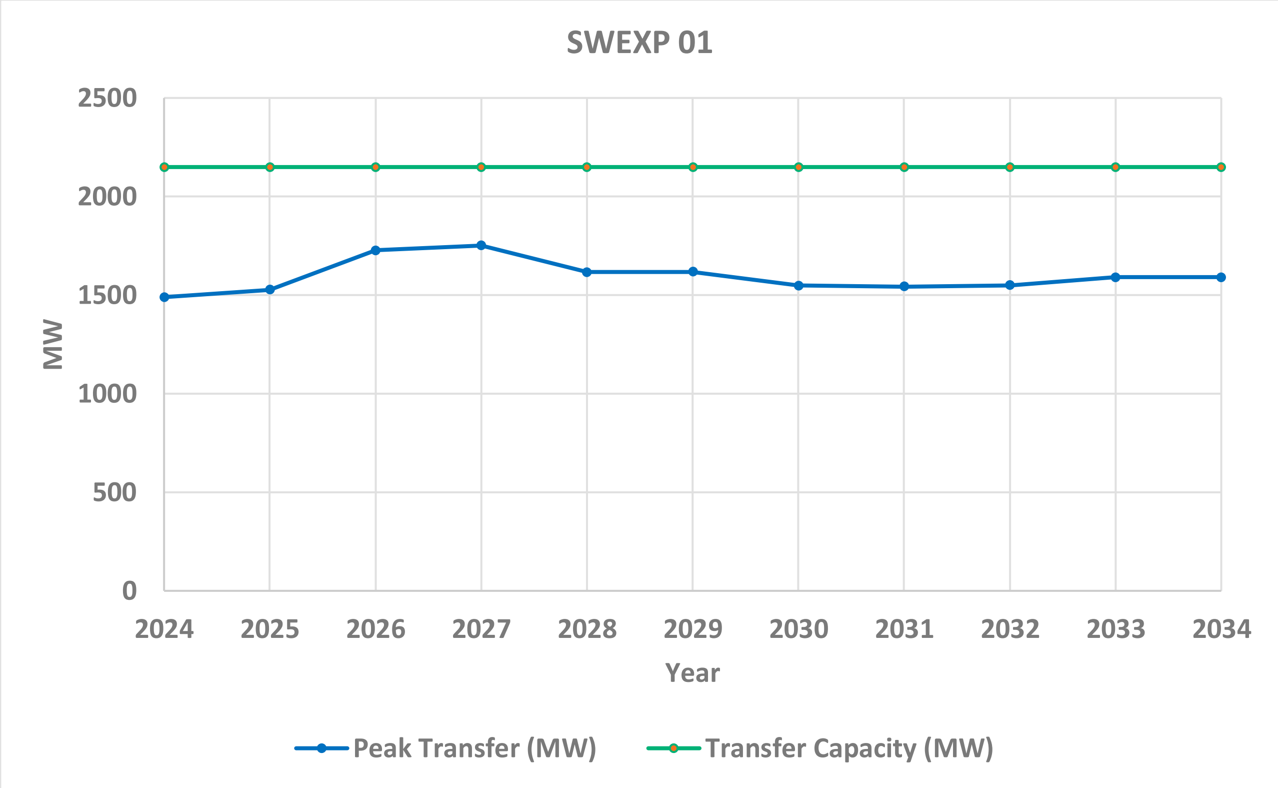

Figure 28: Expected transfer and transfer capacity in SWEXP 01 boundary – peak demand

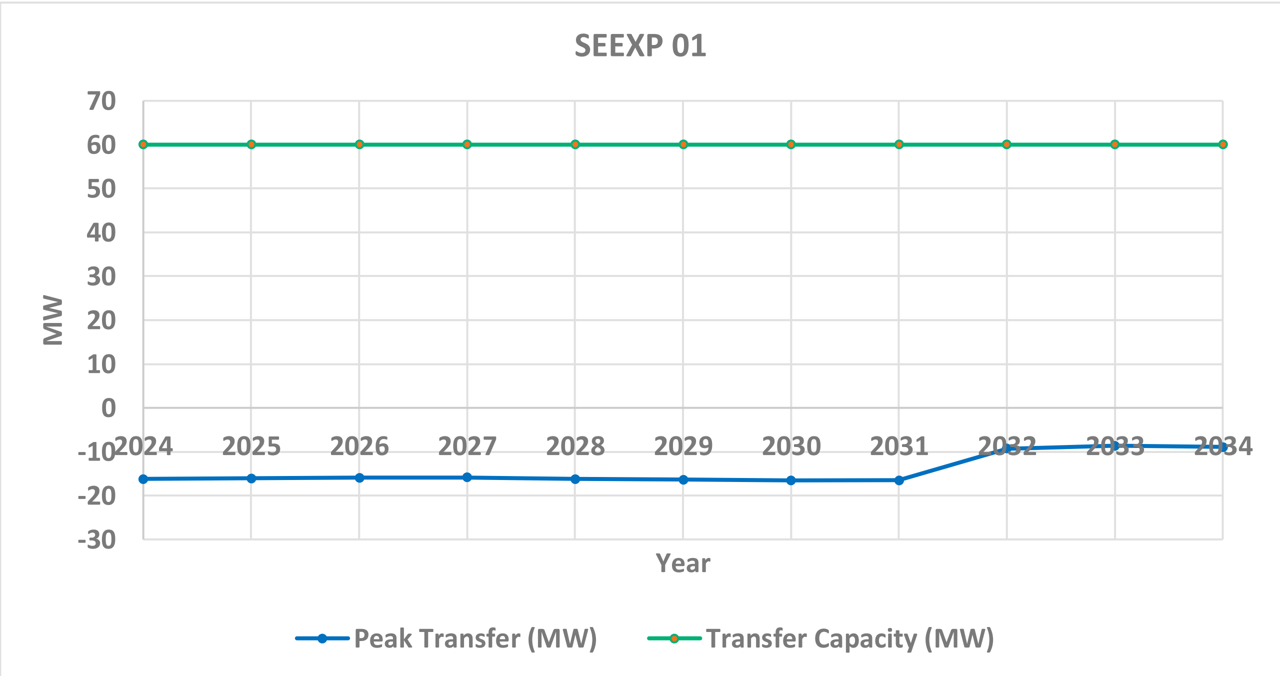

Figure 29: Expected transfer and export transfer capacity in SEEXP 01 boundary – peak demand

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, Collie Power Station by 2027 and Muja D units by 2029, this is offset by proposed BESS projects connecting across the study period. 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.

11.4 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 challenges in the area, particularly as these units are critical in providing voltage control within and external to the region and contribute a sizeable 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.

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 30 shows the transmission system in the region.

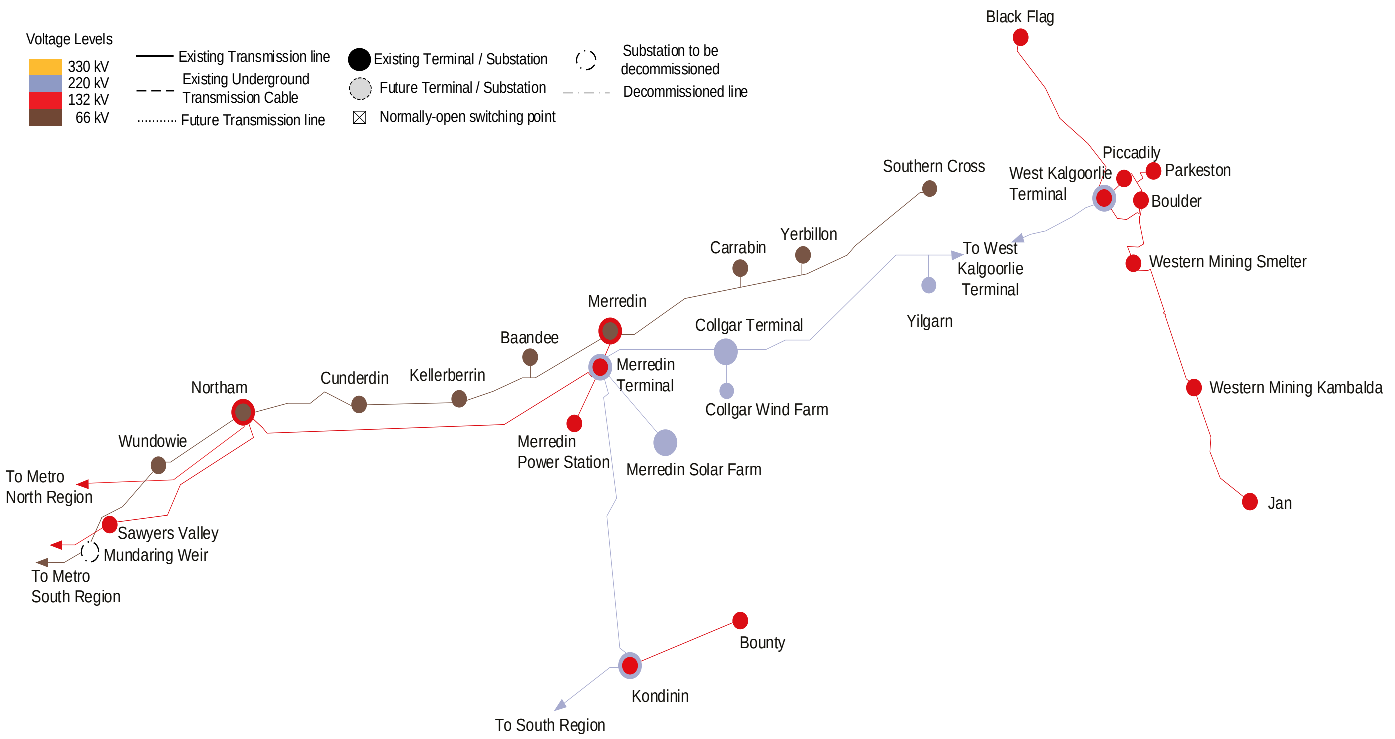

Figure 30: Western Power's East Region – Network Diagram

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

Zone Substations / Western Power Substations

- Baandee – 66 kV
- 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[35]
- 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
- Wundowie – 66/22 kV
- Yerbillon – 66/0.44 kV
- Yilgarn – 220/33 kV

Customer substations

- Collgar Wind Farm – 220 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
- Merredin Solar Farm – 220 kV

[35] MW load transferred to SVY, 66kV energised

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. Industrial load decarbonisation is increasing the level of connection enquiries in this region.

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. Traditionally the East Country load has not had local generation, however with the entrants' generations such as Collgar Wind Farm, Merredin Solar Farm and Merredin Power Station, the Region became a net generation exporter under some conditions.

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 designed to an N-0 security 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 transmission overhead line reinforcement options in Kalgoorlie and the Goldfields, many protection and control schemes have been installed. 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

Steps have been taken in 2023/24 for improving the reliability of electricity supply in the Goldfields Region. Work is underway for acquiring a Non-Co-optimised Essential System Services (NCESS) for up to 150MW of reliability and system strength services for the EGF region. That is, if an outage occurs on the main 220kV transmission line (see section 12.3.2).

New load connections in the region have historically been challenging due to network limitations that arise on 220 kV supply when assessing connections under an (historical) 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.

To further support the connection of both load and generation customers at part of the transition to net zero emissions there are further network investment proposed in the Eastern Region to increase capacity, see section 4.3.

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 31 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 11.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 32 to Figure 34.

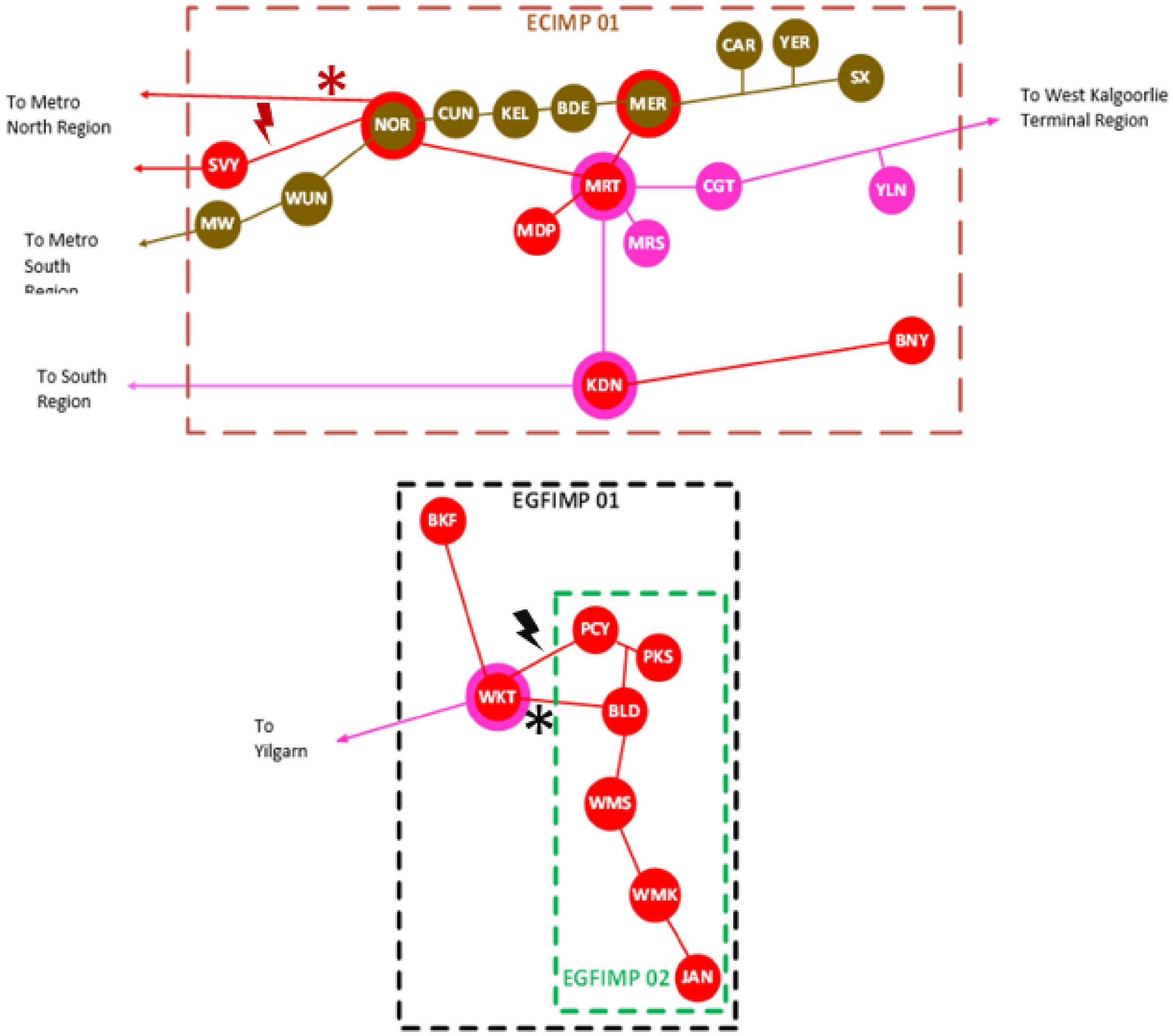

Figure 31: Network import boundaries in the East Region

Table 11: 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

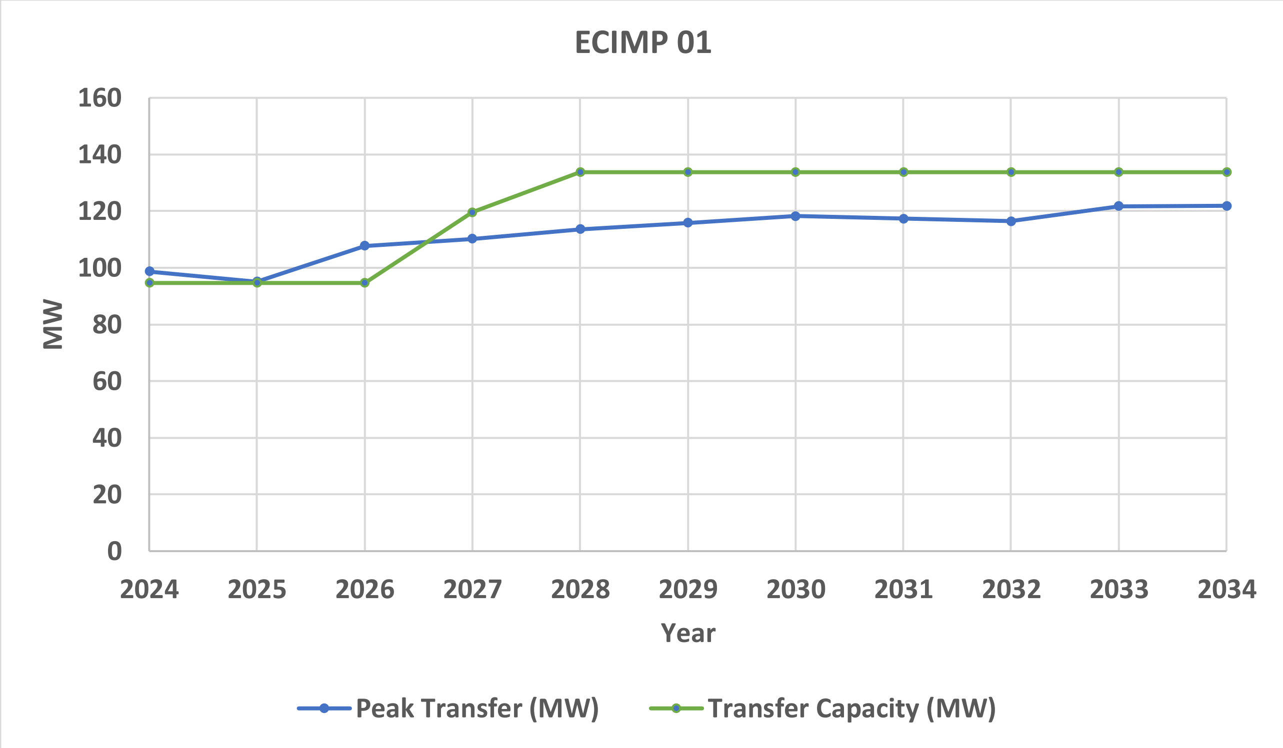

Figure 32: Expected transfer and transfer capacity in ECIMP 01 boundary – peak demand

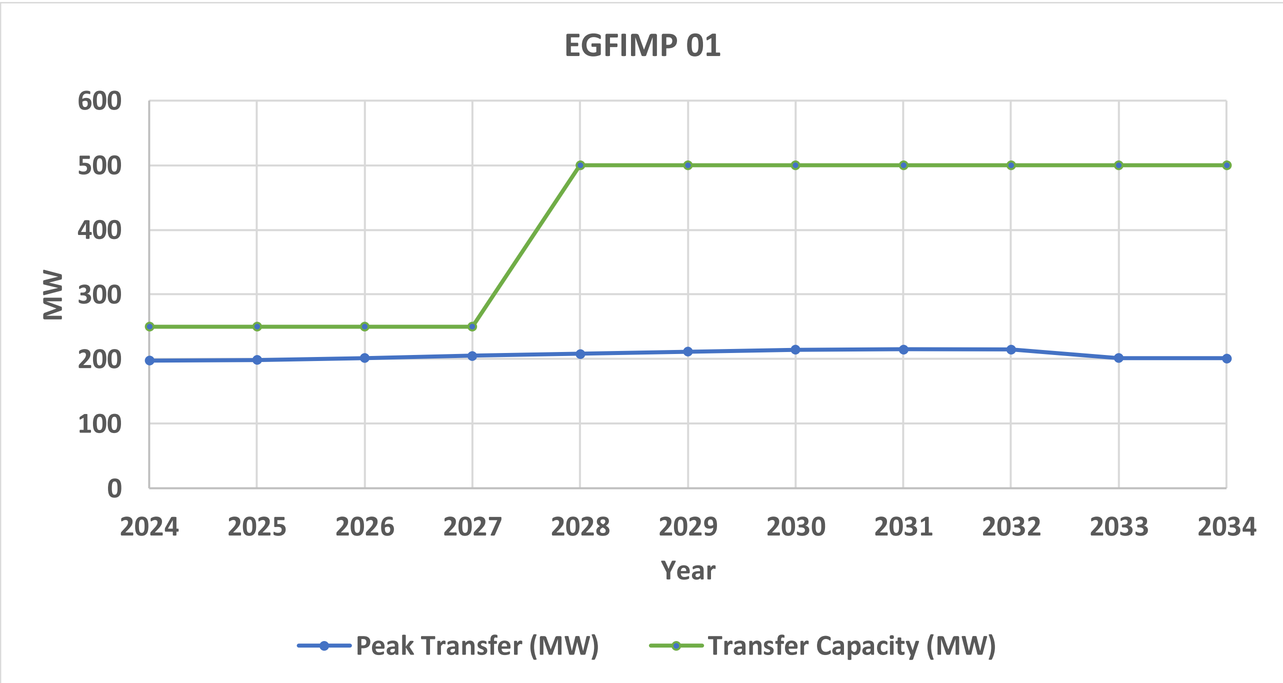

Figure 33: Expected transfer and transfer capacity in EGFIMP 01 boundary – peak demand

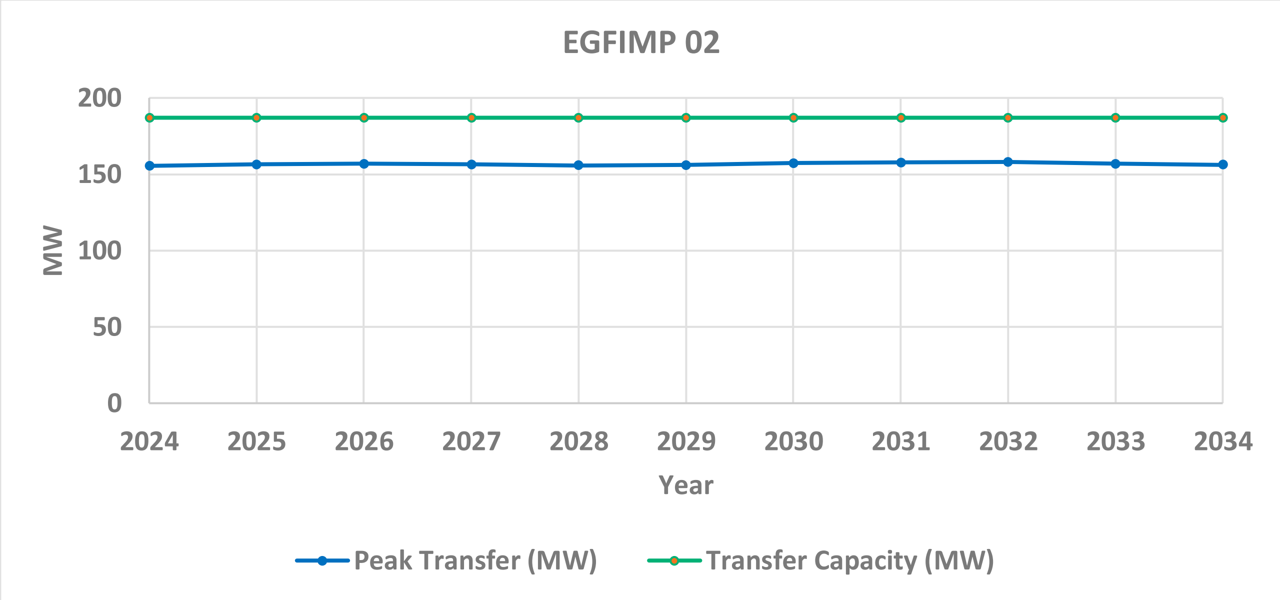

Figure 34: Expected transfer and transfer capacity in EGFIMP 02 boundary – peak demand

The above figures shows that the ECIMP 01 has enough capacity to accommodate between approximately 50 MW and 20 MW over the ten-year study period.

Figure 33 shows that the expected transfer into Eastern Goldfield (EGFIMP 01) import boundary is close to the transfer capacity during the first few years of the study period. This limitation is improved by the additional capacity introduced by the implementation of related TXIP projects.

Export 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 12.

The expected transfer and transfer capacity for each of the export boundaries across the study period are shown in Figure 36 and Figure 37.

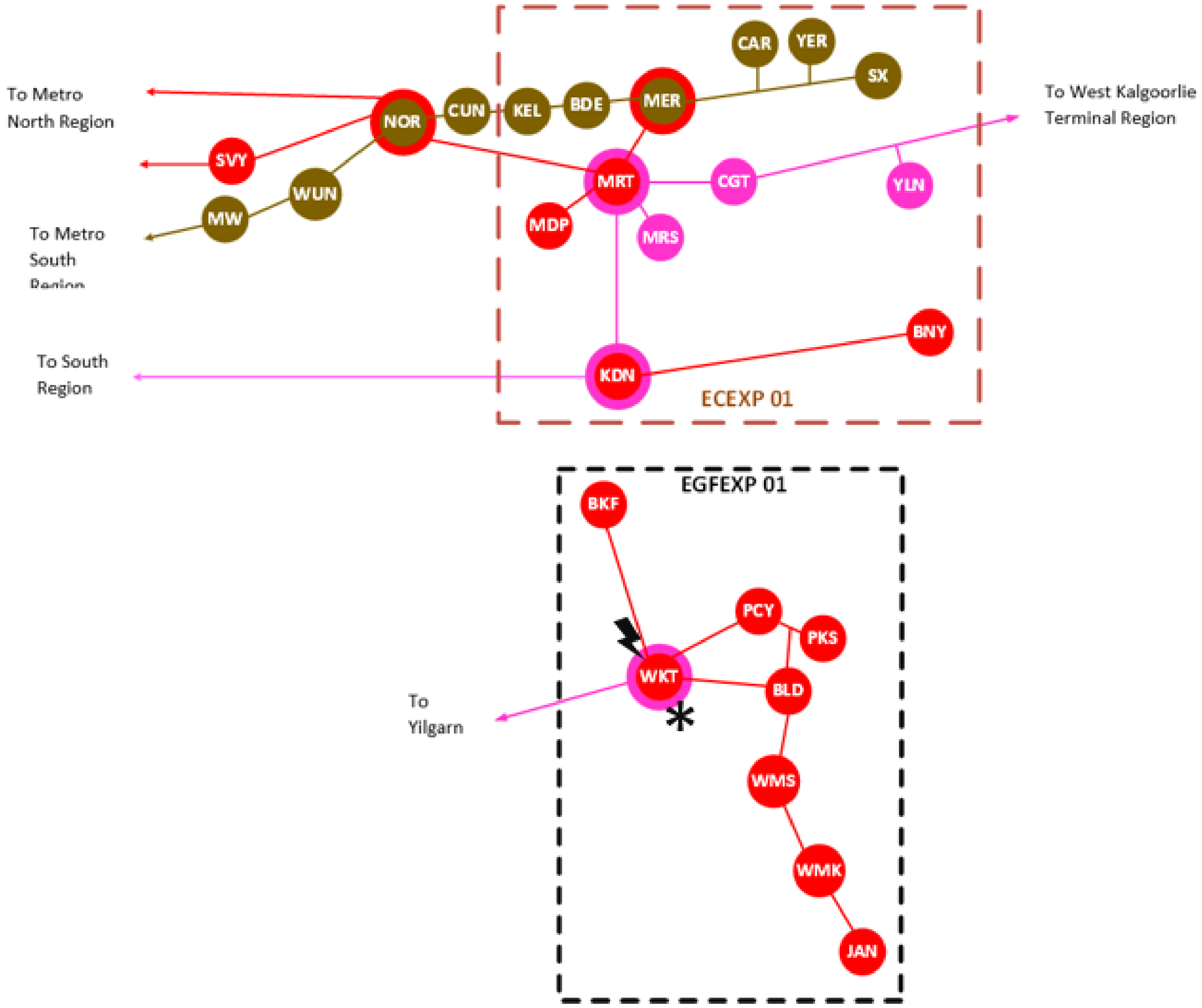

Figure 35: Network import boundaries in the East Region

Table 12: 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

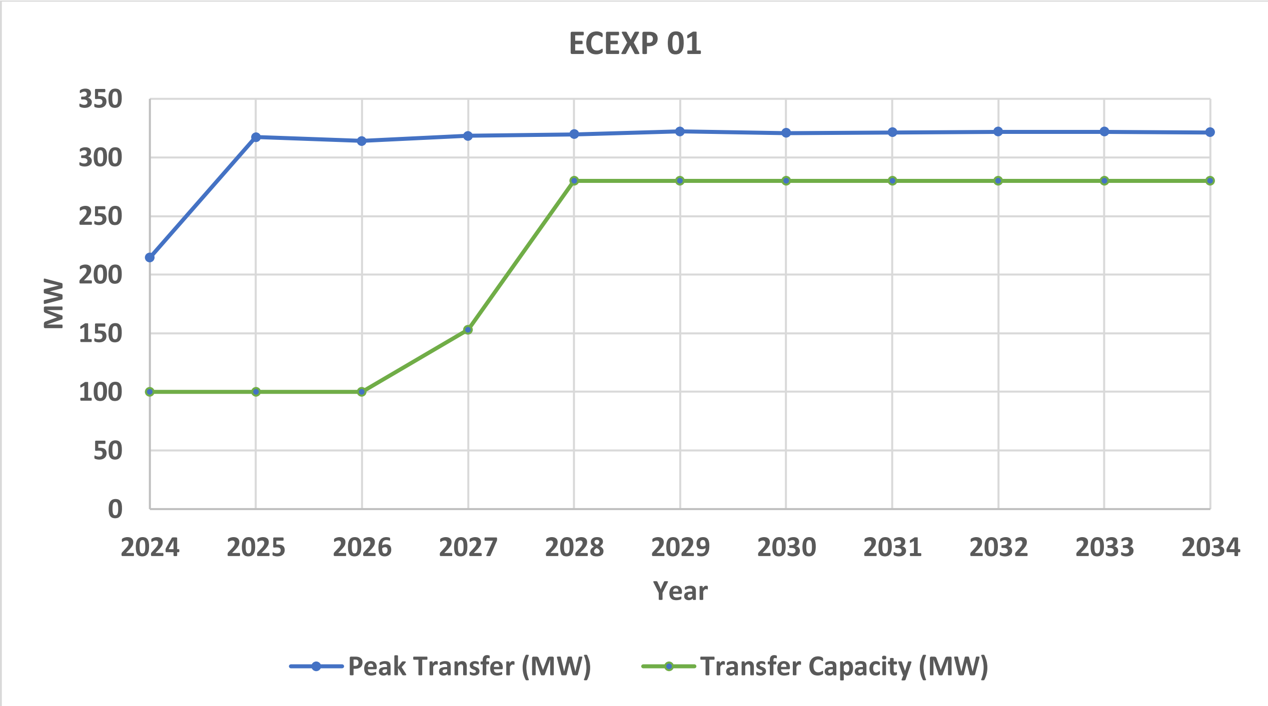

Figure 36: Expected transfer and transfer capacity in ECEXP 01 boundary – peak demand

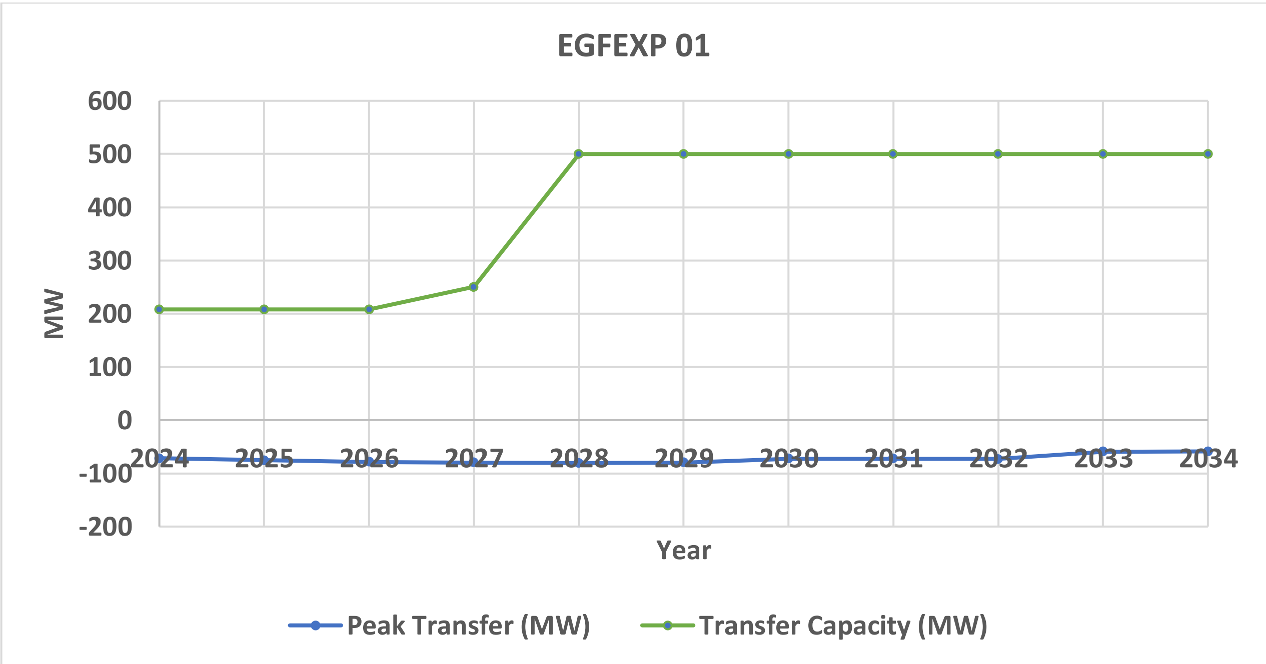

Figure 37: Expected transfer and transfer capacity in EGFEXP 01 boundary – peak demand

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 37.

The above figures illustrate the available import and export capacity within eastern area boundaries for the duration of the study period. TXIP provides for additional capacity, shown by the change in the transfer capacity values, by 2028 (see TXIP description in section 3).

12.3.2 Reliability

Due to its reliance on 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[36].

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. Such improvements in the reliability of electricity supply in the Goldfields Region are being sought by establishing a Non-Co-optimised Essential System Services (NCESS) for up to 150MW of reliability and system strength services for the region. This process is underway and will improve reserve supply, given that the existing NCS scheme has 45 MW capacity.

12.4 Emerging Issues and Drivers

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.

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.

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.

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 augmentations 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.

There are further TXIP transmission investments under development to increase network capacity and these are outlined broadly in section 3.4.

[36] Refer to Technical Rules clause 2.5.2.1 (b), p. 20.

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 38 shows the transmission system in this region.

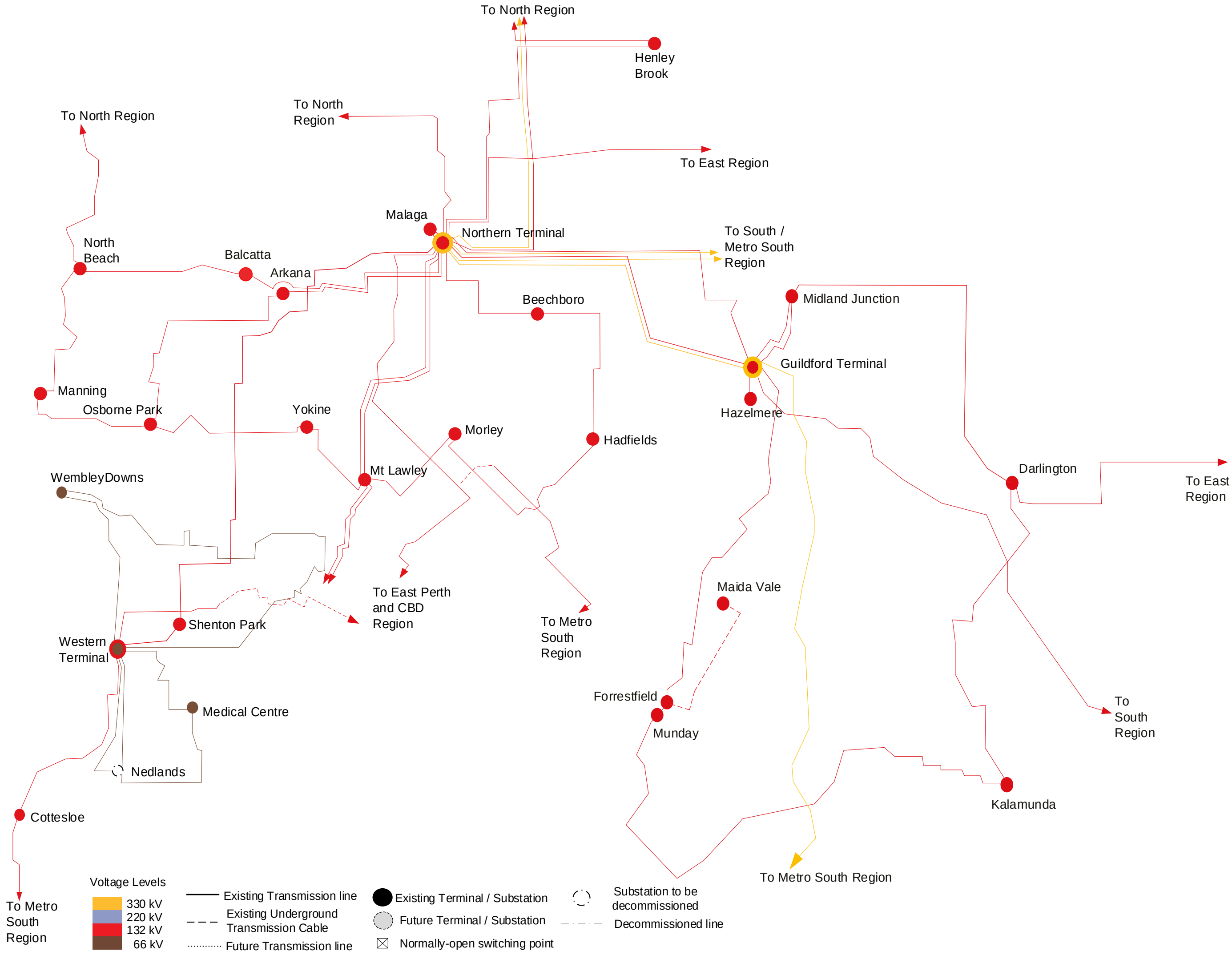

Figure 38: Western Power's Metro North Region – Network Diagram

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 / Western Power 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)
- Munday – 132/22 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

- Maida Vale – 132/25 kV
- Whiteman Park – 132 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 to the 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 ageing 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 discusses 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 39 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 13.

The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 40 to Figure 42.

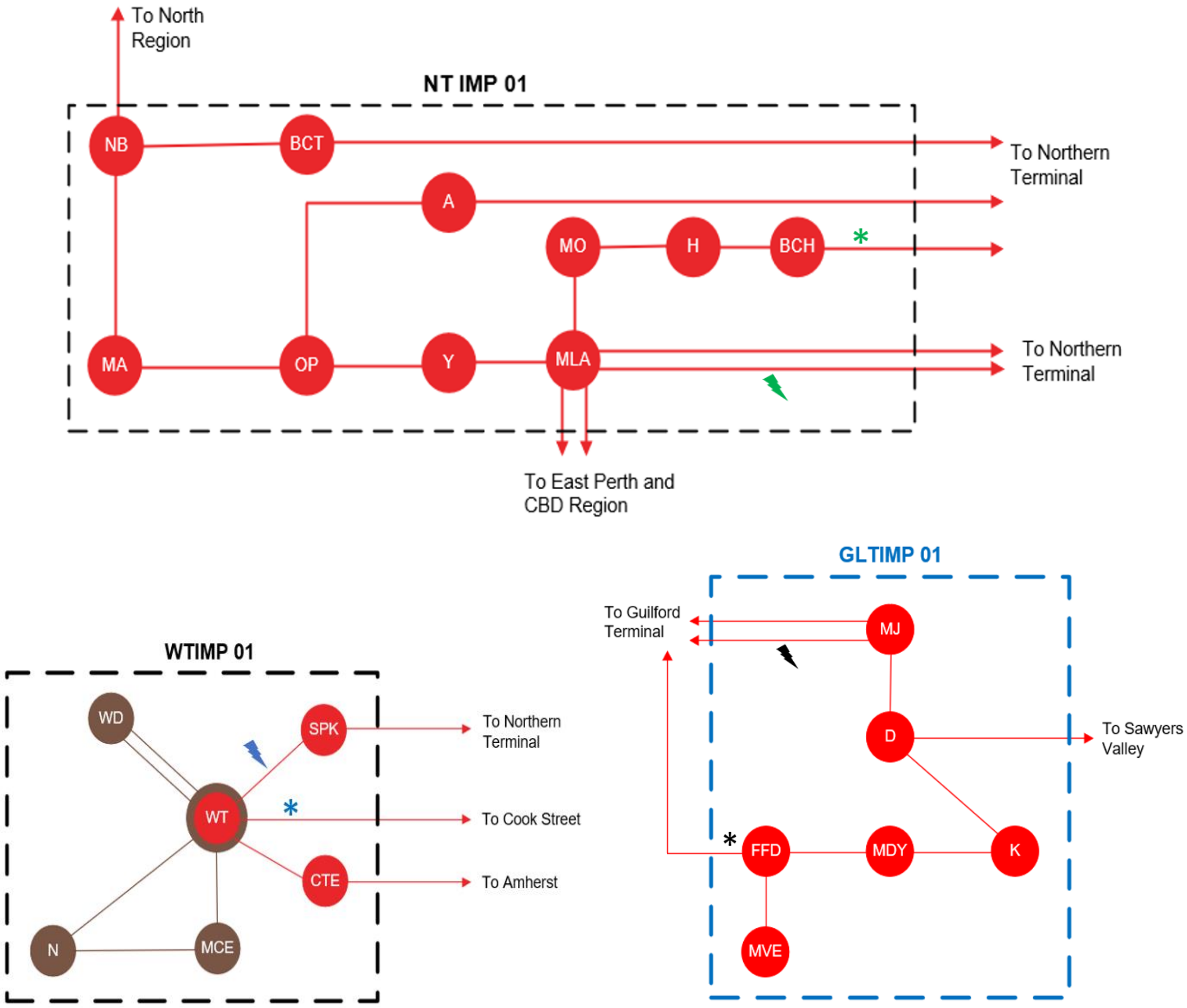

Figure 39: Network import boundaries in the Metro North Region

Table 13: 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 – Midland Junction 81

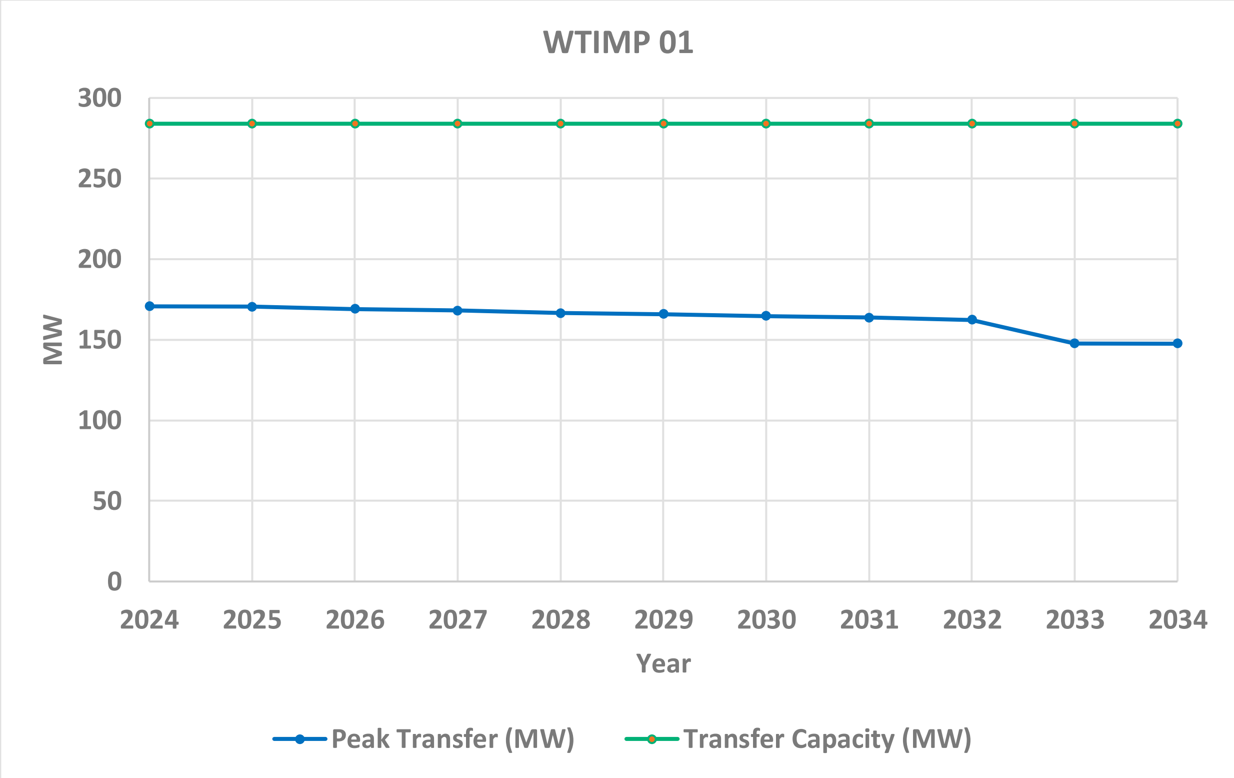

Figure 40: Expected transfer and transfer capacity in WTIMP 01 boundary – peak demand

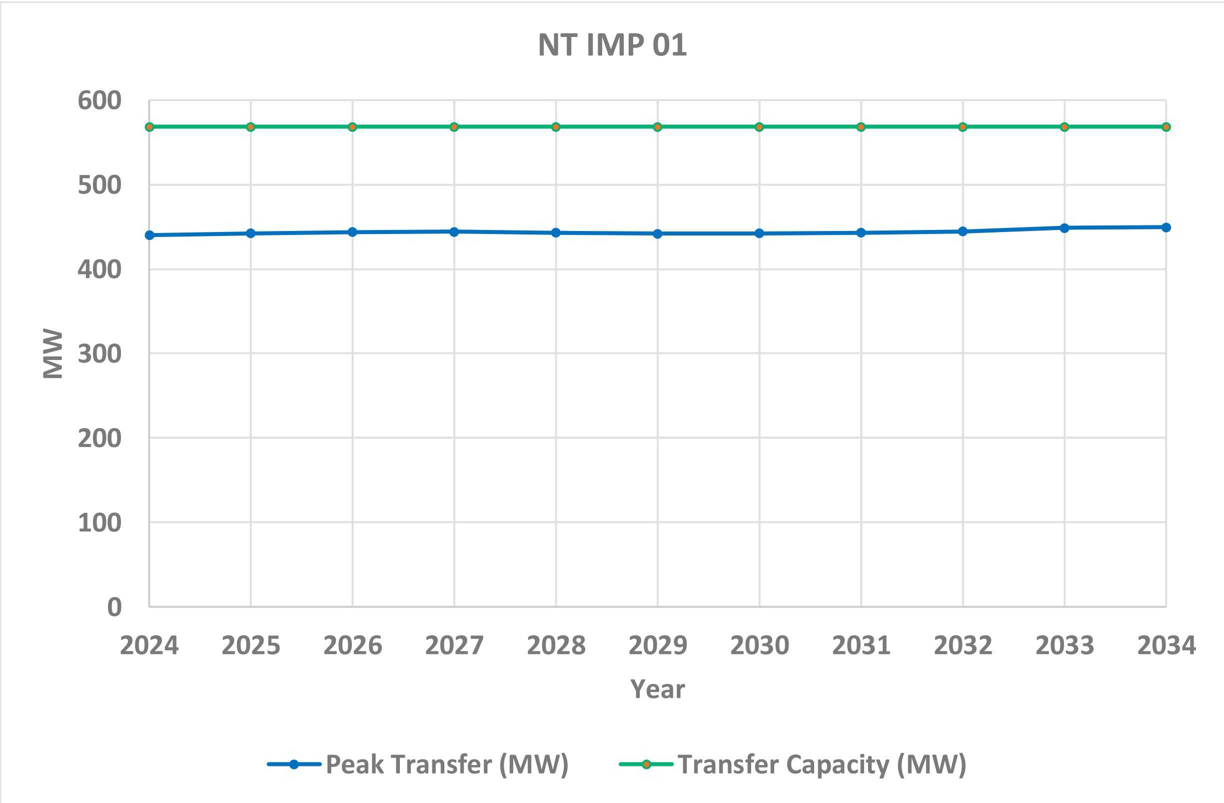

Figure 41: Expected transfer and transfer capacity in NTIMP 01 boundary – peak demand

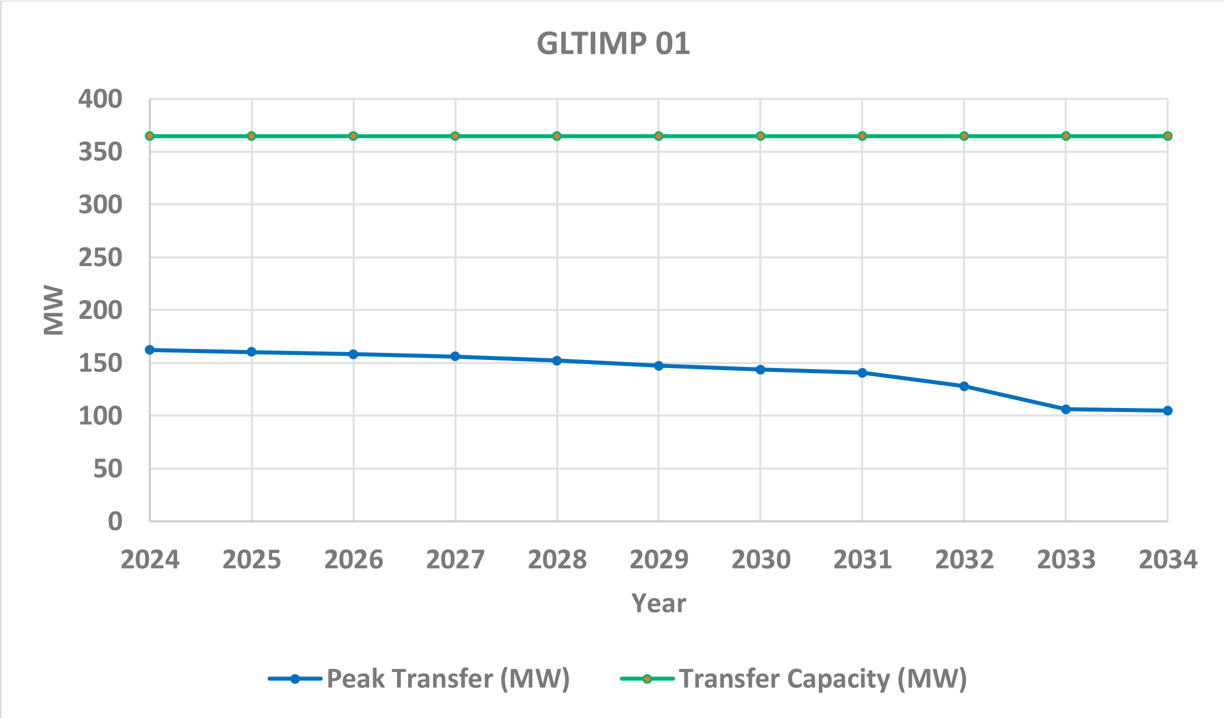

Figure 42: Expected transfer and transfer capacity in GLTIMP 01 boundary – peak demand

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 01 import boundary as expected transfers are close to capacity during 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.

13.4 Emerging Issues and Drivers

The Metro North Region is predominately a load centre. As shown in section 13.3.1, most parts of the region have available spare capacity to connect additional load connections, without triggering the need for network augmentation. It is also noted that efficient opportunities for 66 kV upgrades will be taken when possible.

Although the progressive retirement of coal units at Muja and Collie represents a material 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 and will be considered as part of future TSP's. 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 the 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 43 and Figure 44 for illustration purposes only.

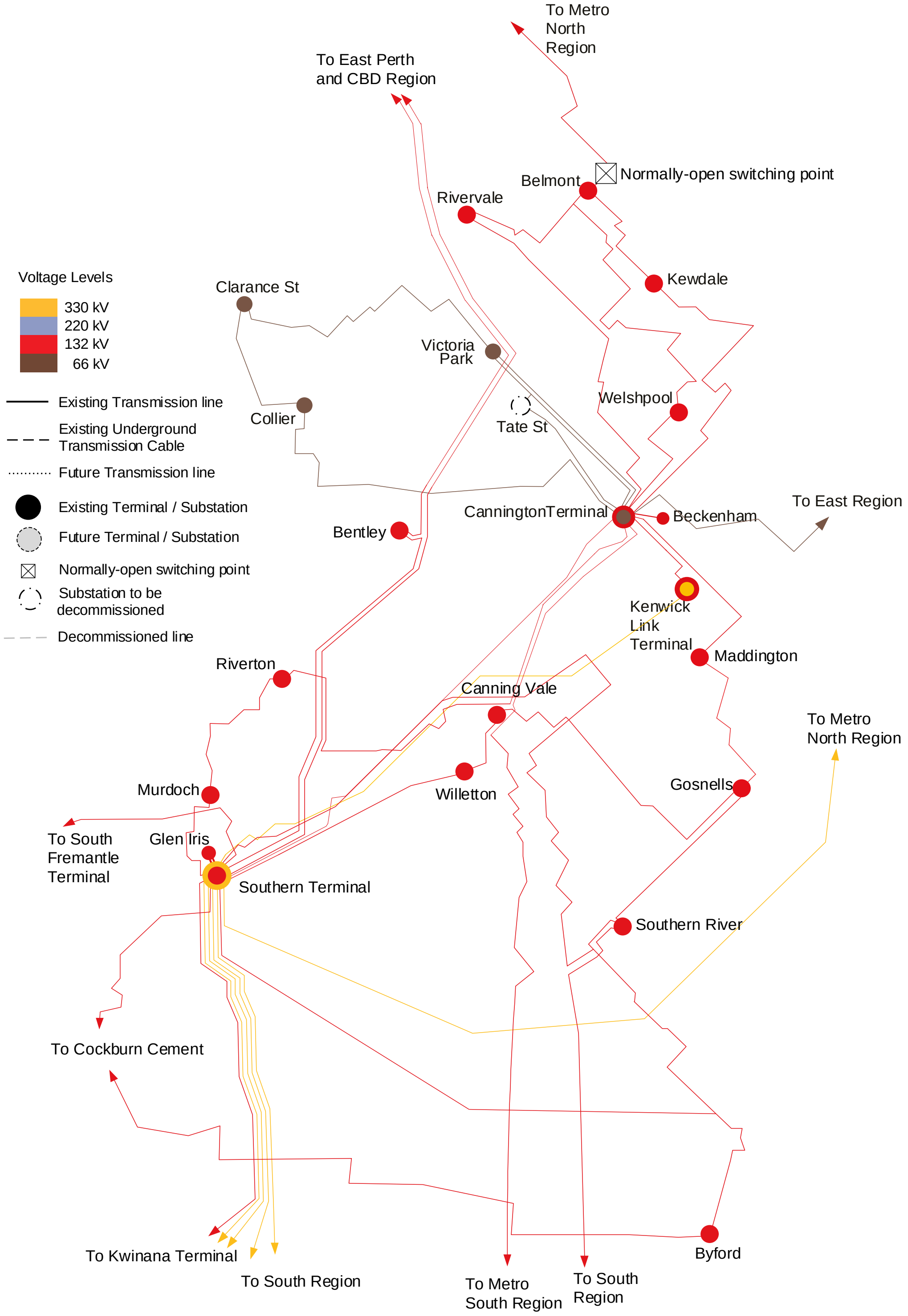

Figure 43: Western Power's Metro South Region (Part A) – Network Diagram

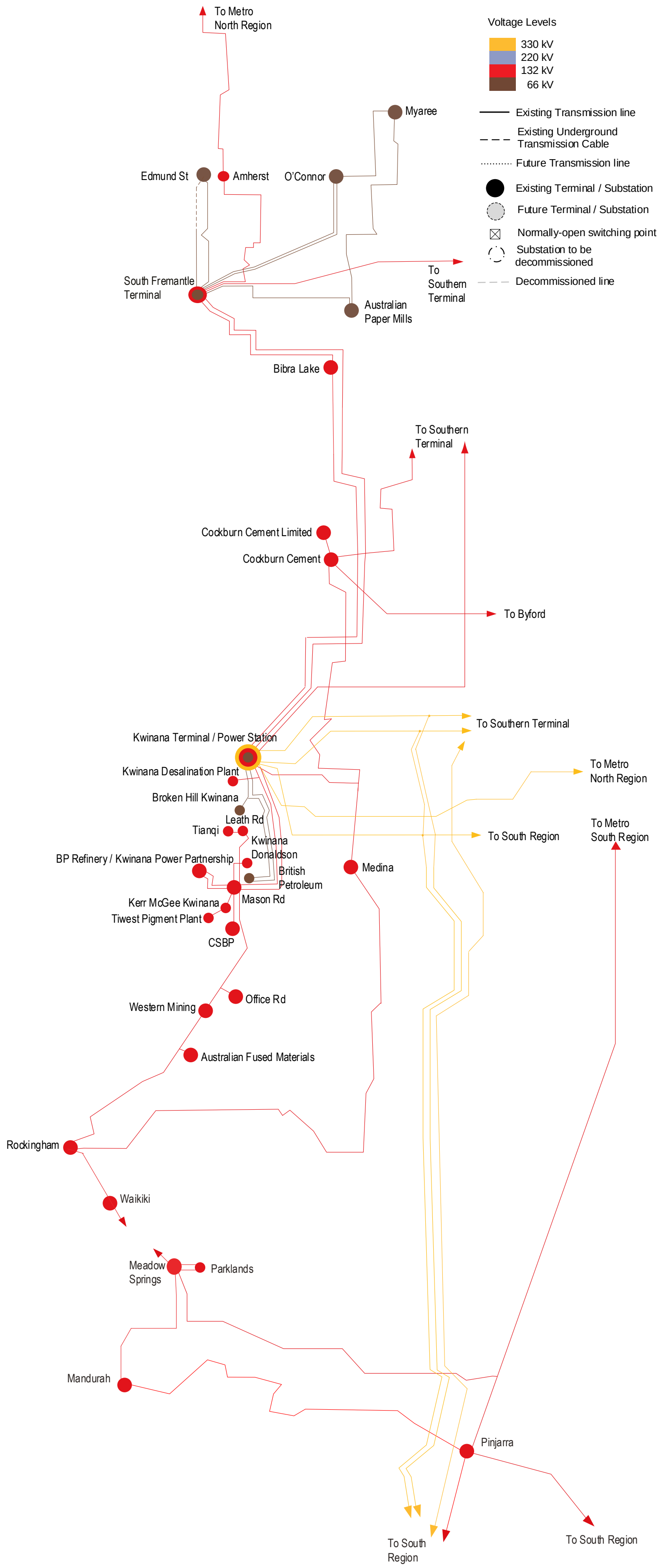

Figure 44: Western Power's Metro South Region (Part B) – Network Diagram

The Metro South Region consists of five terminals – South Fremantle, Kwinana, Southern, Cannington and Kenwick Link - and 31 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 / Western Power 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
- Victoria Park – 66/11 kV[37]
- Waikiki – 132/22 kV
- Welshpool – 132/22 kV
- Willetton – 132/22 kV

Customer substations

- Alcoa Kwinana – 132 kV
- Australian Fused Materials 132 kV
- Beckenham – 132 kV
- British Petroleum – 66 kV
- Broken Hill – 66 kV
- CSBP – 132 kV
- Cockburn Cement Limited – 132 kV
- Cockburn Power Station – 132 kV
- Glen Iris – 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

[37] VP substation is now a 66kV Switchyard

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

Several new developments in the Kwinana area have resulted in two new 132 kV substations, Office Road Substation and Leath Road, which 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 operational (with plans for Stage 2 by 2024/25) 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 45 and Figure 46 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 14.
The expected transfer and transfer capacity for each of the import boundaries across the study period are shown in Figure 47 to Figure 50.

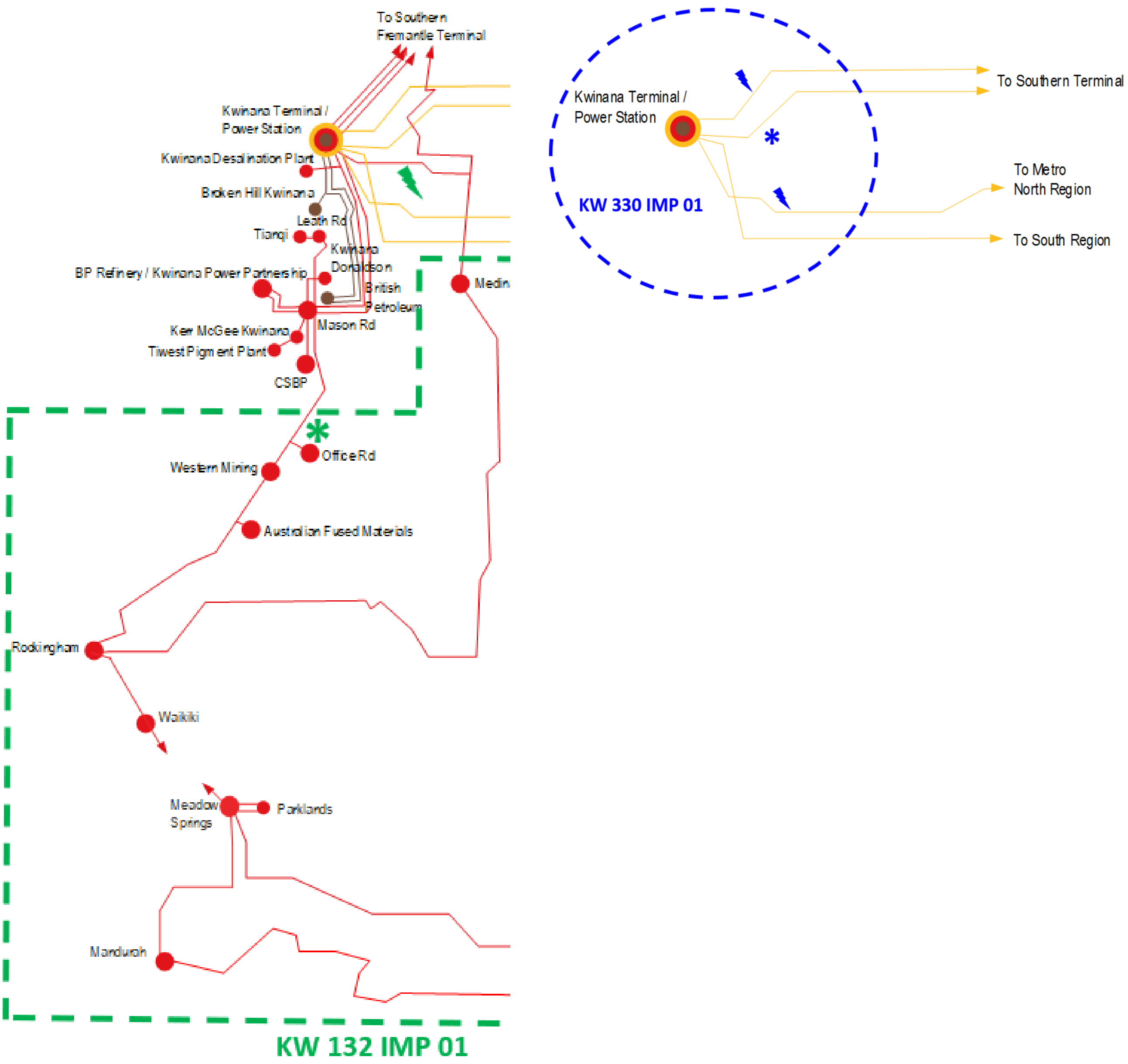

Figure 45: Network import boundaries in the Metro South Region – Kwinana 330 kV and 132 kV

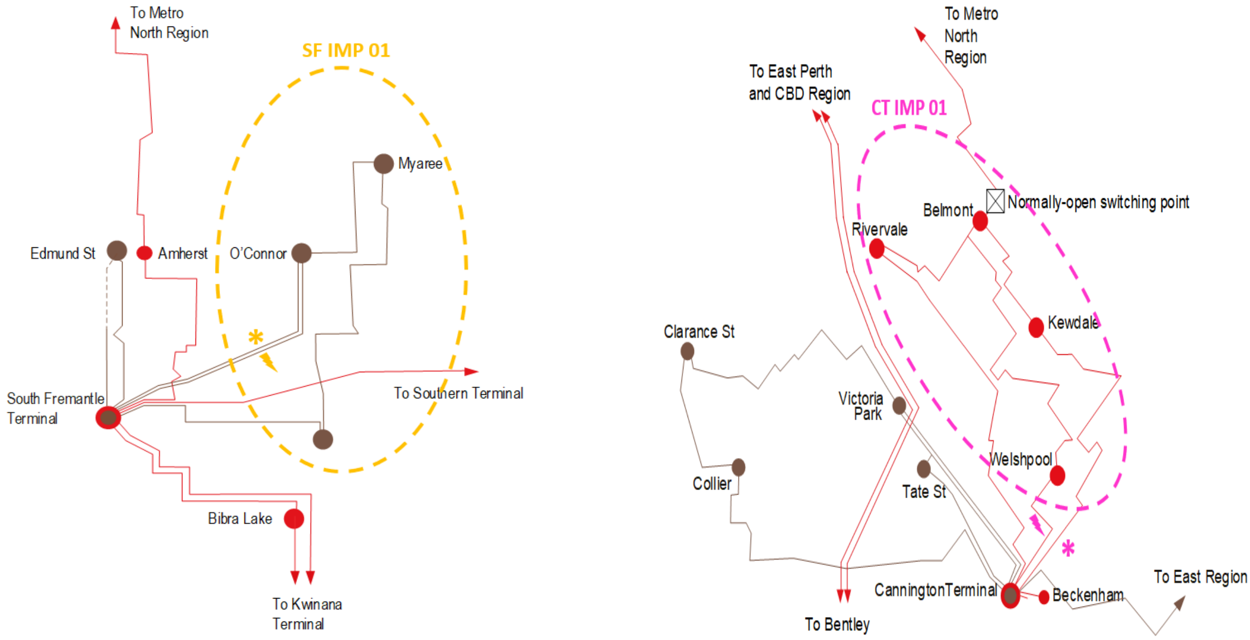

Figure 46: Network import boundaries in the Metro South Region – South Fremantle and Cannington

Table 14: 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	Cannington Terminal - Welshpool 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

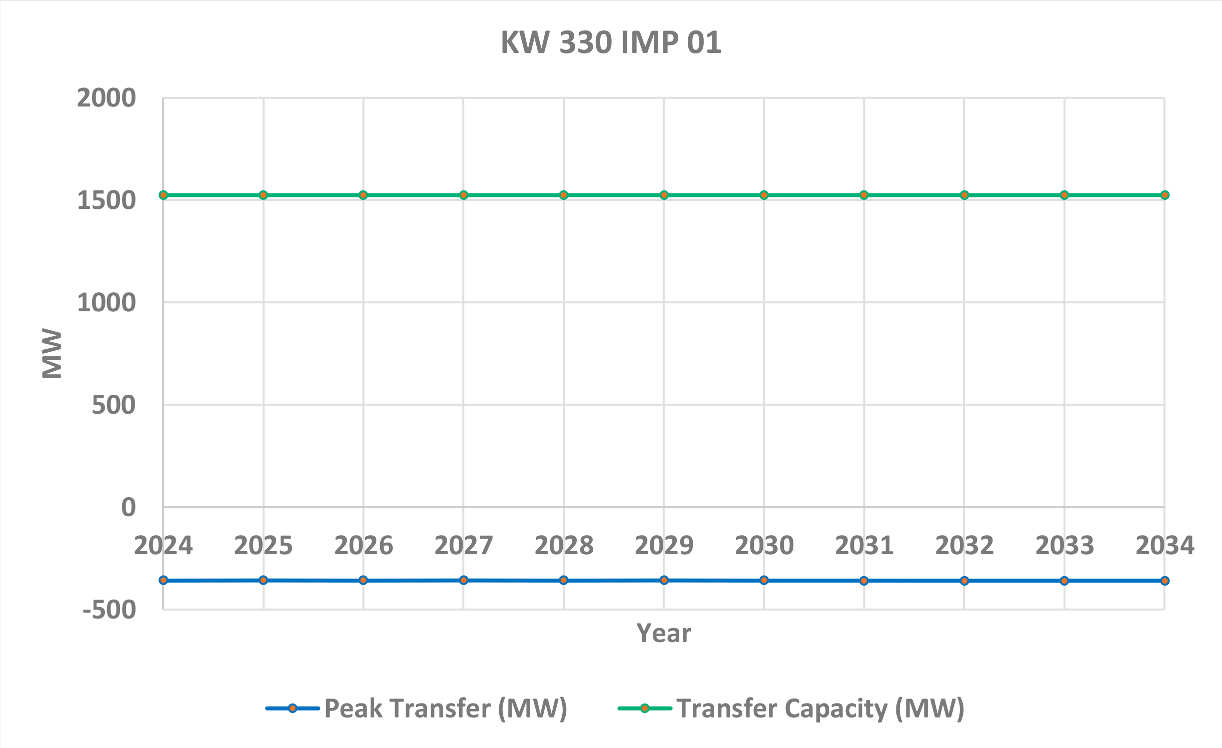

Figure 47: Expected transfer and transfer capacity in KW330IMP 01 boundary – peak demand

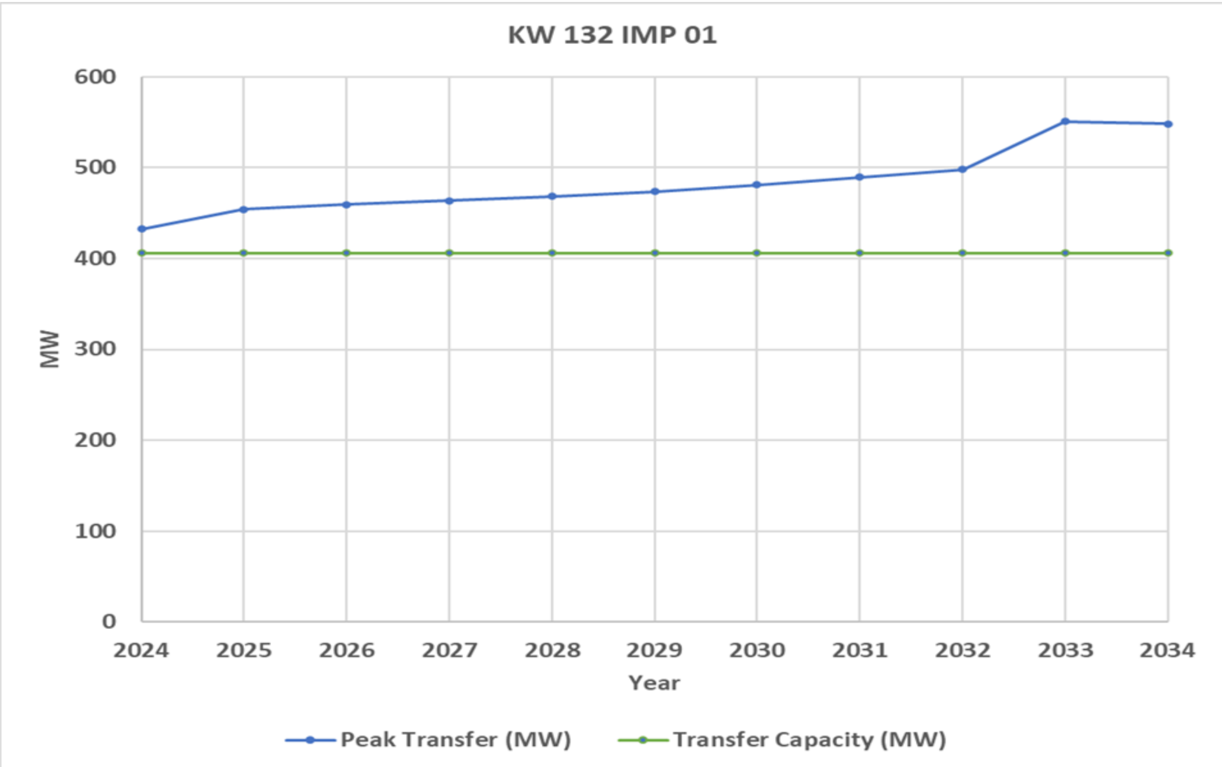

Figure 48: Expected transfer and transfer capacity in KW132IMP 01 boundary – peak demand

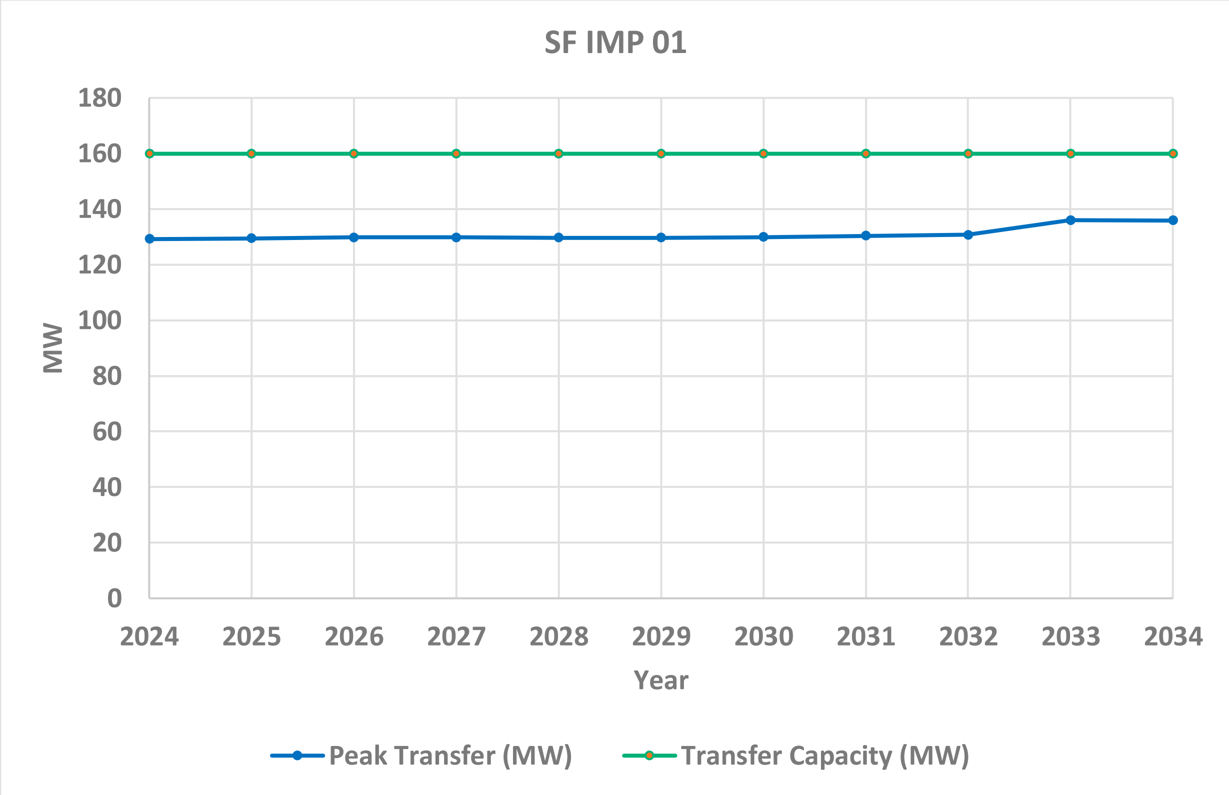

Figure 49: Expected transfer and transfer capacity in SFIMP 01 boundary – peak demand

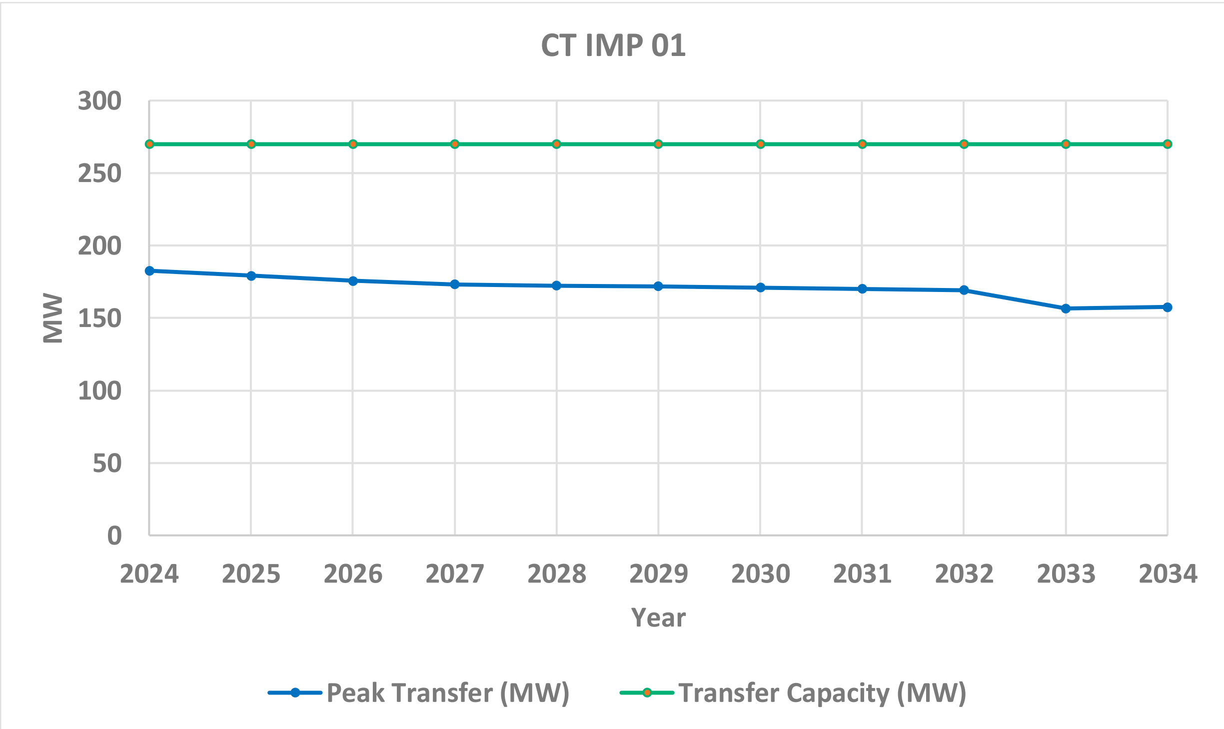

Figure 50: Expected transfer and transfer capacity in CTIMP 01 boundary – peak demand

As shown 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 (per Figure 47), making it a suitable candidate to support large new block load connections at 330kV.

The available capacity in the KW 132 IMP 01 boundary is exceeding capacity as residential loads are expected to grow in the future. New reference load connections likely to require network augmentation works. This area could benefit from alternative solutions to manage peak load periods.

The SFIMP 01 and CTIMP 01 import boundaries have available capacity to accommodate increasing and new load connections.

Export Boundaries

Figure 51 shows the network export boundaries in the Metro South Region. These boundaries are defined using the worst contingency (↯) and the worst overload circuit (*) as shown in Table 15.

The expected transfer and transfer capacity for each of the export boundaries across the study period are shown in Figure 52 to Figure 53.

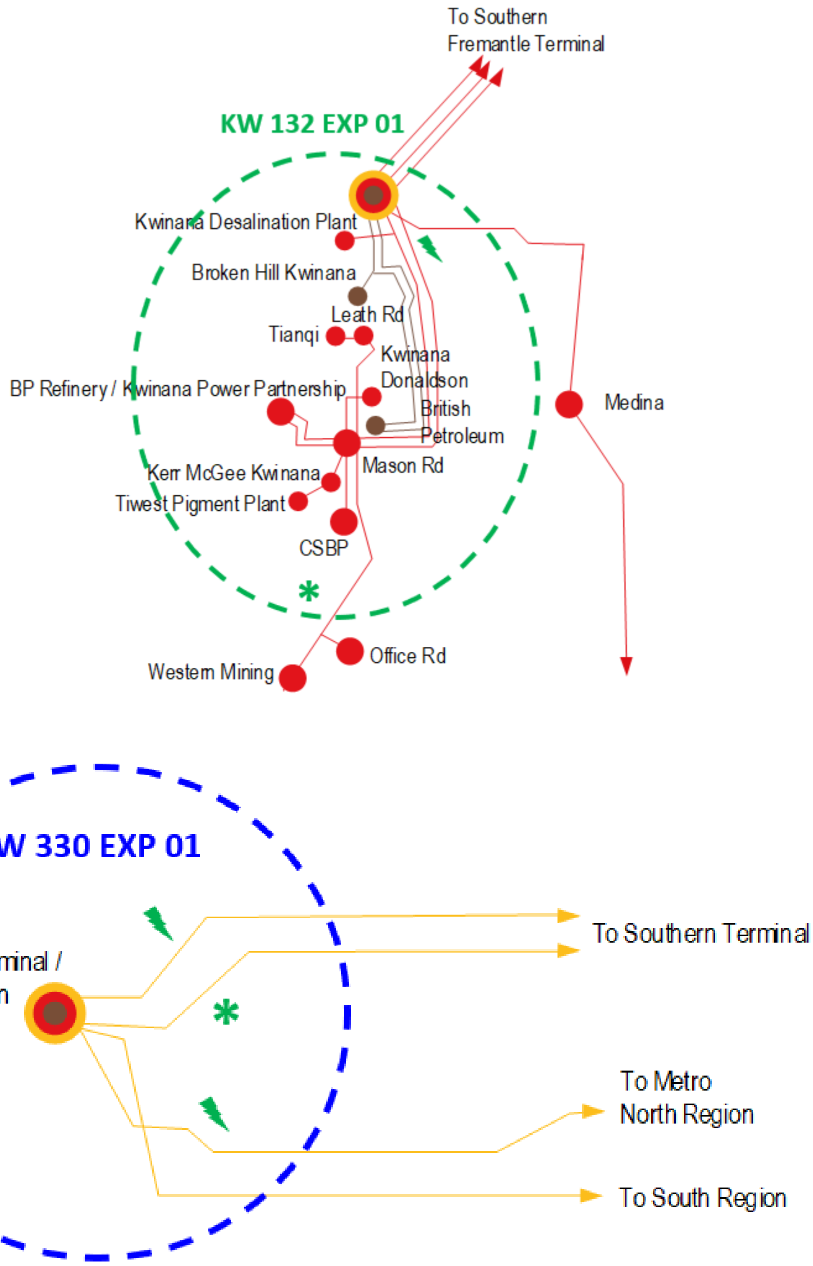

Figure 51: Network export boundaries in the Metro South Region

Table 15: 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

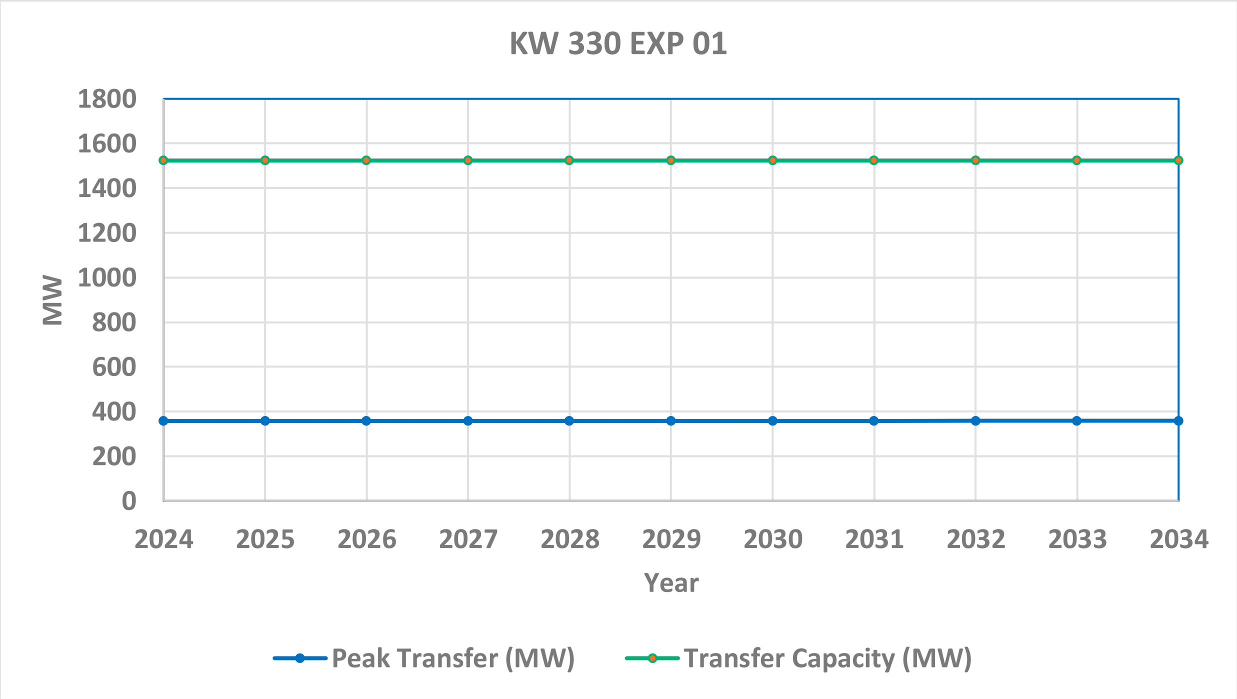

Figure 52: Expected transformer and transfer capacity in KW330EXP 01 boundary – peak demand

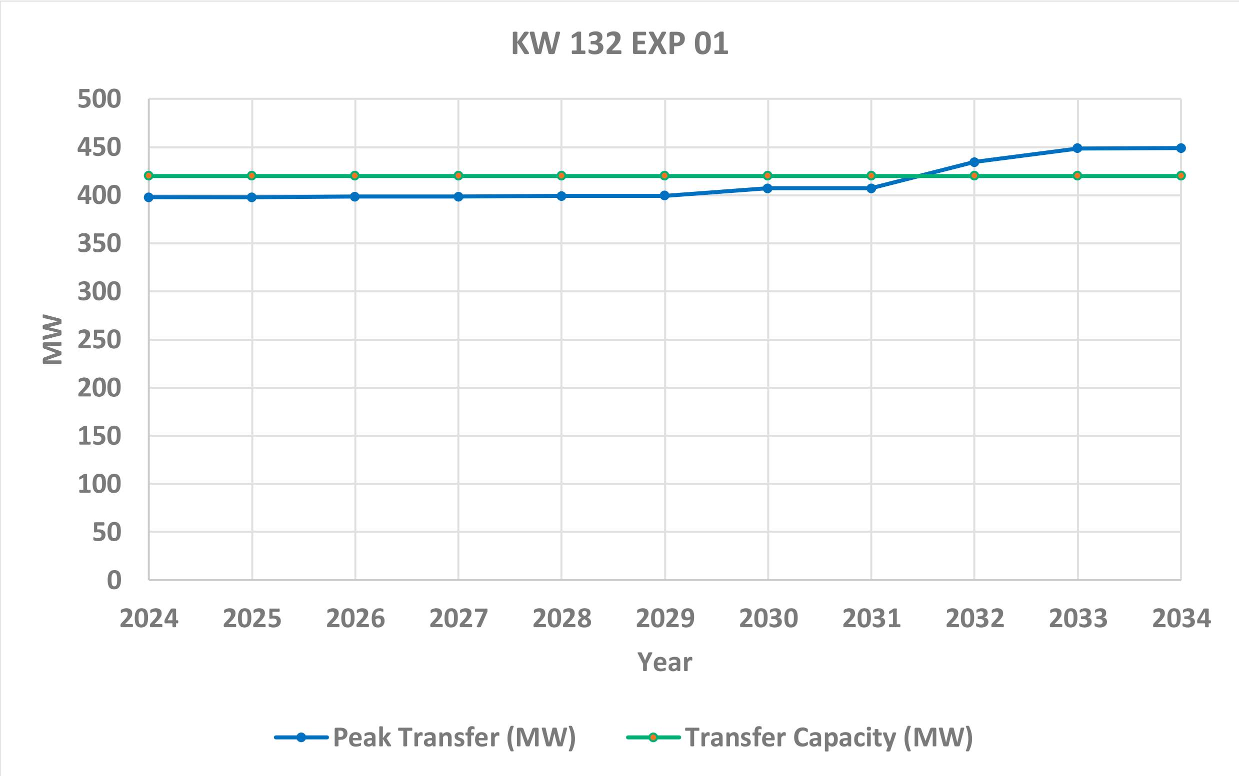

Figure 53: Expected transfer and transfer capacity in KW132EXP 01 boundary – peak demand

Under N-1-1, the KW330EXP 01 export boundary has almost 1200 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 limited available and eventually no capacity over the study period and would require potential network augmentation to facilitate new generation connections

14.4 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 received enquiries regarding the connection of new generators and loads 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 changes 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. The 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 and will be considered as part of future TSP’s. 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 Perth CBD Region covers the Perth Central Business District (CBD), the City of Subiaco and the City of Vincent. Figure 54 shows the transmission system in this region.

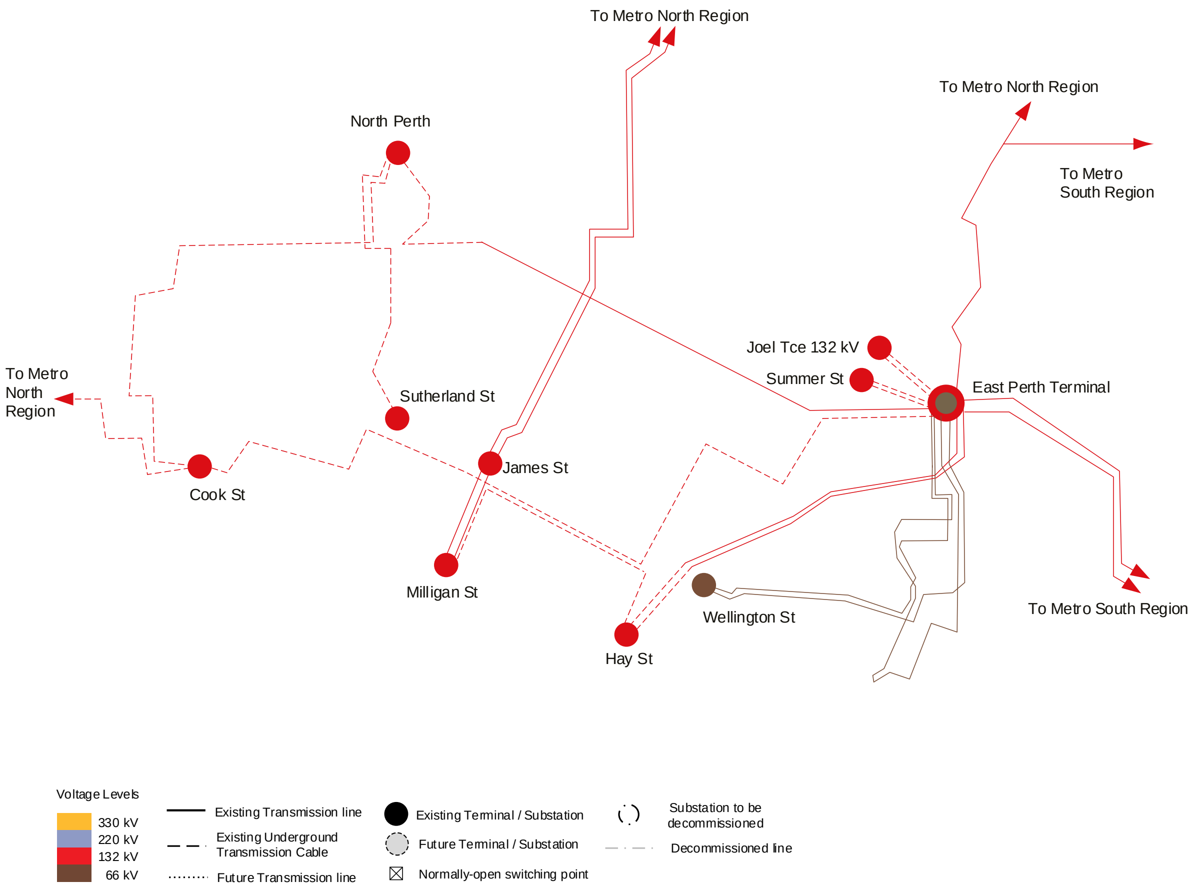

Figure 54: Western Power's East Perth and CBD Region – Network Diagram

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.

Terminals

- East Perth Terminal – 132/66 kV

Zone Substation / Western Power Substations

- Cook Street – 132/11 kV
- Joel Terrace – 132/11 kV[38]
- Hay Street– 132/11 kV
- Milligan Street – 132/11 kV
- North Perth – 132/11 kV
- Wellington Street – 66/11 kV

Customer Substations

- Summer Street (PTA)– 132/11 kV

[38] F has been decommissioned and load transferred to JTE and HAY

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, except for 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 to 10 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 but 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 following the COVID-19 pandemic, with the Perth CBD zone experiencing the greatest level of impact.

In late 2018, the (dis-used) East Perth Power Station and the adjoining land owned by Main Roads commenced redevelopment. As part of those works, Western Power carried out the following works:

a. decommissioning the 66 kV assets East Perth 66 kV Substation

b. undergrounding the 132 kV overhead transmission line in the foreshore area of the site.

As it is neither practical nor economic to retain both 66 kV and the new 132 kV infrastructure, the redevelopment works in the area has triggered decommissioning and reconfiguration of the 66 kV transmission assets – in particular, upgrading Forrest Avenue and Wellington Street substations and their 66 kV supplies.

15.3 Network Performance

This section presents the network performance for the East Perth and CBD Region over the study period. The following assumptions were made in developing the import and export boundaries:

15.3.1 Thermal Capacity – Boundaries

The import boundaries assume that peak demand and security constrained and economic dispatch conditions apply.

Import Boundary

Figure 55 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 16 .

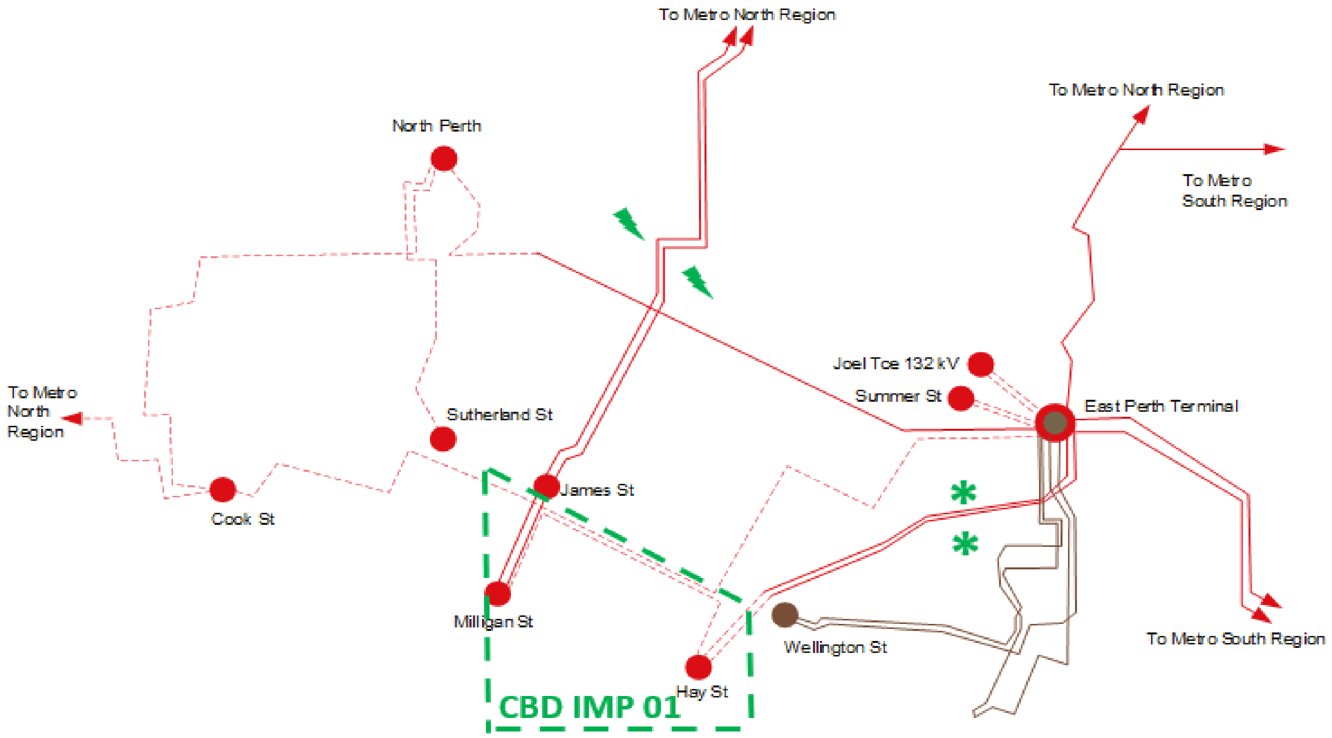

Figure 55: Network import boundaries in the East Perth and CBD Region

Table 16: 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

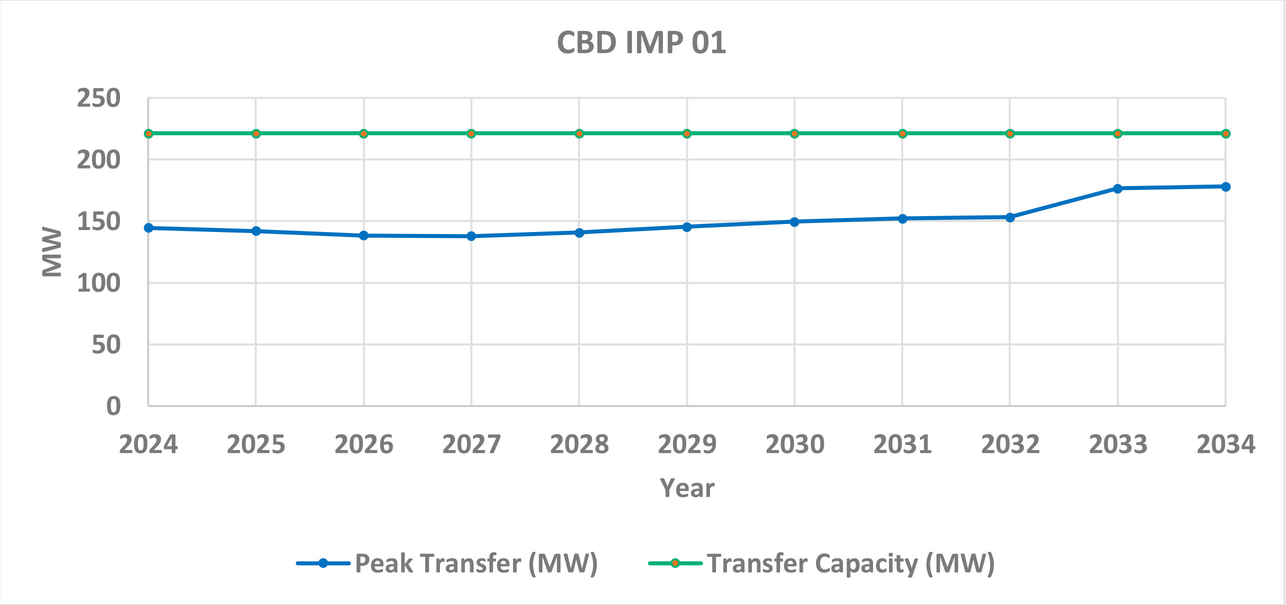

Figure 56: Expected transfer and transfer capacity in CBDIMP 01 boundary – peak demand

As shown in Figure 56, there is limited transfer capacity available into the CBDIMP 01 boundary during system peak demand conditions. The transfer capacity limits into the import boundary are due to sections of underground cable in the East Perth to Hay 81/82 circuits located between the Wellington Street and Hay Street zone substations. Importantly, the cables have lower transfer ratings than the Hay Street zone substation overhead supplies.

It should be noted that the peak transfer and transfer capacity indicated in the above figures change as the network evolves, and Users' or generators demands/behaviour varies.

15.4 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. In addition, both Hay Street and Milligan Street substation buildings are ageing, presenting increasing challenges in maintaining compliance with modern standards, and hence, reliability of supply.

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 potential 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.

Appendix A - Our Operating Environment

Western Power is a State Government owned utility, responsible for building, maintaining, and operating its electricity networks (WPN). It is licenced under the Electricity Industry Act 2004 (Act) and regulated by the Economic Regulation Authority (ERA) which grants and administers the Electricity Transmission Licence (ETL2) and Electricity Distribution Licence (EDL1) held by Western Power. Further, the ERA determines Western Power's revenue, tariffs, services, policies, and incentives via the access arrangement (AA).

Networks operating within the SWIS supports the Wholesale Electricity Market (WEM), which in turn is operated by the Australian Energy Market Operator (AEMO).

Applicable laws and regulations govern all aspects of our operations within the SWIS, from how funding for works is obtained, to standards of supply, and tariff structures. For more information, visit the Energy Policy WA (EPWA) website[39].

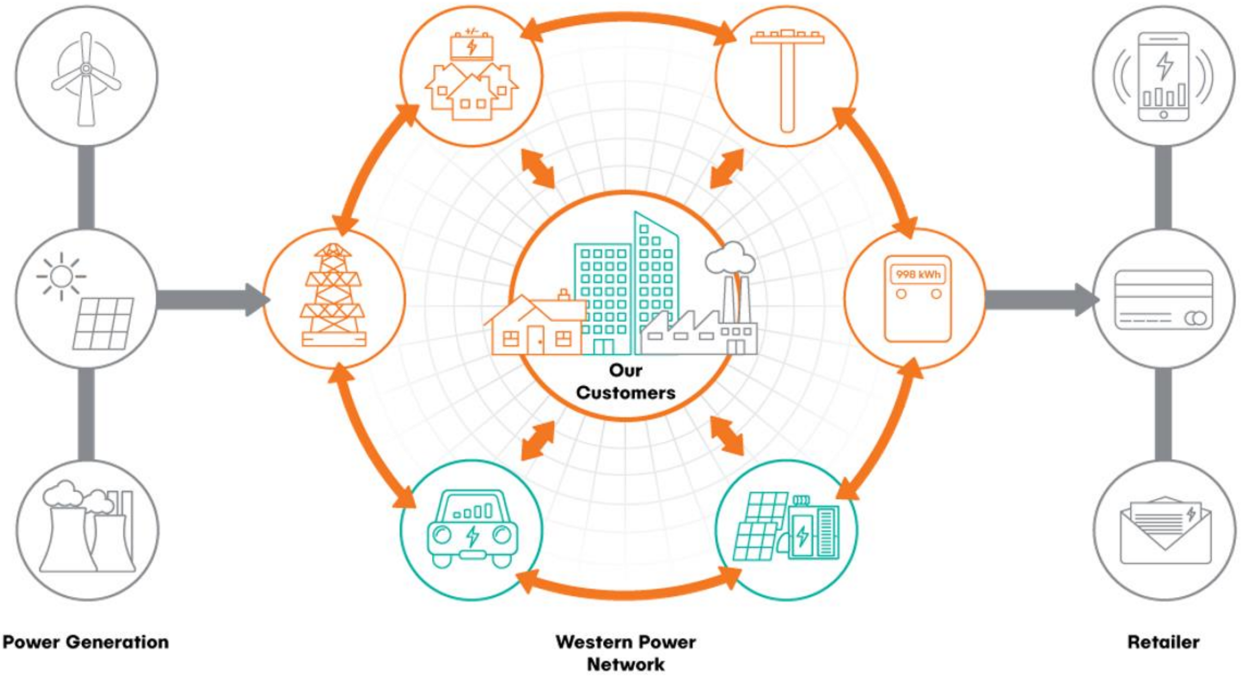

Figure 57: Western Power's role within the Western Australia's electricity market

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

Appendix B - System Study Modelling Data

This section provides linkage to the key modelling inputs for developing the peak and minimum demand scenarios, which holds true from TSP 2023. Whilst TSP 2024 extends the planning horizon by an additional year, the reader is referred to the system study modelling data provided in TSP 2023, Appendix B.

Appendix C - Estimated maximum/minimum short circuit fault levels

Aligning with the requirements under clause 5.5.1 (b) of the Technical Rules, TSP include the 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:

a. 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.
b. 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.
c. Zero fault impedance is assumed.
d. For maximum fault levels, all generation machines and step-up transformers are turned on.
e. All lines are in service.

The reader is reminded:

- of the generic nature of the data;
- there are minor differences in TSP 2024 data compared to the previous TSP 2023 Table;
- shared use is made of NOM data (as a single source, for clarity in referencing); and,
- the need for proposed (new or modified) connections to be assessed to take account of any local network variations, and/or developments, since these studies were completed (in mid-2024).

As such, Network data 2024, "NOM_Network_Data_2024.xlsx" spreadsheet can be accessed via the NOM web page.
Further historical information is also available in the Network data 2023, where that might be helpful.