Appendices

Appendix A Asset management overview

A.1 Introduction

Powerlink's Asset Management System forms part of Powerlink's Business Strategy and is integral to managing and monitoring assets across the asset lifecycle and captures key internal and external drivers and initiatives for the business.

Factors that influence network development, such as energy and demand forecasts, generation development (including asynchronous generation development and potential synchronous generation withdrawal), emerging industry trends and technology, and risks arising from the condition and performance of the existing asset base are analysed collectively to support integrated network planning over a 10-year period.

A.2 Overview of approach to asset management

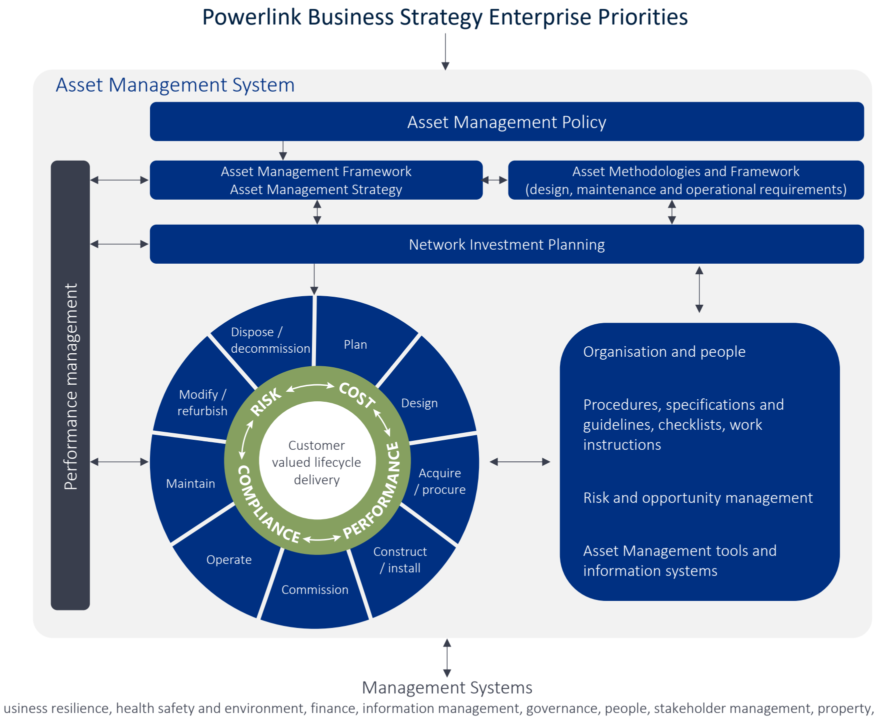
Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver safe, cost effective, reliable and sustainable services.

Asset management is a critical aspect of Powerlink's operations, ensuring efficient management of assets and optimal utilisation of resources. Figure A.1 illustrates the relationships and linkages between the Asset Management Policy, Strategy, and other components of the Asset Management System.

Powerlink's asset management and joint planning approach ensures asset reinvestment needs consider the enduring need and most cost effective options as opposed considering only like-for-like replacements. A detailed analysis of both asset condition and network capability is performed prior to proposed reinvestment and where applicable, a Regulatory Investment Test for Transmission (RIT-T) is undertaken in order to bring about optimised solutions that may involve network reconfiguration, retirement and/or non-network solutions (Refer to sections 6.2 and 6.6).

Powerlink's asset management approach is committed to achieving sustainable practices that ensure Powerlink provides a valued transmission service to meet customers' needs by optimising whole of life cycle costs, benefits and risks and ensuring compliance with applicable legislation, regulations and standards.

Figure A.1 Asset Management Overview



A.3 Powerlink's Asset Management System

Powerlink's Asset Management System ensures assets are managed in a manner consistent with business strategy while supporting and informing other business management systems. Underpinning this system is the Asset Management Policy which sets out the principles to be applied for making asset management decisions as well as ensuring delivery of these decisions. The Asset Management Policy aligns Powerlink's strategic objectives with customer and stakeholder requirements.

The Asset Management Framework and Asset Management Strategy are developed based on Asset Management Policy principles which are used to inform asset management methodologies and activities. The Asset Management Strategy sets the longterm focus for managing assets. Both of these consider the need to continually improve asset management practices.

Powerlink undertake periodic reviews of network assets considering a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and on-going supportability.

Asset Methodologies provide whole of life cycle management for each asset category (transmission lines, substations, digital assets, land assets and underground cables) to inform the delivery of asset life cycle stages.

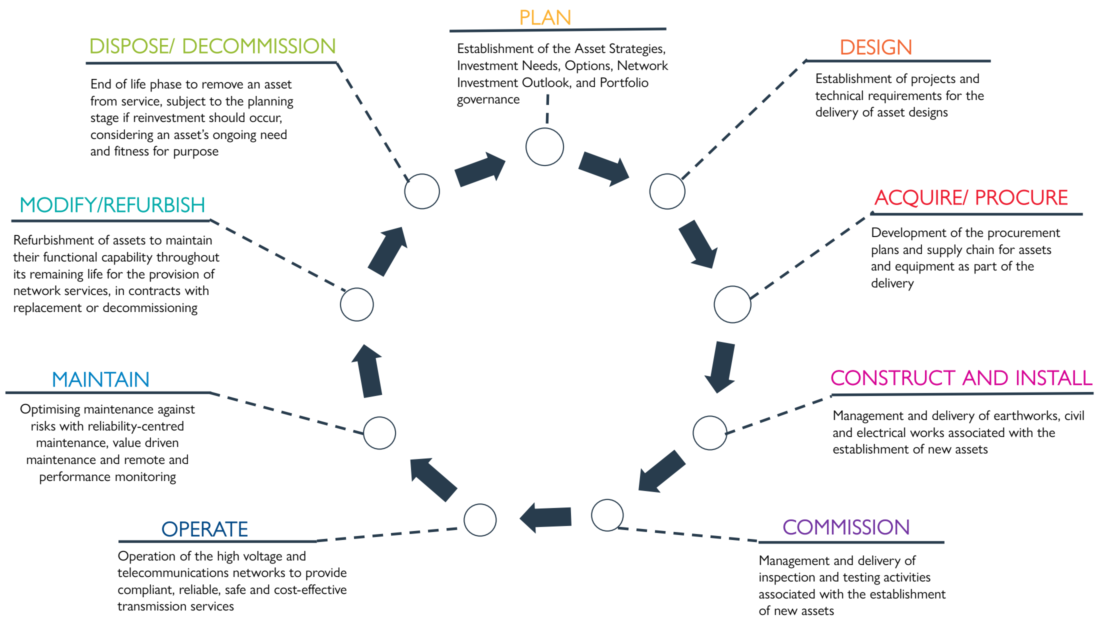
All asset management related activities are undertaken by applying relevant procedures, specifications and guidelines for delivering each stage of an asset life cycle activity.

Asset information is key for Powerlink's asset management with asset data, information and knowledge used to inform a range of asset management and investment decision making processes. Asset information comes from the analysis of asset data which is used to inform decisions on how Powerlink's assets are managed for both short-term operational purposes and longer term strategic plans.

A.3.1 Life cycle delivery

Life cycle delivery establishes how and what is needed for asset decisions and activities in consideration of the Asset Management System. Powerlink defines asset life cycle and main activities throughout the nine stages shown in Figure A.2.

Figure A.2 Powerlink's asset life cycle stages



A.4 Flexible and integrated network investment planning

A fundamental element of the Asset Management System involves processes to manage the life cycle of assets, from planning and investment to operation, maintenance and refurbishment, and end of technical service life.

A range of options are considered as part of a flexible and integrated approach to network investment planning. These options may include retiring or decommissioning assets where there is unlikely to be an on-going future need, refurbishing to maintain the service life of assets, replacing assets with different capacity or type to match needs, alternate network configuration opportunities, and non-network solutions.

The purpose of Powerlink's network investment planning is to:

- apply the principles set out in Powerlink's Asset Management Policy, Framework, Strategy and related processes to guide network asset planning and reinvestment decisions
- provide an overview of asset condition and health, life cycle plans and emerging risks related to factors such as safety, network reliability, resilience and obsolescence
- provide an overview and analysis of factors that impact network development, including energy and demand forecasts, generation developments, forecast network performance and capability, and the condition and performance of Powerlink's existing asset base
- identify potential opportunities for optimisation of the transmission network
- provide the platform to enable the transformation to a more sustainable, cost efficient and climate resilient power system.

A.5 Asset management implementation

Powerlink has adopted implementation strategies across its portfolio of projects and maintenance activities aimed at efficiently delivering the overall work program, including prudent design standardisation by considering emerging trends in technology, portfolio management and supply chain management.

One of Powerlink's objectives includes the efficient implementation of work associated with network operation, field maintenance and project delivery. Powerlink continues to pursue innovative work techniques that:

- reduce risk to personal safety
- optimise maintenance and/or operating costs
- reduce the requirement for and minimise the impacts of planned outages on the transmission network.

In line with good practice, Powerlink also undertakes regular auditing of work performed to facilitate the continuous improvement of the overall Asset Management System.

A.6 Further information

Further information on Powerlink's Asset Management System may be obtained by emailing NetworkAssessments@powerlink.com.au.

Appendix B Joint planning

B.1 Introduction

The objective of joint planning is to collaboratively identify network and non-network solutions to limitations which best serve the long-term interests of customers, irrespective of the asset boundaries (including those between jurisdictions).

Powerlink's joint planning framework with Australian Energy Market Operator (AEMO) and other Network Service Providers (NSP) is in accordance with the requirements set out in Clause 5.14.3 and 5.14.4 of National Electricity Rules (NER). The joint planning process results in integrated area and inter-regional strategies which optimise asset investment needs and decisions consistent with whole of life asset planning.

Joint planning begins several years in advance of an investment decision. Depending upon the nature of the limitation or asset condition driver to be addressed and the complexity of the proposed corrective action, the nature and timing of future investment needs are reviewed at least on an annual basis utilising an interactive joint planning approach.

In general, joint planning seeks to:

- understand the issues faced by the different network owners and operators
- understand existing and forecast network limitations between neighbouring NSPs
- help identify the most efficient options to address these issues, irrespective of the asset boundaries (including those between jurisdictions)
- influence how networks are operated and managed, and what network changes are required.

Projects where a feasible network option exists which is greater than $7 million are subject to a formal consultation process under the applicable regulatory investment test mechanism. The owner of the asset where the limitation emerges will determine whether a Regulatory Investment Test for Transmission (RIT-T) or Regulatory Investment Test for Distribution (RIT-D) is used to progress the investment recommendation under the joint planning framework. This provides customers, stakeholders and interested parties the opportunity to provide feedback and discuss alternative solutions to address network needs. Ultimately, this process results in investment decisions which are prudent, transparent and aligned with stakeholder expectations.

B.2 Working and regular engagement groups

Powerlink regularly undertakes joint planning meetings with AEMO, Energy Queensland and Jurisdictional Planning Bodies (JPB) from across the National Electricity Market (NEM). There are a number of working groups and reference groups which Powerlink contributes to:

- Executive Joint Planning Committee (EJPC)
- Joint Planning Committee (JPC)
- Regulatory Working Group (RWG)
- Forecasting Reference Group (FRG)
- Power System Modelling Reference Group (PSMRG)
- NEM Working Groups of the Energy Networks Australia (ENA)
- 2022 General Power System Risk Review (GPSRR) (refer to Section 7.3)
- AEMO's System Security Reports
- Network Support and Control Ancillary Service (NSCAS)
- System Strength and Inertia requirements
- AEMO's Integrated System Plan (ISP) including joint planning and submissions to the ISP Inputs, Assumptions and Scenarios, ISP Methodology and development of ISP Preparatory Activity reports
- AEMO's System Strength Impact Assessment Guidelines and Methodology
- AEMO and jurisdictional planners to support and promote collaboration and coordination of model development, model management and test activities to facilitate the safe and expeditious release of inter-network capacity

- Transgrid when assessing the economic benefits of expanding the power transfer capability between Queensland and NSW
- Energex and Ergon Energy (as part of the Energy Queensland Group) for the purposes of efficiently planning developments and project delivery in the transmission and sub-transmission network.

B.2.1 Executive Joint Planning Committee

The EJPC coordinates effective collaboration and consultation between JPBs and AEMO on electricity transmission network planning issues. The EJPC directs and coordinates the activities of the Forecasting Reference Group, and the Regulatory Working Group. These activities ensure effective consultation and coordination between JPB, Transmission System Operators and AEMO on a broad spectrum of perspectives on network planning, forecasting, market modelling, and market regulatory matters in order to deal with the challenges of a rapidly changing energy industry.

B.2.2 Joint Planning Committee

The JPC is a working committee supporting the EJPC in achieving effective collaboration, consultation and coordination between JPB, Transmission System Operators and AEMO on electricity transmission network planning issues.

B.2.3 Forecasting Reference Group

The FRG is a monthly forum with AEMO and industry forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

B.2.4 Regulatory Reference Group

The RWG is a working group to support the EJPC in achieving effective collaboration, consultation and coordination between JPBs, Transmission System Operators and AEMO on key areas related to the application of the regulatory transmission framework and suggestions for improvement.

B.2.5 Power System Modelling Reference Group

The PSMRG is a technical expert reference group which focuses on power system modelling and analysis techniques to ensure an accurate power system model is maintained for power system planning and operational analysis, establishing procedures and methodologies for power system analysis, plant commissioning and model validation.

B.3 AEMO Integrated System Plan

Powerlink works closely with AEMO to support the development of the ISP. The ISP sets out a roadmap for the eastern seaboard's power system over the next two decades by establishing a whole of system plan for efficient development that achieves system needs through a period of transformational change.

During 2023 and 2024 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. Powerlink and the Department of Energy and Climate (DEC) have provided advice to AEMO on the status of projects, transmission and Pumped Energy Hydro Scheme (PHES) projects, defined in the Queensland Energy and Jobs Plan (QEJP) for inclusion in their ISP modelling. This resulted in the Borumba PHES and CopperString 2032 projects being modelled as anticipated projects in the 2024 ISP.

Process

Powerlink continues to provide a range of network planning inputs to AEMO's ISP consultation and modelling processes, via joint planning processes, regular engagement, workshops and various formal consultations.

Methodology

More information on the 2026 ISP including methodology and assumptions is available on AEMO's website.

Outcomes

The ISP attempts to identify a long-term plan for the efficient development of the NEM transmission network, and the connection of Renewable Energy Zones (REZ) over the coming 20 years. It is based on a set of assumptions and a range of scenarios.

B.4 AEMO national planning – System strength, inertia and NSCAS reports

AEMO has identified system security needs across the NEM for the coming five-year period as the energy transformation continues at pace. Declining minimum operational demand, changing synchronous generator behaviour and rapid uptake of variable renewable energy (VRE) resources combine to present opportunities for delivery of innovative and essential power system security services. The 2023 System Security Report is part of the NER framework intended to plan for the security of the power system under these changing operating conditions.

Process

Powerlink has worked closely with AEMO to determine the system strength, inertia and NSCAS requirements for the Queensland region. Powerlink and AEMO reviewed the Queensland fault level nodes and their minimum three phase fault levels and assessed the reactive power absorption requirements.

Methodology

AEMO applied the System Strength Requirements Methodology[1] to determine the Queensland fault level nodes and their minimum three phase fault levels. More information on the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls is available on AEMO's website.

AEMO applied the Network Support and Control Ancillary Service Description and Quantity Procedure[2] to identify whether there are reactive power capability gaps.

Outcomes

The 2023 System Security Report confirmed the existing minimum fault level requirements in Queensland and the system strength shortfall at the Gin Gin node. Powerlink commenced an Expression of Interest (EOI) process for short and long-term non-network solutions to the fault level shortfall at the Gin Gin node and expect to publish the response to the shortfall by December 2023 (refer to Section 6.8.1).

The 2023 System Security Report published the minimum fault level requirement at each system strength node and AEMO's forecast level and type of inverter-based resources (IBR) and market network service facilities over a 10-year period. Powerlink, as Queensland System Strength Service Provider, (SSSP), needs to procure system strength services to meet these requirements. In March 2023 Powerlink commenced a RIT-T to identify a portfolio of solutions to meet these minimum and efficient levels of system strength. Powerlink has been working with proponents of non-network solutions to inform the technical and economic analysis for the optimal portfolio of solutions anticipated to be required. Powerlink will publish the Project Assessment Draft Report (PADR) in November 2024, which will identify the proposed preferred option to provide minimum and efficient levels of system strength (refer to Section 6.8.2).

B.5 General Power System Risk Review and Power System Frequency Risk Review

AEMO published the 2024 General Power System Risk Review (GPSRR) in July 2024.

Process

In accordance with rule 5.20A of the NER, AEMO in consultation with TNSPs prepares a GPSRR for the NEM. The purpose of the GPSRR is to review:

- a prioritised set of risks comprising contingency events and other events and conditions that could lead to cascading outages or major supply disruptions
- the current arrangements for managing the identified priority risks and options for their future management
- the arrangements for management of existing protected events and consideration of any changes or revocation
- the performance of existing Emergency Frequency Control Schemes (EFCS) and the need for any modifications.

1 System Security Market Frameworks Review.
System Strength Requirements Methodology - September 2022 (latest version).
2 Network Support and Control Ancillary Service Description and Quantity Procedure.

Methodology

With support from Powerlink, AEMO assessed the performance of existing EFCS. AEMO also assessed high priority non-credible contingency events identified in consultation with Powerlink. From these assessments AEMO determines whether further action may be justified to manage frequency risks.

Outcomes

The Final 2024 GPSRR report recommended:

- Powerlink and Transgrid investigate, design and implement a special protection scheme (SPS) to mitigate the risk of Queensland New South Wales Interconnector (QNI) instability and synchronous separation of Queensland following a range of non-credible contingencies
- Jurisdictions develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risk
- Powerlink and Energy Queensland to identify and implement measures to restore under frequency load shedding (UFLS) load, and to collaborate with AEMO on the design and implementation of remediation measures.
- NSPs manage risks associated with localised aggregated Battery Energy Storage System (BESS) response to remote frequency disturbances
- AEMO finalise the development of an updated strategy for the overall co-ordination of generator over frequency protection settings.

Carry-over recommendations from the 2022 Power System Frequency Risk Review and 2023 General Power System Risk Review include:

- NSPs evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training
- Implementation of a SPS for the loss of both Columboola to Western Downs 275kV lines. The loss of both of these lines, which supply the Surat zone, is non-credible but could cause QNI to lose stability
- Assessment of the risk and solution options to further mitigate instability for the non-credible loss of both Calvale to Halys 275kV lines following the QNI minor commissioning.

B.6 Joint planning with Transgrid – Expanding the transmission transfer capacity between New South Wales and Queensland

In December 2019, Powerlink and Transgrid finalised a Project Assessment Conclusions Report (PACR) on 'Expanding NSW-Queensland transmission transfer capacity'. The recommended option includes uprating the 330kV Liddell to Tamworth 330kV lines and installing Static VAr Compensators (SVCs) at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations. All material works associated with this upgrade are within Transgrid's network. Transgrid has now commissioned these works and Powerlink is working with Transgrid and AEMO on QNI tests to facilitate the release of additional capacity (refer to Section 6.14).

B.7 Joint planning with Energex and Ergon Energy

Queensland's Distribution Network Service Providers (DNSPs) Energex and Ergon Energy (part of the Energy Queensland Group) participate in regular joint planning and coordination meetings with Powerlink to assess emerging limitations, including asset condition drivers, to ensure the recommended solution is optimised for efficient expenditure outcomes[3]. These meetings are held regularly to assess, in advance of any requirement for an investment decision by either NSP, matters that are likely to impact on the other NSP. Powerlink and the DNSPs then initiate detailed discussions around addressing emerging limitations as required. Joint planning also ensures that interface works are planned to ensure efficient delivery.

Table B.1 provides a summary of activities that are utilised in joint planning. During preparation of respective regulatory submissions, the requirement for joint planning increases significantly and the frequency of some activities reflect this.

[3] Where applicable to inform and in conjunction with the appropriate RIT-T consultation process.

Table B.1 Joint planning activities

Activity	Frequency	
	As required	Annual
Sharing and validating information covering specific issues	Y	
Sharing updates to network data and models	Y	
Identifying emerging limitations	Y	
Developing potential credible solutions	Y	
Estimating respective network cost estimates	Y	
Developing business cases	Y	
Preparing relevant regulatory documents	Y	
Sharing information for joint planning analysis	Y	
Sharing information for respective works plans	Y	Y
Sharing planning and fault level reports		Y
Sharing information for Regulatory Information Notices		Y
Sharing updates to demand forecasts		Y
Joint planning workshops	Y	Y

B.7.1 Matters requiring joint planning

The following is a summary of projects where detailed joint planning with Energex and Ergon Energy (and other NSPs as required) has occurred since the publication of the 2023 TAPR (refer to Table B.2). There are a number of projects where Powerlink, Energex and Ergon Energy interface on delivery, changes to secondary systems or metering, and other relevant matters which are not covered in this Chapter. Further information on these projects, including timing and alternative options is discussed in Chapter 6.

Table B.2 Joint planning project references

Project	Reference
Maintaining reliability of supply to Kamerunga and Cairns northern beaches	Section 6.9.1
Maintaining reliability of supply and addressing condition risks at Ingham South	Section 6.9.2
Maintaining reliability of supply to between Ross and Dan Gleeson	Section 6.9.2
Maintaining reliability of supply to Gladstone South	Section 6.10.2
Maintaining reliability of supply at Ashgrove	Section 6.11.5
Maintain reliability of supply to the Brisbane metropolitan area	Section 6.11.5
Possible retirement of Loganlea 110/33kV transformer	Section 6.11.5

Note:

(1) Operational works, such as Overload Management Systems, do not form part of Powerlink's capital expenditure budget.

Appendix C Forecast of connection point maximum demands

Appendix C addresses National Electricity Rules (NER) (Clause 5.12.2(c)(1)[1] which requires the Transmission Annual Planning Report (TAPR) to provide 'the forecast loads submitted by a Distribution Network Service Provider (DNSP) in accordance with Clause 5.11.1 or as modified in accordance with Clause 5.11.1(d)'. This requirement is discussed below and includes a description of:

- the forecasting methodology, sources of input information and assumptions applied (Clause 5.12.2(c)(i)) (refer to Section C.1)
- a description of high, most likely and low growth scenarios (refer to Section C.2)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR that have changed significantly from forecasts provided in the TAPR from the previous year (refer to Section C.3)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR from the previous year which are significantly different from the actual outcome (refer to Section C.4).

C.1 Forecasting methodology used by Blunomy for maximum demand

VISION forecasting and planning (by Blunomy) was leveraged by Powerlink to forecast maximum and minimum demand across its network. Blunomy is a consulting company focussed on developing tools to operationalise the energy transition. VISION forecasting and planning by Blunomy is a network planning tool that supports networks preparing for the decarbonised and decentralised grid of the future. Blunomy was also engaged to develop a Consumer Energy Resources (CER) forecasts for Energy Queensland. These CER forecasts were leveraged to provide Powerlink its maximum demand forecasts.

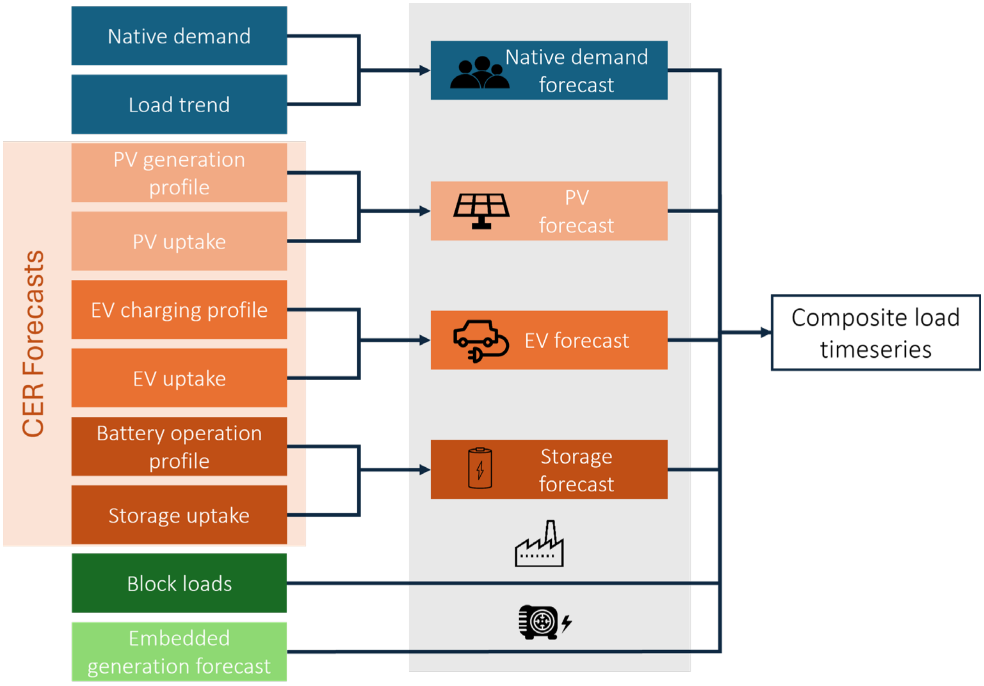
VISION provided Powerlink with 10-year forecasts of the 50% Probability of Exceedance[2] (PoE) and 10% PoE annual maximum demand. The forecast process individually models the different component of electricity demand: native demand, photovoltaic (PV), Electric vehicle (EV), BESS, block loads and embedded generation. It incorporates the latest assumptions for macro-economic factors and evolving trends in energy consumption and technology adoption, with sources including Australian Bureau of Statistics (ABS), Queensland Government, Australian Energy Market Operator (AEMO), Deloitte Access Economics economic forecasts, CSIRO GenCost reports, internal data from Energy Queensland and Powerlink.

The following sections provide a high-level overview of each sub model and the forecast process.

1 Where applicable, clauses 5.12.2 (1)(c)(iii) and (iv) are discussed in Chapter 3.

2 A 10% POE is a one in ten year maximum demand value: It would be expected, on average to observe a demand exceeding the 10% PoE once in ten years.

Figure C.1 Schematic of the building blocks of the forecast. Independent sub models are derived for the different CER technologies, native demand, trends, block loads and embedded generation. Composite load traces are constructed from the output of each sub model and used in a Monte-Carlo process to estimate Maximum Demand with PoE 10% and 50%.



Native demand model – weather and calendar sensitivity

VISION develops a model to estimate a probability distribution of demand conditional on weather and calendar conditions. VISION trains its demand model on the past 4 years of actual metered data (at half-hourly granularity) and leverages weather data sourced from ERA5. ERA5 is a high-resolution global weather dataset produced by the European Centre for Medium-Range Weather Forecasts (ECMWF). It provides hourly weather data from 1979 to the present, with a spatial resolution of approximately 31km, and includes a wide range of atmospheric variables. The model allows to sample a full year of demand data, at half hourly granularity, for a given “weather year”, which is a realisation of past weather conditions.

Load trends

VISION develops a regression model for average demand, incorporating historical population, GSP, Electricity prices, Energy Efficiency numbers from ABS, Queensland Government and AEMO, as well as Cooling Degree Days and Heating Degree Days. The trend is forecast for each scenario, with different assumptions made for these macro drivers. Vision applies a weighted trend for each asset in Powerlink’s network, based on a spatial forecast of population (at SA2 level from Queenland Government data) and the consumption split between residential, commercial and industrial customers (informed by EQL and Powerlink).

CER uptakes (developed with Energy Queensland)

VISION forecasts CER in a bottom-up (from feeders) and top down (at the Energex and Ergon network level) process. The bottom-up forecast uses spatially granular information and a top-down forecast captures macro-economic and technology factors. We then map and aggregate the EQL’s zone substations to Powerlink’s substations.

The bottom-up forecast is a technology adoption model, using historical technology stock (CER register for PV and EV, vehicle registration data for EV), as well as Statistical Area Level 2 (SA2) level ABS data. It defines per feeder s-curves of technology adoption.

The top-down forecast defines an adoption curve using historical and future GSP, population and technology prices.

A reconciliation process ensures that the top-down forecast is spatially consistent with the bottom-up forecast.

CER profiles (developed with Energy Queensland):
VISION derives load profiles for EV charging modelled through simulation of driving and charging for different vehicle types. The simulation leverages vehicle driving data sourced by Energy Queensland. The simulations provide different profiles for collaborative and convenience charging. The scenarios further define a glide path between the two types of charging to model changing patterns over the forecast horizon.

VISION derives load profiles for BESS through:

- a simulation process for "solar soaking" patterns
- an optimisation of the battery dispatch for customers with fixed tariffs
- an optimisation of the battery dispatch in the NEM for systems operating in the wholesale electricity market, using historical prices in the NEM.

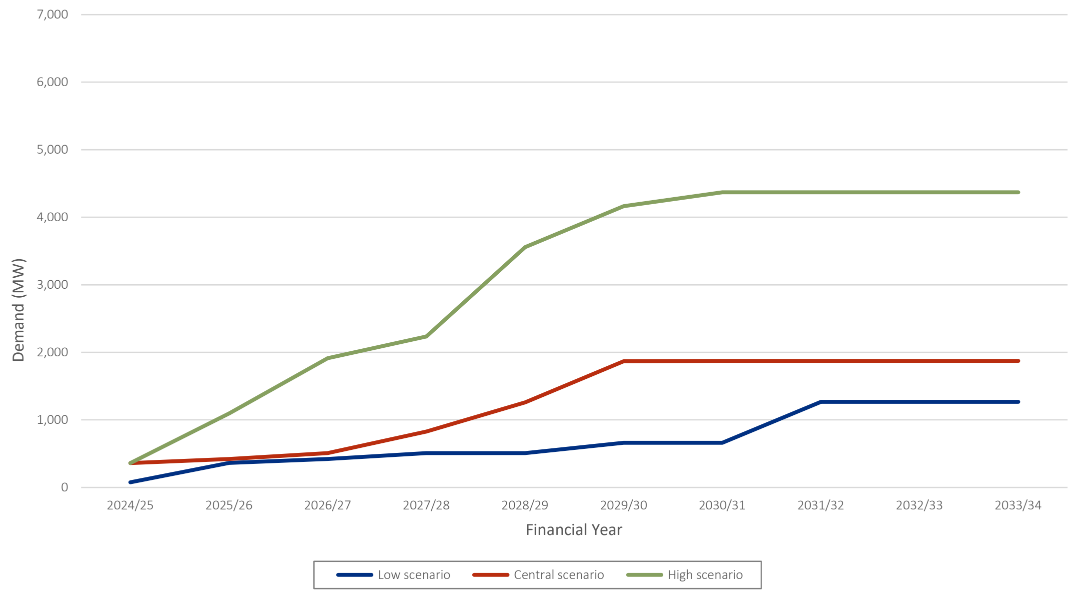
Similar to EVs, for each forecast scenario, a glide path between the different consumption patterns combines a nominal composite profile for BESS operation, evolving over the forecast horizon.

VISION estimates PV generation profiles using local historical weather conditions on each network asset.

Block loads

Powerlink and Energy Queensland provides the list of block loads added to the relevant high, central and low scenarios based on consultations with their customers. Block loads are defined by their capacity as well as by a profile archetype, from which VISION derives a modelled timeseries. Figure C.2 shows the block loads for the Low, Central and High scenarios.

Figure C.2 Block Loads



Generator model

VISION models embedded generators according to their types:

- non dispatchable renewable generation (PV and Wind) are modelled according to their capacity and historical weather conditions on site
- dispatchable generation is modelled through profile archetypes derived from historical meter data.

Forecast process

VISION combines the above sub-models to estimate POE forecast by a Monte-Carlo approach:

- for 10 Weather Years, n estimates of demand are sampled from the modelled probability distribution (native demand model): each sample is a full year worth of load (30min interval)
- the samples are scaled by the trend modelled (energy consumption trend model)
- the CER profiles are multiplied by their forecast uptakes and are added to the timeseries (CER model)
- block loads, with capacity and profiles defined by Powerlink, are added to the timeseries
- the generation is added to the timeseries (for a forecast of delivered demand)
- the Maximum demand of each composite sample is recorded.

VISION derives the 50% and 10% POE maximum demand from these 10 x n samples of maximum demand.

C.2 Description of Powerlink's high, central and low growth scenarios for maximum demand

The scenarios developed for the high, central and low case maximum demand forecasts were prepared in June 2024 based on the most recent information. The assumptions for the Powerlink forecast of demand are consistent with the assumptions for the CER forecast developed with Energy Queensland.

High growth scenario assumptions for maximum demand

- GSP – High growth, averaging 2.8% per annum in the forecast horizon
- Queensland regional population growth – High growth, averaging 2% per annum in the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, stable afterwards
- Energy efficiency – AEMO's Green energy exports scenario (2023)
- EV price parity reached in 2027, share of collaborating charging growing from 10% to 50% by 2036
- Battery charging profiles – Fast increasing participation in VPP programs, from 20% to 65% in 2037
- PV prices – CSIRO Global NZE by 2050 scenario (GenCost 2023), rebased on historical retail prices.

Central scenario assumptions for maximum demand

- GSP – Medium growth, averaging 2% per annum in the forecast horizon
- Queensland regional population growth – Medium growth, decreasing to 1.6% per annum in the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, followed by an increase at .7% per annum
- Energy efficiency – AEMO's Step change scenario (2023)
- EV price parity reached in 2030, share of collaborating charging growing from 8% to 40% by 2036
- Battery charging profiles –Increasing participation in VPP programs, from 17% to 55% in 2037
- PV prices –CSIRO Current Policies scenario (GenCost 2023), rebased on historical retail prices.

Low growth scenario assumptions for maximum demand

- GSP – Slow growth, averaging 1.2% per annum in the forecast horizon
- Queensland regional population growth – Slow growth, decreasing from current levels to 1% per annum over the forecast horizon. Refer to Figure C.6
- Electricity Prices – Decreasing prices until 2027, followed by a faster increase at 1.4 % per annum
- Energy efficiency – AEMO's Progressive change scenario (2023)
- EV price parity reached in 2033, share of collaborating charging growing from 5% to 15% by 2036
- Battery charging profiles – Low participation in VPP programs, increasing from 5% to 12% in 2037
- PV prices – CSIRO Global NZE post 2050 scenario (GenCost 2023), rebased on historical retail prices.

Figure C.3 Embedded battery energy storage system – Capacity

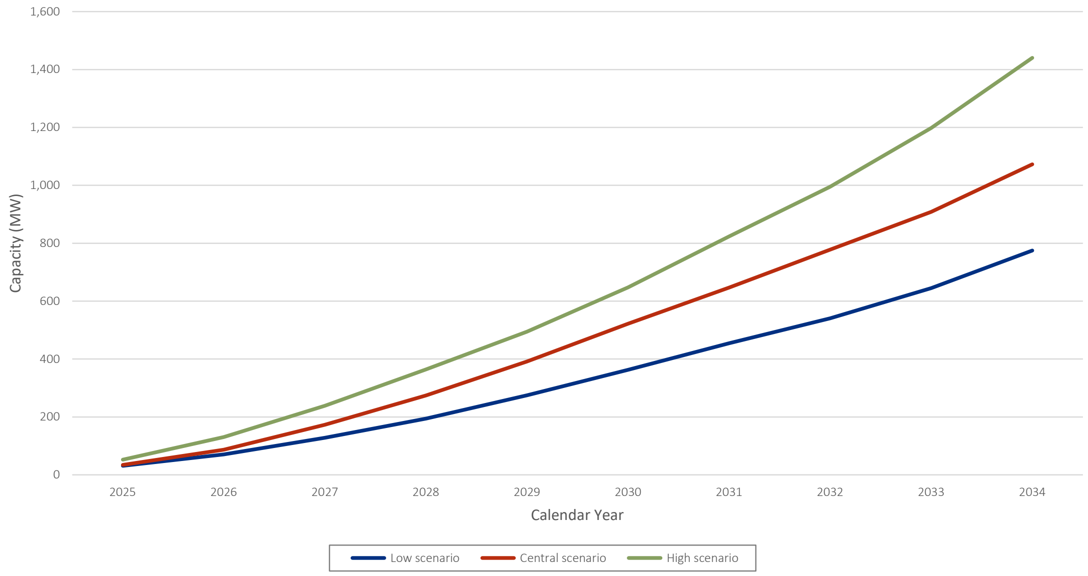


Figure C.4 Embedded battery energy storage system – Energy

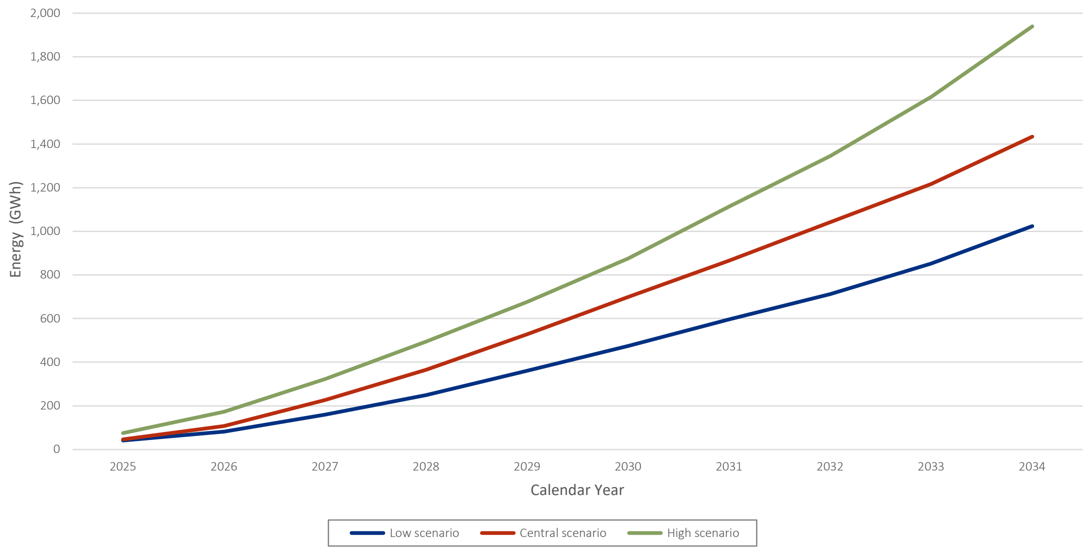


Figure C.5 Rooftop PV uptake – Capacity

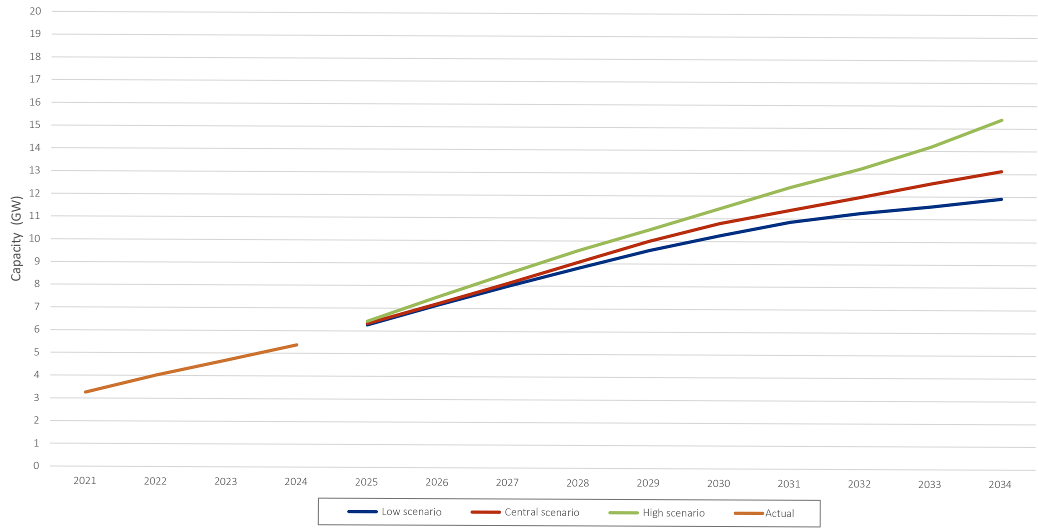


Figure C.6 Population

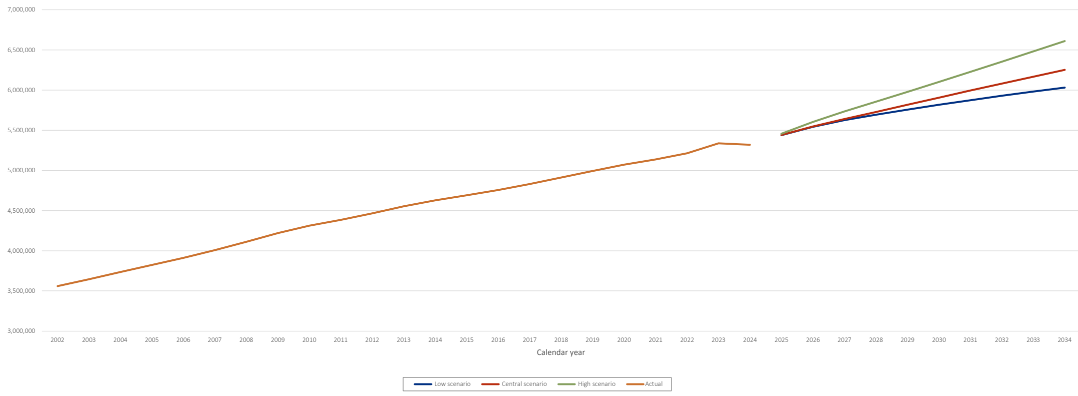
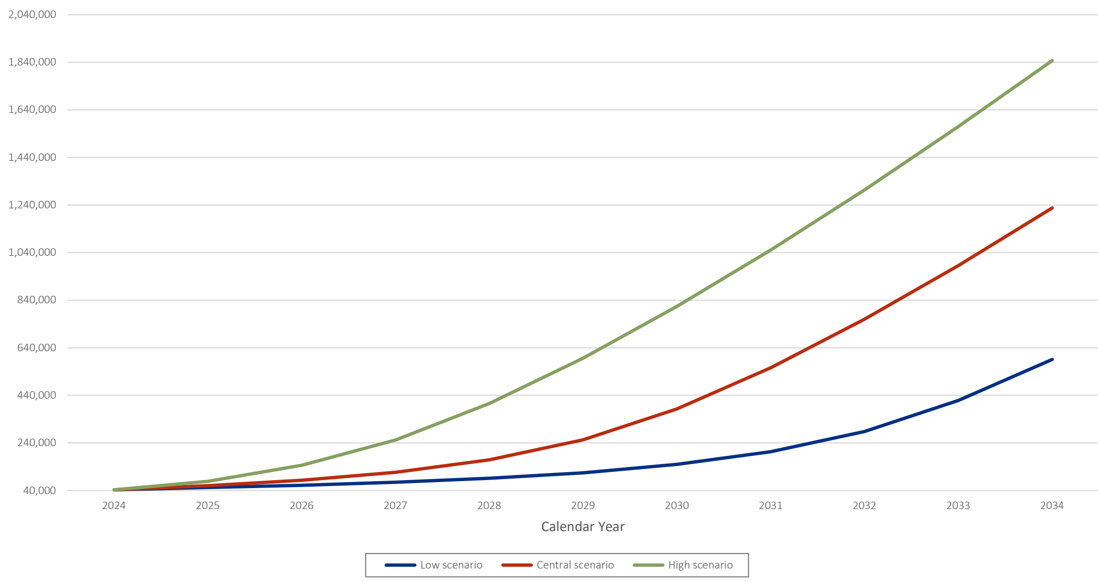


Figure C.7 Electric Vehicle uptake



C.3 Significant changes to the connection point maximum demand forecasts

Major differences between the 2024 forecast and the 2023 forecast can generally be attributed to natural variation in peaks below the connection point level, which can result in displaying an associated variation in year on year changes at the connection point level, and with changes in the growth in the lower levels of the network rather than from any network configuration changes or significant block loads. Changes in proposed block loads also account for differences. These, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

Table C.1 Ergon connection points with the greatest difference in growth between the 2024 and 2023 forecasts

Connection Point	kV	Change in growth rate (per annum)
Blackwater	132	-8%
Turkinje (Craiglie and Lakeland)	132	-3%

Table C.2 Energex connection points with the greatest difference in growth between the 2024 and 2023 forecasts

Connection Point	kV	Change in growth rate (per annum)
Abermain	33	-2%
Ashgrove West	110	-2%
Bundamba	110	-2%
Blackstone (Raceview)	110	-1%

C.4 Significant differences to actual observations

The 2023/24 summer was relatively hotter across large parts of Queensland when compared to recent seasons. This, combined with natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2023 forecast values for 2023/24 and what was observed.

Table C.3 Ergon connection points with the greater than 10% absolute difference between the peak 2023/24 and corresponding base 2023 forecast for 2023/24

Connection Point	2023/24 forecast peak	2023/24 actual peak	Difference
Ashgrove West	78	112	44%
Woolooga (Gympie)	228	265	19%
Molendinar	536	596	11%
Sumner	33	36	11%
Middle Ridge	114	96	-16%

Table C.4 Energex connection points with the greater than 10 % absolute difference between the peak 2023/24 and corresponding base 2023 forecast for 2023/24

Connection Point	2023/24 forecast peak	2023/24 actual peak	Difference
Chinchilla	16	21	28%
Woree (Cairns North)	51	62	21%
Oakey	17	20	20%
Edmonton	46	55	19%
Townsville East	37	44	19%
Townsville South	93	110	19%
Biloela	29	34	19%
Tarong	47	55	18%
Bulli Creek (Waggamba)	20	23	16%
Middle Ridge	229	265	15%
Gin Gin	176	195	11%
Moranbah	145	107	-26%
Lilyvale	141	103	-27%
Newlands	24	15	-36%

C.5 Customer forecasts of connection point maximum demands

Tables C.1 to C.18 which are available on Powerlink's website, show 10-year forecasts of native summer and winter demand at connection point peak, for high, central and low growth scenarios (refer to Appendix C.2). These forecasts have been supplied by Powerlink direct connect customers and have been produced by Powerlink.

The connection point Megavolt Ampere reactive power (MVAr) forecast includes the effect of customer's downstream capacitive compensation.

Groupings (sums of non-coincident forecasts) of some connection points are used to protect the confidentiality of specific customer loads.

In tables C.1 to C.18 the zones in which connection points are located are abbreviated as follows:

FN	Far North zone
R	Ross zone
N	North zone
NW	North West
CW	Central West zone
G	Gladstone zone
WB	Wide Bay zone
S	Surat zone
B	Bulli zone
SW	South West zone
M	Moreton zone
GC	Gold Coast zone

Appendix D Possible network investments for the 10-year outlook period

As a result of the annual planning review, Powerlink has identified that the investments listed in this appendix are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the 10-year outlook period. Potential projects have been grouped by Region and zone as described in Chapter 6. It should be noted that the indicative cost of potential projects also excludes known and unknown contingencies. Additional information on these potential projects, as required by the Australian Energy Regulator's Transmission Annual Planning Report Guidelines, is made available in the TAPR templates which can be accessed through Powerlink's TAPR portal. Where appropriate, the technical envelope for potential non-network solutions has been included in the relevant table.

D.1 Northern Region

Table D.1 Possible network investments in the Far North zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Rebuild the 132kV transmission line between Woree and Kamerunga substations and Kamerunga 132kV Substation rebuild	New 132kV double circuit transmission line, substation establishment on a new site and associated Ergon 22kV works	Maintain supply reliability to the Far North zone	December 2028	Two 132kV single circuit transmission lines, substation establishment on a new site and associated Ergon 22kV works (2)	$200m
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations	Staged line refit works on steel lattice structures	Maintain supply reliability to the Far North and Ross zones	Staged works by June 2029 (1)	New transmission line (2)	$35m (3)
Substations					
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2029	Life extension of the existing transformer or a non-network alternative of up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully	$6m
Edmonton 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2030	Selected replacement of 132kV secondary systems	$9m (3)
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2031	Selected replacement of 132kV secondary systems	$4m (3)
Chalumbin 275kV and 132kV primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Far North zone	June 2028 (1)	Full replacement of all 275kV and 132kV primary plant and secondary systems	$9m
275/132kV substation establishment to maintain supply to Turkinje substation	Establishment of 275/132kV switching substation near Turkinje including two transformers	Maintain supply reliability to Turkinje area	June 2030	Refit of the Chalumbin to Turkinje 132kV transmission line	$37m (3)
Woree 275kV and 132kV secondary systems replacement	Selected replacement of 275kV and 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2034	Full replacement of 275kV and 132kV secondary systems	$17m
El Arish 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2034	Full replacement of 275kV and 132kV secondary systems	$10m (3)

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.9.1.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects

D.1.2 Ross zone

Table D.2 Possible network investments in the Ross zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Dan Gleeson and Alan Sherriff substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028 (1)	New 132kV transmission line (2)	$5m
Line refit works on the 132kV transmission line between Ross and Dan Gleeson substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028 (1)	New 132kV transmission line (2)	$8m
Targeted refit of the 275kV transmission line between Strathmore and Ross	Targeted refit of the 275kV transmission line between Strathmore and Ross	Maintain supply reliability to the Ross zone	June 2030	New 132kV transmission line (2)	$10m
Substations					
Ingham South 132kV primary plant and secondary systems replacement	Full replacement of 132kV primary plant and secondary systems	Maintain supply reliability to the Ross zone	December 2027	Selected replacement of 132kV primary plant and secondary systems Up to 20MW at peak and up to 280MWh per day on a continuous basis to provide supply to the 66kV network at Ingham South	$27m (3)
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2027 (1)	Selected replacement of 132kV secondary systems Up to 120MW at peak and up to 860MWh per day to support the 66kV network in north east Townsville	$10m
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2027 (1)	Full replacement of 132kV secondary systems Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kv network in north east Townsville	$14m (3)

Table D.2 Possible network investments in the Ross zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2033	Full replacement of secondary systems	$4m
Townsville South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2033	Full replacement of 132kV secondary systems Up to 150MW at peak and up to 3,000MWh per day to provide supply to Townsville East and Townsville South (including Sun Metals)	$11m
Yabulu South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034	Full replacement of 132kV secondary systems	$14m (3)
Clare South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034	Full replacement of 132kV secondary systems	$14m (3)
Ross 275kV and 132kV secondary systems replacement	Selected replacement of 275kV and 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2035	Full replacement of 275kV and 132kV secondary systems	$10m

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in this Section 6.9.2

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects

D.1.3 North zone

Table D.3 Possible network investments in the North zone in the 10-year outlook period

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Nebo Substation and Eton tee	Line refit works on steel lattice structures	Maintain supply reliability to the North zone	December 2027 (1)	New transmission line (2)	$31m (3)
Line refit works on the 132kV transmission line between Collinsville North, Strathmore and Clare South substations	Line refit works on the 132kV transmission line	Maintain supply reliability to the North zone	June 2035	Rebuild of the 132kV transmission line between Collinsville North, Strathmore and Clare South substations (2)	$44m

Table D.3 Possible network investments in the North zone in the 10-year outlook period *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Alligator Creek 132kV primary plant and SVC secondary systems replacement	Selected replacement of 132kV primary plant and SVC secondary systems replacement	Maintain supply reliability to the North zone	June 2028 (1)	Full replacement of 132kV primary plant and SVC secondary systems replacement	$14m (3)
North Goonyella 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2027 (1)	Selected replacement of 132kV secondary systems	$6m
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the North zone	June 2026	Staged replacement of secondary systems (2)	$12m
Pioneer Valley 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2035 (1)	Full replacement of 132kV primary plant	$3m (3)
Strathmore 275kV and 132kV secondary systems replacement	Selected replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the North zone	June 2034	Selected replacement of 275kV and 132kV secondary systems in existing panels	$15m
Mackay 132/33kV transformer replacement	Replacement of one 132/33kV transformer	Maintain supply reliability to the North zone	June 2030	Establish 33kV supply from surrounding network (2)	$5m (3)
Nebo SVC secondary systems replacement	Selected replacement of SVC secondary systems	Maintain supply reliability to the North zone and	June 2033	Full replacement of SVC secondary systems	$7m
Nebo SVC selected primary plant replacement and SVC transformer life extension	Full replacement of primary plant and transformer associated with the SVC	Maintain supply reliability to the North zone	December 2029	Full replacement of SVC primary plant and SVC transformer	$8m
Alligator Creek 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2035	Full replacement of 132kV secondary systems	$15m

Notes:

(1) The revised timing from the 2023 TAPR is based upon the latest condition assessment.

(2) The envelope for non-network solutions is defined in Section 6.9.3.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

D.2 Central region

D.2.1 Central west zone

Table D.4 Possible network investments in the Central West zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations	Line refit works on the 275kV transmission line	Maintain supply reliability in the Central West zone and Northern region	December 2026 (1)	Stanwell to Broadsound second side stringing New 275kV transmission line between Bouldercombe and Broadsound substation (2)	$15m (3)
Line refit works on the 132kV transmission line between Bouldercombe tee and Egans Hill Substation	Line refit works on the 275kV transmission line	Maintain supply reliability in the Central West zone	June 2033	Rebuild the 275kV transmission line between Bouldercombe tee and Egans Hill Substation (2)	$4m
Line refit works on the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations	Line refit works on the 132kV transmission line	Maintain supply reliability in the Central West zone	June 2035	Rebuild the 132kV transmission line between Collinsville North, Goonyella Riverside and Moranbah substations (2)	$58m
Line refit works on the 132kV transmission line between Moranbah, Kemmis and Nebo substations	Line refit works on the 132kV transmission line	Maintain supply reliability in the Central West zone	June 2035	Rebuild the 132kV transmission line between Moranbah, Kemmis and Nebo substations (2)	$40m
Substations					
Blackwater 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Central West zone	June 2026 (1)	Full replacement of 132kV primary plant	$3m
Biloela 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Central West zone	June 2033	Full replacement of 132kV secondary systems	$7m (3)
Broadsound 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability to the Central West zone	June 2032	Full replacement of 275kV secondary systems	$10m (3)
Broadsound 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	June 2028 (1)	Full replacement of 275kV primary plant (2)	$19m
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2033	Full replacement of 132kV secondary systems	$5m (3)

Table D.4 Possible network investments in the Central West zone *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Calvale 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2027 (1)	Full replacement of 275kV primary plant (2)	$18m
Blackwater 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2034	Full replacement of 132kV secondary systems	$19m (3)
Nebo 132kV and 275kV secondary systems replacement	Selected replacement of 132kV and 275kV secondary systems	Maintain supply reliability to the Central West and North zones	June 2034	Full replacement of 132kV and 275kV secondary systems	$15m (3)
Stanwell 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central west zone and Northern region	December 2032	Full replacement of 275kV primary plant	$22m

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.10.1.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

D.2.2 Gladstone zone

Table D.5 Possible network investments in the Gladstone zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission line between Wurdong and Boyne Island	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2030 (1)	Rebuild the 275kV transmission line between Wurdong and Boyne Island (2)	$5m
Rebuild the 132kV transmission line between Calliope River and Gladstone South Substation	Rebuild the 132kV transmission line between Calliope River and Gladstone South substations	Maintain supply reliability in the Gladstone zone	June 2030 (1)	Line refit works on steel lattice structures (2)	$75m (3)
Line refit works on steel lattice structures on the 275kV transmission line between Raglan and Bouldercombe substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	June 2031 (1)	Rebuild the 275kV transmission line between Raglan and Larcom Creek (2)	$19m (3)

Table D.5 Possible network investments in the Gladstone zone *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Line refit works on the 132kV transmission line between Bouldercombe substation and Bouldercombe Tee	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	June 2030	Rebuild the 132kV transmission line between Bouldercombe and Bouldercombe Tee (2)	$3m
Line refit works on the 275kV transmission line between Calliope River and Boyne Island	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	June 2032	Rebuild the 275kV transmission line between Calliope River and Boyne Island (2)	$15m
Substations					
Callemondah selected 132kV primary plant and secondary systems replacement	Selected replacement of 132kV primary plant and secondary systems	Maintain supply reliability in the Gladstone zone	June 2027 (1)	Full replacement of 132kV primary plant and secondary systems	$7m (3)
Rockhampton 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain reliability in Rockhampton	June 2031	Full replacement of 132kV secondary systems	$6m (3)
Larcom Creek 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034	Full replacement of the 275kV secondary systems	$14m (3)
Pandoin 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034	Selected replacement of 132kV secondary systems	$6m (3)
Wurdong 275kV selected primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability in the Gladstone zone	June 2032	Full replacement of 275kV primary plant	$15m
Yarwun 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034	Full replacement of 132kV secondary systems	$17m

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.10.2.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

D.3 Southern region

D.3.1 Wide Bay zone

Table D.6 Possible network investments in the Wide Bay zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Rebuild of the 275kV transmission line between Calliope River Substation and the Wurdong Tee	New double circuit transmission line for the first 15km out of Calliope River substation	Maintain supply reliability to the CQ-SQ transmission corridor (and Gladstone zone)	December 2032 (2)	Refit the two single circuit 275kV transmission lines	$50m (1)
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Substation	Refit the single circuit 275kV transmission line between Calliope River Substation and Wurdong Substation	Maintain supply reliability in the CQ-SQ transmission corridor (and Gladstone zone)	June 2031 (2)	Rebuild the 275kV transmission line as a double circuit	$14m (1)
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	Refit the 275kV transmission line between Woolooga and South Pine substations	Maintain supply reliability to the Moreton zone	June 2029	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$20m (1)
Targeted reinvestment in the 275kV transmission lines between Wurdong Tee and Gin Gin substation	Refit the 275kV transmission line between Wurdong Tee and Gin Gin Substation	Maintain supply to the Wide Bay zone	December 2032	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$85m (1)
Line refit works on the 275kV transmission line between South Pine and Palmwoods substations	Line refit works on steel lattice structures	Maintain supply to the Wide Bay zone	June 2032	Rebuild 275kV transmission line between South Pine and Palmwoods substations	$12m (1)
Line refit works on the 275kV transmission line between Gin Gin and Woolooga substations	Rebuild the 275kV transmission line between Gin Gin and Woolooga substations	Maintain supply to the Wide Bay zone	June 2032 (2)	Refit the 275kV transmission line between Gin Gin and Woolooga substations	$37m (1)
Line refit works on the 275kV transmission line between Gin Gin and Calliope River substations	Refit the 275kV transmission line between Gin Gin and Calliope River substations	Maintain supply to the Wide Bay zone	June 2031	Rebuild the 275kV transmission line between Gin Gin and Calliope River substations (2)	$4m
Substations					
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2033	Selected replacement of 132kV and 275kV secondary systems	$19m

Table D.6 Possible network investments in the Wide Bay zone *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Woolooga 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply to the Wide Bay zone	June 2030 (2)		$3m (1)
Woolooga 275kV and 132kV and SVC secondary systems replacement	Full replacement of 275kV, 132kV and SVC secondary systems.	Maintain supply to the Wide Bay zone	December 2034	Selected replacement of 275kV, 132kV and SVC secondary systems	$43m
Palmwoods 275kV and 132kV selected primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Wide Bay zone	June 2034 (2)	Full replacement of 275kV and 132kV primary plant	$15m
Palmwoods 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Wide Bay zone	June 2035	Full replacement of 132kV secondary systems	$21m

Notes:

(1) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(2) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

D.3.2 Surat zone

Table D.7 Possible network investments in the Surat zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Columboola 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Surat zone	June 2033	Full replacement of secondary systems	$17m

D.3.3 Bulli zone

Table D.8 Possible network investments in the Bulli zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Millmerran 330kV AIS secondary systems replacement	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	December 2031	Full replacement of secondary systems	$6m
Braemar 330kV secondary systems replacement non-iPASS	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	June 2034	Full replacement of secondary systems	$23m
Bulli Creek 330/132kV transformer replacement	Replace one 330/132kV transformer at Bulli Creek Substation	Maintain supply reliability in the Bulli zone	June 2031	Retirement of 330/132kV transformers with non-network support	$7m

D.3.4 South West zone

Table D.9 Possible network investments in the South West zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Middle Ridge 110kV primary plant replacement	Selected replacement of selected 110kV primary plant	Maintain reliability of supply in the South West zone	June 2028	Full replacement of 110kV primary plant	$3m
Middle Ridge 275kV and 110kV secondary systems replacement	Selected replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the South West zone	December 2033	Full replacement of 275kV and 110kV secondary systems	$39m
Tarong 275kV, 132kV and 66kV secondary systems replacement	Selected replacement of 275kV, 132kV and 66kV secondary systems	Maintain supply reliability in the South West zone	June 2035	Full replacement of 275kV, 132kV and 66kV secondary systems	$33m

D.3.5 Moreton zone

Table D.10 Possible network investments in the Moreton zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	Replace the 110kV underground cable between Upper Kedron and Ashgrove West substations using an alternate easement	Maintain supply reliability in the Moreton zone	June 2028	In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (2)	$31m(3)
Line refit works on the 110kV transmission line between Richlands and Algester substations	Refit the 110kV transmission line between Richlands and Algester substations	Maintain supply reliability in the Moreton zone	June 2028	Potential retirement of the transmission line between Richlands and Algester substations	$2m
Line refit works on the 110kV transmission line between Blackstone and Abermain substations	Refit the 110kV transmission line between Blackstone and Abermain substations	Maintain supply reliability in the Moreton zone	June 2033	Rebuild the 110kV transmission line between Blackstone and Abermain substations	$8m
Line refit works on the 275kV transmission line between Bergins Hill and Karana Downs	Refit the 275kV transmission line between Bergins Hill and Karana Downs substations	Maintain supply reliability in the Moreton zone	June 2030	Rebuild or replace the transmission line between Bergins Hill and Karana Downs substations	$4m
Line refit works on the 275kV transmission line between Karana Downs and South Pine	Refit the 275kV transmission line between Karana Downs and South Pine substations	Maintain supply reliability in the Moreton zone	June 2030	Rebuild the 275kV transmission line between Karana Downs and South Pine substations	$14m

Table D.10 Possible network investments in the Moreton zone *(continued)*

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Line refit works on the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	Refit the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	Maintain supply reliability in the Moreton zone	June 2034	Rebuild the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	$14m
Line refit works on the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	Refit the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	Maintain supply reliability in the Moreton zone	December 2030	Rebuild the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	$20m
Line refit works on the 110kV transmission line between West Darra and Upper Kedron substations	Refit the 110kV transmission line between West Darra and Upper Kedron substations	Maintain supply reliability in the Moreton zone	June 2032	Rebuild the 110kV transmission line between West Darra and Upper Kedron substations	$5m
Substations					
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2027 (1)	Staged replacement of 110kV secondary systems	$22m
Murarrie 275kV and 110kV secondary systems replacement	Full replacement of 110kV secondary systems and selected replacement of 275kV secondary systems	Maintain supply reliability in the Moreton zone	December 2027 (1)	Staged replacement of 110kV secondary systems and selected 275kV secondary systems	$21m
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2032	Staged replacement of 110kV secondary systems	$14m (3)
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 110kV secondary systems	$10m (3)
South Pine 275kV and SVC secondary systems replacement	Full replacement of 275kV and SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 275kV and SVC secondary systems	$57m (3)
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 275kV and 110kV secondary systems	$20m
West Darra 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 110kV secondary systems	$12m (3)
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2033 (1)	Life extension of one 275/110kV transformer at Rocklea	$5m
Loganlea 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2031 (1)	Staged replacement of 275kV primary plant	$5m

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Greenbank SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	December 2029	Staged replacement of SVC secondary systems	$8m (3)
Mount England 275kV primary plant and secondary systems replacement	Full replacement of 275kV secondary systems and staged replacement of primary plant	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 275kV secondary systems and primary plant	$10m (3)
Belmont 11kV underground cable and transformers replacement	Full replacement of two 11kV underground cables between Belmont and Mansfield and associated transformers	Maintain supply reliability in the Moreton zone	December 2026		$8m
Belmont 110kV and 275kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of 275kV and 110kV secondary systems	$24m
Belmont 33kV and 11kV primary plant replacement	Full replacement of 33kV and 11kV primary plant	Maintain supply reliability in the Moreton zone	June 2032	Staged replacement of 22kV and 11kV primary plant	$3m (3)
South Pine 275kV primary plant replacement	Staged replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	December 2030 (1)	Full replacement of 275kV primary plant	$5m
Abermain 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2032	Staged replacement of 275kV and 110kV secondary systems	$10m (3)
Abermain 275kV and 110kV primary plant replacement	Selected 275kV and 110kV primary plant replacement	Maintain supply reliability in the Moreton zone	June 2030 (1)	Full replacement of 275kV and 110kV primary plant	$8m
Greenbank 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	June 2035	Staged replacement of 275kV secondary systems	$30m

Notes:

(1) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.11.5.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

D.3.6 Gold Coast zone

Table D.11 Possible network investments in the Gold Coast zone

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 110kV transmission line between Mudgeeraba Substation and Terranora	Targeted line refit works on steel lattice structures	Maintain supply reliability from Queensland to NSW Interconnector	June 2028 (2)	Full line refit New transmission line (1)	$5m
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	Targeted line refit works on steel lattice structures	Maintain supply reliability in the Gold Coast zone	June 2029 (2)	New double circuit 275kV transmission line (1)	$37m (3)
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2027 (2)	Selected replacement of 275kV secondary systems	$23m
Mudgeeraba 110kV primary plant and secondary systems replacement and 275/110kV transformer replacement	Selected replacement of 110kV primary plant and staged replacement of 110kV secondary systems and replacement of the transformer	Maintain supply reliability in the Gold Coast zone	December 2030 (2)	Full replacement of 110kV secondary systems and replacement of the transformer(1)	$54m (3)

Notes:

(1) The envelope for non-network solutions is defined in Section 6.11.6.

(2) The change in timing of the network solution from the 2023 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2023 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

Appendix E TAPR templates methodology

The NER, the Australian Energy Regulator (AER) Transmission Annual Planning Report (TAPR) Guidelines[1] set out the required format of TAPRs, in particular the provision of TAPR templates to complement the TAPR document. The purpose of the TAPR templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are strongly encouraged to contact Powerlink in the first instance.

The TAPR template data may be directly accessed on Powerlink's TAPR portal[2]. Alternatively please contact NetworkAssessments@powerlink.com.au for assistance.

E.1 Context

While care is taken in the preparation of TAPR templates, data is provided in good faith. Powerlink Queensland accepts no responsibility or liability for any loss or damage that may be incurred by persons acting in reliance on this information or assumptions drawn from it.

The proposed preferred investment and associated data is indicative, has the potential to change and will be technically and economically assessed under the Regulatory Investment Test for Transmission (RIT-T) consultation process as/if required at the appropriate time. TAPR templates may be updated at the time of RIT-T commencement to reflect the most recent data and to better inform non-network providers[3]. Changes may also be driven by the external environment, advances in technology, non-network solutions and outcomes of other RIT-T consultations which have the potential to shape the way in which the transmission network develops.

There is likely to be more certainty in the need to reinvest in key areas of the transmission network which have been identified in the TAPR in the near term, as assets approach their anticipated end of technical service life. However, the potential preferred investments (and alternative options) identified in the TAPR templates undergo detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This nearterm analysis provides Powerlink with an additional opportunity to deliver greater benefits to customers through improving and further refining options. In the medium to long-term, there is less certainty regarding the needs or drivers for reinvestments. As a result, considerations in the latter period of the annual planning review require more flexibility and have a greater potential to change in order to adapt to the external environment as the NEM evolves and customer behaviour changes.

Where an investment is primarily focussed on addressing asset condition issues, Powerlink has not attempted to quantify the impact on the market e.g. where there are market constraints arising from reconfiguration of the network around the investment and Powerlink considers that generation operating within the market can address this constraint.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

E.2 Methodology/principles applied

The AER's TAPR Guidelines incorporate text to define or explain the different data fields in the template. Powerlink has used these definitions in the preparation of the data within the templates.

For connection point templates the expected unserved energy (EUSE) has been calculated using aggregated failure statistics for network assets, considering both momentary and sustained failures by the following expression:

EUSE = Probability of Asset Failure × Median Restoration time × MW @ Risk

For lines segments templates the expected unserved energy should be interpreted as then annual energy that cannot be supplied by that asset under system normal conditions.

Further to the AER's data field definitions, Powerlink provides details on the methodology used to forecast the daily demand profiles. Table B.1 also provides further context for some specific data fields.

The data fields are denoted by their respective AER Rule designation, TGCPXXX (TAPR Guideline Connection Point) and TGTLXXX (TAPR Guideline Transmission Line).

1 First published in December 2018.
2 Refer to the TAPR portal.
3 Separate to the publication of the TAPR document which occurs annually.

E.3 Development of daily demand profiles

Forecasts of the daily demand profiles for the days of annual maximum and minimum demands over the next 10 years were developed using VISION forecasting and planning (by Blunomy). These daily demand profiles are an estimate and should only be used as a guide. For further context and explanation of the methodology used to develop minimum and maximum demand profiles refer to appendix C.1.

The 10-year forecasts of daily demand profiles that have been developed for the TAPR templates include:

- 50% probability of exceedance (PoE) maximum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- Minimum demand, MVA (TGCP008).

Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value.

- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011).

The maximum demand forecast on the minimum demand day (TGCP009) and the forecast daily demand profile on the minimum demand day (TGCP011) were determined from the minimum (annual) daily demand profiles.

Table E.1 Further definitions for specific data fields

Data field	Definition
TGCP013 and TGTL008 Maximum load at risk per year	The load at risk takes into account both the network topology and aggregated outage and asset failure statistics for lines, transformers, and switching assets across the network. Where detailed project scopes and project requirements have not been determined, the aggregation of impacted loads were deemed at risk.
TGCP016 and TGTL011 Preferred investment - capital cost	The timing reflected for the estimated capital cost is the year of proposed project commissioning. RIT-Ts to identify the preferred option for implementation would typically commence three to five years prior to this date, relative to the complexity of the identified need, option analysis required and consideration of the necessary delivery timeframes to enable the identified need to be met. To assist non-network providers, RIT-Ts in the nearer term are identified in Table 6.6.
TGCP017 and TGTL012 Preferred investment - Annual operating cost	Powerlink has applied a standard 2% of the preferred investment capital cost to calculate indicative annual operating costs.
TGCP024 Historical connection point rating	Includes the summer and winter ratings for the past three years at the connection point. The historical connection point rating is based on the most limiting network component on Powerlink's network, in transferring power to a connection point. However lower downstream distribution connection point ratings could be more limiting than the connection point ratings on Powerlink's network.
TGCP026 Unplanned outages	Unplanned outage data relates to Powerlink's transmission network assets only. Forced and faulted outages are included in the data provided. Information provided is based on calendar years from January 2018 to December 2020.
TGPC028 and TGTL019 Annual economic cost of constraint	The annual economic cost of the constraint is the direct product of the annual expected unserved energy and the Value of Customer Reliability (VCR) related to the investment. It does not consider cost of safety risk or market impacts such as changes in the wholesale electricity cost or network losses.
TGTL005 Forecast 10-year asset rating	Asset rating is based on an enduring need for the asset's functionality and is assumed to be constant for the 10-year outlook period.
TGTL017 Historical line load trace	Due to the meshed nature of the transmission network and associated power transfers, the identification of load switching would be labour intensive and the results inconclusive. Therefore the data provided does not highlight load switching events.

Appendix F Zone and grid section definitions

This Appendix provides definitions of the 13 geographical zones and nine grid sections referenced in this Transmission Annual Planning Report (TAPR).

Tables F.1 and F.2 provide detailed definitions of zone and grid sections.

Table F.3 provides details of the name and type of generation connected to the transmission system in each zone.

Figure F.1 provides illustrations of the grid section definitions.

Table F.1 Zone definitions

Zone	Area covered
Far North	North of Guybal Munjan and Tully
Ross	North of King Creek and Bowen North, excluding the Far North and North West zones
North West	Mount Isa and Cloncurry
North	North of Broadsound and Dysart, excluding the Far North, North West and Ross zones
Central West	South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone
Gladstone	South of Raglan, north of Gin Gin and east of Calvale
Wide Bay	Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie
Surat	West of Western Downs and south of Moura, excluding the Bulli zone
Bulli	Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Middle Ridge
South West	Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli zone
Moreton	South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone
Gold Coast	East of Greenbank, south of Coomera to the Queensland/New South Wales border

Table F.2 Grid section definitions (1)

Grid section	Definition
FNQ	Guybal Munjan into Chalumbin 275kV (2 circuits) Ross/Tully into Woree 275kV (1 circuit) Tully into El Arish 132kV (1 circuit)
NWQ	Flinders to Future 500kV substation in Ross area (2 circuits)
CQ-NQ	Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)
Gladstone	Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit)
CQ-SQ	Wurdong to Teebar Creek 275kV (1 circuit) Calliope River to Gin Gin/Woolooga 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)
Surat	Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit)
SWQ	Western Downs to Halys 275kV (1 circuit) Western Downs to Coopers Gap 275kV (1 circuit) Braemar (East) to Halys 275kV (2 circuits) Tummaville to Middle Ridge 330kV (2 circuits)
Tarong	Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)
Gold Coast	Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)

Note:

(1) The grid sections defined are as illustrated in Figure F.1. X into Y – the MW flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

Table F.3 Zone Generation details

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
Far North	Barron Gorge			•				
	Kareeya			•				
	Koombooloomba			•				
	Mt Emerald					•		
	Kaban					•		
Ross	Townsville		•					
	Mt Stuart		•					
	Kidston (1)			•				
	Clare				•			
	Haughton				•			
	Ross River				•			
	Sun Metals				•			
	Invicta							•
North	Daydream				•			
	Hamilton				•			
	Hayman				•			
	Whitsunday				•			
	Rugby Run				•			
Central West	Callide B	•						
	Callide PP	•						
	Stanwell	•						
	Lilyvale				•			
	Moura				•			
	Broadsound (1)				•			
	Lotus Creek (1)					•		
	Clarke Creek (1)					•		
	Boulder Creek (1)					•		
	Bouldercombe						•	
Gladstone	Gladstone	•						
	Yarwun		•					
Wide Bay	Woolooga Energy Park				•			
	Woolooga (1)						•	
Moreton	Swanbank E		•					
	Wivenhoe			•				
	Greenbank						•	

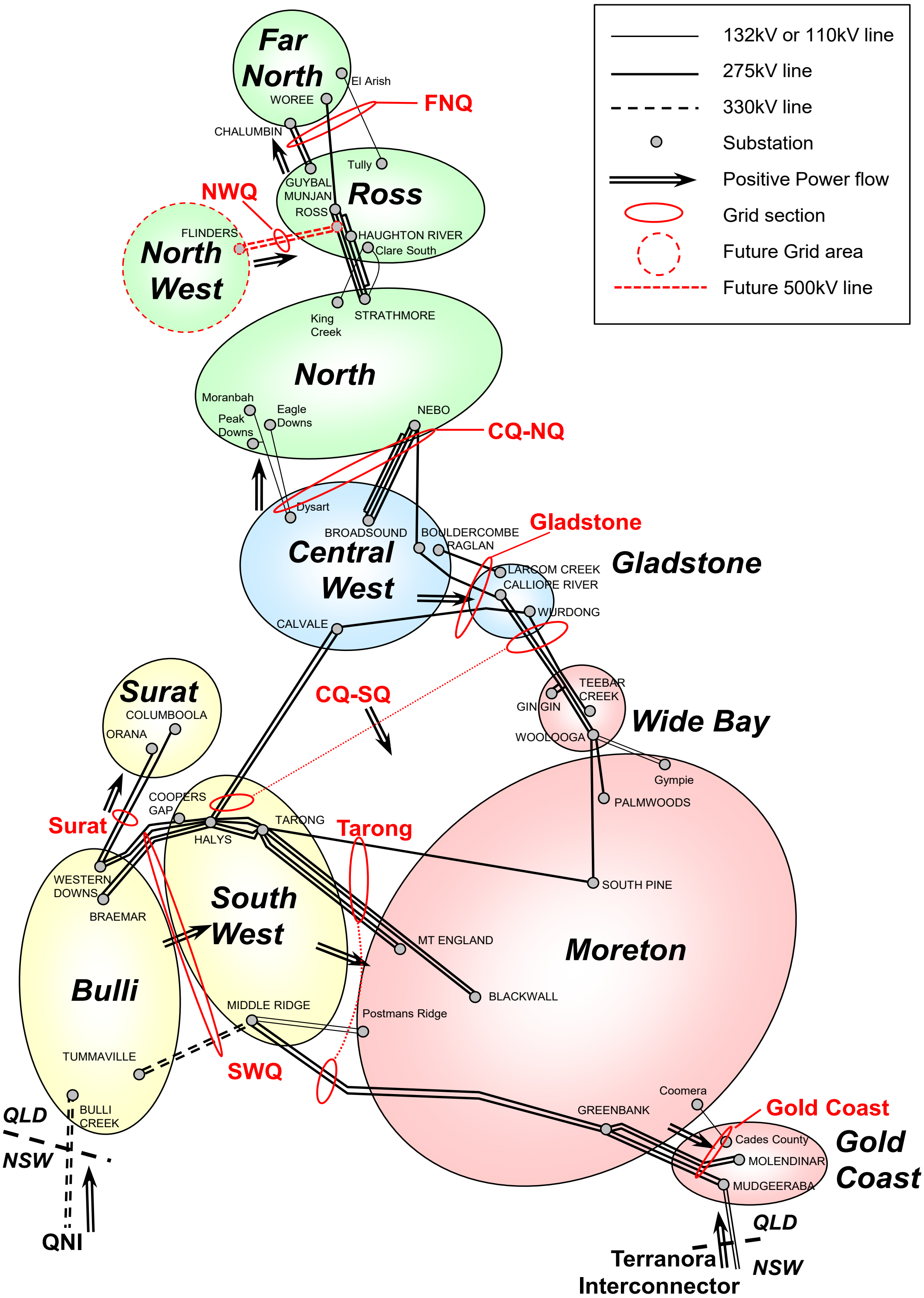
Table F.3 Zone Generation details *(continued)*

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
South West	Tarong	•						
	Tarong North	•						
	Oakey		•					
	Wambo (1)					•		
	Wambo 2 (1)					•		
	Coopers Gap					•		
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
	MacIntyre (1)					•		
	Chinchilla						•	
	Ulinda Park (1)						•	
	Western Downs						•	
Surat	Condamine		•					
	Columboola				•			
	Gangarri				•			
	Blue grass				•			
	Edenvale				•			
	Wandoan				•			
	Wandoan						•	

Note:

(1) Committed generation that is yet to begin production.

Figure F.1 Grid section legend



Appendix G Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland Region in its market dispatch systems.

These equations are continually under review to consider changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table G.1 Far North Queensland (FNQ) grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	597
Total MW generation at Mt Emerald Wind Farm	-0.55
Total MW generation at Kaban Wind Farm	-0.64
Total MW generation at Kareeya Power Station	-0.57
Total MW generation in Ross zone (1)	0.06
Total nominal MVAr of 132kV shunt capacitors on line within nominated Cairns area locations (2)	0.38
Total nominal MVAr of 275kV shunt reactors on line within nominated Cairns area locations (3)	-0.38
Total nominal MVAr of 132kV shunt reactors on line within nominated Chalumbin area locations (4)	-0.36
Total nominal MVAr of 275kV shunt reactors on line within nominated Chalumbin area locations (5)	-0.46
AEMO Constraint ID	Q^NIL_FNQ_8905

Notes:

(1) Ross generation term refers to summated active power generation at Mt Stuart, Townsville, Ross River Solar Farm, Sun Metals Solar Farm, Kidston Solar Farm, Hughenden Solar Farm, Clare Solar Farm, Haughton Solar Farm and Invicta Mill.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Cairns 132kV area comprise the following:

Innisfail 132kV	1 x 10MVAr
Edmonton 132kV	1 x 13MVAr
Woree 132kV	2 x 54MVAr

(3) The shunt reactor location, nominal sizes and quantities for the Cairns 275kV area comprise the following:

Woree 275kV	2 x 20.17MVAr

(4) The shunt reactor location, nominal size and quantities for the Chalumbin 132kV and below area comprise the following:

Chalumbin tertiary	1 x 20.2MVAr

(5) The shunt reactor location, nominal sizes and quantities for the Chalumbin 275kV area comprise the following:

Chalumbin 275kV	2 x 29.4MVAr, 1 x 30MVAr

Table G.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Feeder contingency	Townsville contingency (1)
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	1.000
Total MW generation at Mt Stuart	0.092	0.136
Number of Mt Stuart units on line [0 to 3]	22.447	14.513
Total MW northern VRE (2)	-1.00	-1.00
Total nominal MVAr shunt capacitors on line within nominated Ross area locations (3)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (4)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (5)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (6)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (7)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (8)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (9)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (9)	0.296	0.470
AEMO Constraint ID	Q^NIL_CN_FDR	Q^NIL_CN_GT

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) Northern VRE include:

Mt Emerald Wind Farm
Kaban Wind Farm
Ross River Solar Farm
Sun Metals Solar Farm
Haughton Solar Farm
Clare Solar Farm
Kidston Solar Farm
Kennedy Energy Park
Collinsville Solar Farm
Whitsunday Solar Farm
Hamilton Solar Farm
Hayman Solar Farm
Daydream Solar Farm
Rugby Run Solar Farm

(3) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 132kV	1 x 50MVAr
Townsville South 132kV	2 x 50MVAr
Dan Gleeson 66kV	2 x 24MVAr
Garbutt 66kV	2 x 15MVAr

(4) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 275kV	2 x 84MVAr, 2 x 29.4MVAr

(5) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Newlands 132kV	1 x 25MVAr
Clare South 132kV	1 x 20MVAr
Collinsville North 132kV	1 x 20MVAr

(6) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Strathmore 275kV	1 x 84MVAr

(7) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Moranbah 132kV	1 x 52MVAr
Pioneer Valley 132kV	1 x 30MVAr
Kemmis 132kV	1 x 30MVAr
Dysart 132kV	2 x 25MVAr
Alligator Creek 132kV	1 x 20MVAr
Mackay 33kV	2 x 15MVAr

(8) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Nebo 275kV	1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr

(9) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:

Nebo 275kV	2 x 120MVAr

The following table describes limit equations for the Inverter Based Resources (IBRs) in north Queensland. The Boolean AND operation is applied to the system conditions across a row, if the expression yields a True value then the maximum capacity quoted for the farm in question becomes an argument to a MAX function, if False then zero (0) becomes the argument to the MAX function. The maximum capacity is the result of the MAX function.

Table G.3 North Queensland system strength equations

System Conditions								Maximum Capacity (%)			
Number of Stanwell units online	Number of Stanwell + Callide (1) units online	Number of Gladstone units online	Number of CQ units online (2)	Number of Kareeya units online	NQ Load	Ross + FNQ Load	Haughton Synchronous Condenser Status	Haughton SF	Kaban WF	Mt Emerald WF	Other NQ Plants
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 350	> 150	OFF	0	40	40	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	OFF	0	25	25	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	ON	100	100	100	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	50	100	100	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	ON	100	100	100	100
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	OFF	50	50	80	80
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	ON	100	100	100	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	N/A	100	100	Wind = 100 Solar = N/A
AEMO Constraint ID								Q_NIL_STRGTH_HAUSF	Q_NIL_STRGTH_KBWF	Q_NIL_STRGTH_MEWF	Various (3)

Notes:

(1) Refers to the total number of Callide B and Callide C units online.

(2) Refers to the number of Gladstone, Stanwell and Callide units online.

(3) Q_NIL_STRGTH_CLRSF, Q_NIL_STRGTH_COLSF, Q_NIL_STRGTH_DAYSF, Q_NIL_STRGTH_HAMSF, Q_NIL_STRGTH_HAYSF, Q_NIL_STRGTH_KEP, Q_NIL_STRGTH_KIDSF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_RUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

Table G.4 Central to South Queensland grid section voltage stability equations

Measured variable	Coefficient
Constant term (intercept)	1,015
Total MW generation at Gladstone 275kV and 132kV	0.1407
Number of Gladstone 275kV units on line [2 to 4]	57.5992
Number of Gladstone 132kV units on line [1 to 2]	89.2898
Total MW generation at Callide B and Callide C	0.0901
Number of Callide B units on line [0 to 2]	29.8537
Number of Callide C units on line [0 to 2]	63.4098
Total MW generation in southern Queensland (1)	0.0650
Number of 90MVAr capacitor banks available at Boyne Island [0 to 2]	51.1534
Number of 50MVAr capacitor banks available at Boyne Island [0 to 1]	25.5767
Number of 120MVAr capacitor banks available at Wurdong [0 to 3]	52.2609
Number of 50MVAr capacitor banks available at Gin Gin [0 to 1]	31.5525
Number of 120MVAr capacitor banks available at Woolooga [0 to 1]	47.7050
Number of 50MVAr capacitor banks available at Woolooga [0 to 2]	22.9875
Number of 120MVAr capacitor banks available at Palmwoods [0 to 1]	30.7759
Number of 50MVAr capacitor banks available at Palmwoods [0 to 4]	14.2253
Number of 120MVAr capacitor banks available at South Pine [0 to 4]	9.0315
Number of 50MVAr capacitor banks available at South Pine [0 to 4]	3.2522
Equation lower limit	1,550
Equation upper limit	2,100 (2)
AEMO Constraint ID	Q^^NIL_CS, Q:NIL_CS

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank E, Wivenhoe, Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Western Downs Solar Farm, Columboola Solar Farm, Gangarri Solar Farm, Wandoan BESS, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Coopers Gap Wind Farm, Millmerran, Susan River Solar Farm, Childers Solar Farm, Columboola Solar Farm, Blue Grass Solar Farm, Western Downs Green Power Hub, Edenvale Solar Farm, Gangarri Solar Farm, Wandoan Solar Farm, Dulacca Wind Farm, Woolooga Energy Park, Chinchilla BESS and Terranora Interconnector and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between central and southern Queensland areas.

Table G.5 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW in Surat, Bulli and South West and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	-0.8625	-0.7945
Total MW generation at Wivenhoe and Swanbank E	-0.0517	0.0687
Active power transfer (MW) across Terranora Interconnector	-0.0808	-0.1287
Number of 200MVAr capacitor banks available (3)	7.6683	16.7396
Number of 120MVAr capacitor banks available (4)	4.6010	10.0438
Number of 50MVAr capacitor banks available (5)	1.9171	4.1849
Reactive to active demand percentage (6) (7)	-2.9964	-5.7927
Equation lower limit	3,200	3,200
AEMO Constraint ID	Q^^NIL_TR_CLHA	Q^^NIL_TR_TRBK

Notes:

(1) Equations 1 and 2 are offset by 100MW and 150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Surat, Bulli and South West generation term refers to summated active power generation at generation at Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Western Downs Green Power Hub, Columboola Solar Farm, Gangarri Solar Farm, Wandoan BESS, Wandoan Solar Farm, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Blue Grass Solar Farm, Edenvale Solar Farm, Coopers Gap Wind Farm, Dulacca Wind Farm, Millmerran, Chinchilla BESS, and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(3) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 17 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 37 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage = $\frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table G.6 Gold Coast grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	-137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	-20.0000
Active power transfer (MW) across Terranora Interconnector (3)	-0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	Q^NIL_GC

Notes:

(1) Moreton to Gold Coast demand ratio = $\frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently three capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 15 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 33 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix H Indicative short circuit currents

Tables H.1 to H.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations. Appendix H also shows the indicative System Strength Locational Factor (SSLF) calculated as per the AEMO System Strength Impact Assessment Guidelines[1]. An overview of system strength pricing can be found on Powerlink's website[2].

Indicative maximum short circuit currents

Tables H.1 to H.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2024/25, 2025/26 and 2026/27.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

The maximum short circuit currents were calculated using a system model:

- in which all generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with all model shunt elements removed.

The short circuit currents shown in tables H.1 to H.3 are based on generation shown in tables 7.1 and 7.2 (together with the more significant embedded non-scheduled generators) on the committed network development as forecast at the end of each calendar year. The tables also show the design rating of the Powerlink substation at each location. No assessment has been provided of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network; that is, all network elements are assumed to be in-service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create 'normally-open' point as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

Indicative minimum short circuit currents

Minimum short circuit currents are used to inform the capacity of the system to accommodate fluctuating loads and power electronic connected systems (including non-synchronous generators and static VAr compensators (SVC)). Minimum short circuit currents are also important in ensuring power quality and system stability standards are met and for ensuring the proper operation of protection systems.

Tables H.1 to H.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by taking the existing intact network and setting the synchronous generator dispatch to align with AEMO's assumptions for minimum three phase fault level as described in AEMO's 2023 System Strength Report. The short circuit current is calculated, using the sub-transient machine impedances, with the system intact and with individual outages of each significant network element.

The lowest minimum short circuit current which results from these outages is reported.

The short circuit currents are calculated using the same methodology as the AEMO's assumptions.However, AEMO report on the highest of the calculated minimum fault levels of these agreed minimum generator dispatches.

These minimum short circuit currents are indicative only. The system strength available to new non-synchronous generators can only be assessed by a Full Impact Assessment using electro magnetic transient (EMT-type) modelling techniques.

1 AEMO System Strength Impact Assessment Guideline.
2 Overview of system strength pricing.

Table H.1 Indicative short circuit currents – northern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Alan Sherriff	132	31.5	4.1	3.7	13.7	13.9	13.7	13.9	13.7	13.9	1.0346	Ross 275kV
Alligator Creek	132	31.5	3.1	1.8	4.4	5.9	4.5	5.9	4.5	5.9	1.1306	Ross 275kV
Aurumfield	275	40	1.2	1.1	3.7	4.7	3.7	4.7	3.7	4.7	1.1061	Ross 275kV
Bolingbroke	132	31.5	2.0	1.9	2.5	1.9	2.5	1.9	2.5	1.9	1.2139	Ross 275kV
Bowen North	132	31.5	2.1	0.7	3.0	3.2	3.0	3.2	3.0	3.2	1.1652	Ross 275kV
Cairns (2T)	132	31.5	3.1	0.5	6.8	8.9	6.8	8.9	6.8	8.9	1.0760	Ross 275kV
Cairns (3T)	132	31.5	3.1	0.5	6.8	8.9	6.8	8.9	6.8	8.9	1.0760	Ross 275kV
Cairns (4T)	132	31.5	3.1	0.5	6.8	9.0	6.8	9.0	6.8	9.0	1.0759	Ross 275kV
Cardwell	132	31.5	2.0	0.9	3.4	3.6	3.4	3.6	3.4	3.6	1.1442	Ross 275kV
Chalumbin	275	40	1.9	1.6	5.3	5.6	5.3	5.6	5.3	5.6	1.0453	Ross 275kV
Chalumbin	132	31.5	3.4	2.7	7.5	8.5	7.5	8.5	7.5	8.5	1.0790	Ross 275kV
Clare South	132	31.5	3.1	2.3	6.8	6.9	6.8	6.9	6.8	6.9	1.0898	Ross 275kV
Collinsville North	132	31.5	5.2	4.5	11.5	11.9	11.6	11.9	11.6	11.9	1.0446	Ross 275kV
Coppabella	132	31.5	2.2	1.5	3.0	3.4	3.0	3.4	3.0	3.4	1.1885	Ross 275kV
Crush Creek	275	40	3.5	3.0	10.8	11.9	10.8	12.0	10.9	12.0	1.0203	Ross 275kV
Dan Gleeson (1T)	132	31.5	4.0	3.7	13.0	13.3	13.0	13.3	13.1	13.3	1.0350	Ross 275kV
Dan Gleeson (2T)	132	31.5	4.0	3.7	13.0	13.4	13.0	13.4	13.1	13.4	1.0350	Ross 275kV
Edmonton	132	31.5	2.9	0.9	6.1	7.3	6.1	7.3	6.1	7.3	1.0835	Ross 275kV
Eagle Downs	132	31.5	3.0	1.5	4.6	4.4	4.6	4.4	4.6	4.4	1.1297	Lilyvale 132kV
El Arish	132	31.5	2.3	1.0	3.8	4.6	3.8	4.6	3.8	4.6	1.1213	Ross 275kV

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents						SSLF	Ref Node
					2024/25		2025/26		2026/27			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Garbutt	132	31.5	3.8	1.7	11.2	11.0	11.2	11.1	11.2	11.1	1.0427	Ross 275kV
Greenland	132	31.5	3.4	2.1	5.5	5.1	5.5	5.1	5.5	5.1	1.1170	Ross 275kV
Goonyella Riverside	132	31.5	3.5	3.0	6.0	5.5	6.0	5.4	6.0	5.4	1.1096	Ross 275kV
Guybal Munjan	275	40	2.2	1.9	6.6	5.3	6.6	5.3	6.6	5.3	1.0266	Ross 275kV
Haughton River	275	40	2.7	2.0	8.4	8.6	8.5	8.6	8.5	8.6	1.0132	Ross 275kV
Ingham South	132	31.5	1.9	1.1	3.5	3.5	3.5	3.5	3.5	3.5	1.1542	Ross 275kV
Innisfail	132	31.5	2.1	1.3	3.3	3.9	3.3	3.9	3.3	3.9	1.1435	Ross 275kV
Invicta	132	31.5	2.5	2.4	5.3	4.8	5.3	4.8	5.3	4.8	1.1103	Ross 275kV
Kamerunga (1T)	132	31.5	2.6	0.6	5.0	5.8	5.0	5.8	5.0	5.8	1.1061	Ross 275kV
Kamerunga (2T)	132	31.5	2.6	0.6	5.0	5.9	5.0	5.9	5.0	5.9	1.1061	Ross 275kV
Kareeya	132	31.5	3.2	2.4	6.2	6.9	6.2	6.9	6.2	6.9	1.0957	Ross 275kV
Kemmis	132	31.5	3.9	1.6	6.1	6.6	6.1	6.7	6.2	6.7	1.1018	Ross 275kV
King Creek	132	31.5	3.1	1.3	5.4	4.4	5.4	4.4	5.4	4.4	1.0944	Ross 275kV
Lake Ross	132	31.5	4.6	4.2	18.2	20.1	18.2	20.2	18.3	20.2	1.0215	Ross 275kV
Landers Creek	132	31.5	2.9	1.4	-	-	-	-	5.7	5.0	1.1007	Ross 275kV
Mackay	132	31.5	3.4	2.9	5.1	6.1	5.1	6.1	5.1	6.1	1.1194	Ross 275kV
Mackay Ports	132	31.5	2.6	1.6	3.5	4.1	3.5	4.1	3.5	4.1	1.1616	Ross 275kV
Mindi	132	31.5	3.5	3.3	4.9	3.7	4.9	3.7	4.9	3.7	1.1171	Ross 275kV
Moranbah	132	31.5	4.0	3.3	8.0	9.5	8.0	9.6	8.0	9.6	1.0983	Ross 275kV
Moranbah Plains	132	31.5	2.7	2.3	4.4	4.8	4.4	4.8	4.4	4.8	1.1545	Ross 275kV
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.3	5.7	5.3	1.1221	Ross 275kV

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Mt Mclaren	132	31.5	1.6	1.4	2.1	2.3	2.1	2.3	2.1	2.3	1.2718	Ross 275kV
Nebo	275	40	4.6	4.0	11.9	11.9	12.1	12.2	12.3	12.5	1.0374	Ross 275kV
Nebo	132	31.5	7.1	6.2	14.2	16.2	14.3	16.4	14.4	16.5	1.0529	Ross 275kV
Newlands	132	31.5	2.5	1.3	3.6	4.0	3.6	4.0	3.6	4.0	1.1498	Ross 275kV
North Goonyella	132	31.5	2.9	2.5	4.5	3.8	4.5	3.7	4.5	3.7	1.1338	Ross 275kV
Oonooie	132	31.5	2.4	1.5	3.1	3.7	3.1	3.7	3.1	3.7	1.1776	Ross 275kV
Peak Downs	132	31.5	2.8	2.1	4.2	3.7	4.2	3.7	4.2	3.7	1.1364	Lilyvale 132kV
Pioneer Valley	132	31.5	4.1	3.6	6.6	7.5	6.6	7.5	6.7	7.6	1.0970	Ross 275kV
Proserpine	132	31.5	2.5	1.8	3.5	4.1	3.5	4.1	3.5	4.1	1.1388	Ross 275kV
Ross	275	40	2.8	2.4	10.2	11.2	10.2	11.2	10.3	11.2	1.0000	Ross 275kV
Ross	132	31.5	4.7	4.2	18.8	21.0	18.8	21.0	18.9	21.0	1.0206	Ross 275kV
Springlands	132	31.5	5.5	4.6	12.7	14.3	12.8	14.4	12.8	14.4	1.0399	Ross 275kV
Stony Creek	132	31.5	2.7	1.2	3.8	3.7	3.8	3.7	3.8	3.7	1.1354	Ross 275kV
Strathmore	275	40	3.5	3.0	10.9	12.1	11.0	12.2	11.0	12.2	1.0200	Ross 275kV
Strathmore	132	31.5	5.6	4.7	13.2	15.3	13.2	15.3	13.3	15.3	1.0385	Ross 275kV
Townsville East	132	31.5	3.8	1.6	13.0	12.6	13.0	12.6	13.0	12.6	1.0435	Ross 275kV
Townsville South	132	31.5	4.1	3.8	17.5	21.0	17.6	21.0	17.6	21.0	1.0337	Ross 275kV
Townsville GT PS	132	31.5	3.4	2.4	10.1	10.7	10.1	10.7	10.1	10.7	1.0560	Ross 275kV
Tully	132	31.5	2.8	1.5	5.1	5.9	5.0	5.7	5.0	5.7	1.0892	Ross 275kV
Tully South	275	40	1.7	1.2	3.9	3.8	3.9	3.8	3.9	3.8	1.0506	Ross 275kV

Table H.1 Indicative short circuit currents – northern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Tumoulin	275	40	1.8	1.2	4.5	5.2	4.5	5.2	4.5	5.2	1.0540	Ross 275kV
Turkinje	132	31.5	1.8	1.2	2.8	3.1	2.8	3.1	2.8	3.1	1.1933	Ross 275kV
Walkamin	275	40	1.7	1.4	4.3	4.9	4.3	4.9	4.3	4.9	1.0575	Ross 275kV
Wandoo	132	31.5	3.3	3.1	4.6	3.3	4.6	3.3	4.6	3.3	1.1244	Ross 275kV
Woree	275	40	1.8	1.5	4.5	5.4	4.5	5.4	4.6	5.4	1.0531	Ross 275kV
Woree	132	31.5	3.2	2.7	7.1	9.6	7.1	9.6	7.1	9.6	1.0730	Ross 275kV
Wotonga	132	31.5	3.5	1.7	6.0	7.0	6.0	7.0	6.0	7.0	1.1137	Ross 275kV
Yabulu South	132	31.5	3.7	3.2	11.3	10.9	11.3	10.9	11.3	10.9	1.0448	Ross 275kV

Table H.2 Indicative short circuit currents – central Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents						SSLF	Ref Node
					2024/25		2025/26		2026/27			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Baralaba	132	31.5	3.4	2.1	4.4	3.8	4.4	3.8	4.4	3.8	1.1421	Lilyvale 132kV
Biloela	132	31.5	6.1	3.5	8.2	8.4	8.2	8.4	8.2	8.4	1.0889	Gin Gin 275kV
Blackwater	132	31.5	4.0	3.3	6.0	7.1	6.0	7.2	6.0	7.2	1.0480	Lilyvale 132kV
Bluff	132	31.5	2.6	2.3	3.5	4.3	3.5	4.3	3.5	4.3	1.1057	Lilyvale 132kV
Bouldercombe	275	40.0	10.1	8.6	21.6	20.6	22.1	21.1	22.2	21.1	1.0375	Gin Gin 275kV
Bouldercombe	132	31.5	10.2	6.3	15.0	17.2	15.1	17.3	15.1	17.3	1.0595	Gin Gin 275kV
Broadsound	275	40.0	6.0	4.9	15.4	16.1	16.1	19.4	16.5	19.8	1.0434	Lilyvale 132kV
Bundoora	132	31.5	5.2	4.4	9.5	9.2	9.5	9.2	9.5	9.2	1.0120	Lilyvale 132kV
Callemondah	132	31.5	16.0	6.7	22.2	24.8	22.5	25.1	22.5	25.1	1.0397	Gin Gin 275kV
Calliope River	275	40.0	10.3	8.7	21.3	24.3	22.3	25.7	22.5	25.8	1.0231	Gin Gin 275kV
Calliope River	132	40.0	17.5	14.2	24.9	30.0	25.3	30.4	25.3	30.5	1.0372	Gin Gin 275kV
Calvale	275	40.0	10.1	8.3	24.2	26.5	24.4	26.7	24.4	26.7	1.0379	Gin Gin 275kV
Calvale (1T)	132	31.5	6.6	2.8	9.0	9.8	9.0	9.8	9.0	9.8	1.0839	Gin Gin 275kV
Calvale (2T)	132	31.5	6.8	3.1	8.6	9.4	8.6	9.4	8.6	9.4	1.0822	Gin Gin 275kV
Duaringa	132	31.5	1.9	1.6	2.3	2.9	2.3	2.9	2.3	2.9	1.2140	Lilyvale 132kV
Dysart	132	31.5	3.2	1.9	4.8	5.4	4.8	5.4	4.8	5.4	1.1041	Lilyvale 132kV
Egans Hill	132	31.5	6.4	1.6	8.5	8.3	8.5	8.3	8.5	8.3	1.0851	Gin Gin 275kV
Gladstone PS	275	40.0	9.9	8.4	19.8	22.0	20.7	23.2	20.8	23.3	1.0241	Gin Gin 275kV
Gladstone PS	132	40.0	16.0	12.6	21.9	25.1	22.2	25.4	22.2	25.4	1.0411	Gin Gin 275kV
Gladstone South	132	31.5	12.3	9.6	16.3	17.3	16.4	17.4	16.5	17.4	1.0479	Gin Gin 275kV
Glencoe	275	40.0	4.4	2.3	-	-	-	-	9.4	9.7	1.0568	Lilyvale 132kV

Table H.2 Indicative short circuit currents – central Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents						SSLF	Ref Node
					2024/25		2025/26		2026/27			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Grantleigh	132	31.5	2.3	2.0	2.7	2.8	2.7	2.8	2.7	2.8	1.2084	Gin Gin 275kV
Gregory	132	31.5	5.7	4.7	10.5	11.8	10.6	11.9	10.7	11.9	1.0027	Lilyvale 132kV
Larcom Creek	275	40.0	9.2	3.3	15.7	15.9	17.0	19.2	17.1	19.2	1.0296	Gin Gin 275kV
Larcom Creek	132	31.5	7.9	4.2	12.4	13.9	12.6	14.4	12.6	14.4	1.0597	Gin Gin 275kV
Lilyvale	275	40.0	3.5	2.6	6.7	6.5	6.8	6.7	6.9	6.7	1.0216	Lilyvale 132kV
Lilyvale	132	31.5	5.9	4.8	11.2	12.9	11.3	13.0	11.3	13.1	1.0000	Lilyvale 132kV
Moura	132	31.5	3.2	1.5	4.4	5.4	4.4	5.4	4.4	5.4	1.1545	Gin Gin 275kV
Norwich Park	132	31.5	2.7	2.5	3.7	2.7	3.7	2.7	3.7	2.7	1.1087	Lilyvale 132kV
Pandoin	132	31.5	5.4	1.2	7.0	6.1	7.1	6.1	7.1	6.1	1.0971	Gin Gin 275kV
Raglan	275	40.0	7.7	4.3	12.2	10.6	12.6	11.3	12.6	11.4	1.0375	Gin Gin 275kV
Rockhampton (1T)	132	31.5	5.1	1.8	6.5	6.4	6.6	6.4	6.6	6.4	1.1022	Gin Gin 275kV
Rockhampton (5T)	132	31.5	5.0	1.8	6.3	6.2	6.3	6.2	6.4	6.2	1.1047	Gin Gin 275kV
Stanwell	275	40.0	10.8	9.0	24.7	25.9	25.2	26.5	25.4	26.6	1.0381	Gin Gin 275kV
Stanwell	132	31.5	4.8	3.7	6.0	6.5	6.0	6.5	6.0	6.5	1.1085	Gin Gin 275kV
Wurdong	275	40.0	9.4	6.4	17.0	16.9	17.5	17.3	17.5	17.3	1.0267	Gin Gin 275kV
Wycarbah	132	31.5	3.7	3.0	4.6	5.4	4.6	5.4	4.6	5.4	1.1346	Gin Gin 275kV
Yarwun	132	31.5	7.9	4.5	12.9	14.9	13.2	15.2	13.2	15.2	1.0617	Gin Gin 275kV

Table H.3 Indicative short circuit currents – southern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Abermain	275	40	8.0	6.3	19.1	19.4	19.2	19.4	19.2	19.4	1.0054	Greenbank 275kV
Abermain	110	31.5	12.9	10.4	21.8	24.7	21.9	24.8	21.9	24.8	1.0209	Greenbank 275kV
Algester	110	31.5	12.8	11.5	21.4	21.1	21.5	21.1	21.5	21.1	1.0207	Greenbank 275kV
Ashgrove West	110	31.5	12.1	9.2	19.4	20.2	19.4	20.4	19.4	20.4	1.0258	Greenbank 275kV
Banana Bridge	275	40	7.4	5.0	27.2	28.4	27.6	29.2	27.6	29.2	1.0007	Western Downs 275kV
Belmont	275	40	7.8	7.1	17.8	18.4	17.9	18.5	17.9	18.5	1.0051	Greenbank 275kV
Belmont	110	40	15.3	14.2	28.5	35.2	28.6	35.2	28.6	35.2	1.0128	Greenbank 275kV
Blackstone	275	40	8.6	7.8	22.6	24.7	22.8	24.8	22.8	24.8	1.0017	Greenbank 275kV
Blackstone	110	40	14.5	13.3	26.0	28.4	26.0	28.4	26.0	28.4	1.0160	Greenbank 275kV
Blackwall	275	40	9.9	8.3	23.7	25.2	23.9	25.3	23.9	25.3	1.0048	Greenbank 275kV
Blythdale	132	31.5	3.1	2.3	4.3	5.3	4.3	5.3	4.3	5.3	1.1113	Western Downs 275kV
Braemar	330	50	6.9	5.6	25.5	27.2	25.6	27.3	25.6	27.3	1.0086	Western Downs 275kV
Braemar (1T)	275	50	9.9	5.2	28.3	32.5	28.4	32.5	28.4	32.5	1.0118	Western Downs 275kV
Braemar (2T)	275	50	7.8	4.5	30.1	32.7	30.3	32.8	30.3	32.8	1.0048	Western Downs 275kV
Bulli Creek	330	50	6.7	6.1	20.3	15.8	20.3	15.8	20.3	15.8	1.0173	Western Downs 275kV
Bulli Creek	132	31.5	3.0	3.0	4.1	4.6	4.1	4.6	4.1	4.6	1.1368	Western Downs 275kV
Bundamba	110	31.5	11.1	7.6	17.5	16.7	17.5	16.7	17.5	16.7	1.0275	Greenbank 275kV
Cameby	132	31.5	4.7	3.6	9.1	8.6	9.1	8.6	9.1	8.6	1.0659	Western Downs 275kV

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents						SSLF	Ref Node
					2024/25		2025/26		2026/27			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Chinchilla	132	31.5	3.8	3.0	6.5	7.9	6.5	7.9	6.5	7.9	1.0873	Western Downs 275kV
Clifford Creek	132	31.5	4.0	3.3	5.9	5.3	6.0	5.3	6.0	5.3	1.0810	Western Downs 275kV
Columboola	275	40	5.2	3.9	14.3	13.4	14.3	13.4	14.3	13.4	1.0125	Western Downs 275kV
Columboola	132	31.5	6.7	4.9	17.3	20.4	17.3	20.4	17.3	20.4	1.0370	Western Downs 275kV
Condabri Central	132	31.5	4.9	3.9	9.2	6.8	9.2	6.8	9.2	6.8	1.0609	Western Downs 275kV
Condabri North	132	31.5	6.1	4.5	13.8	12.9	13.8	12.9	13.8	12.9	1.0438	Western Downs 275kV
Condabri South	132	31.5	4.0	3.3	6.7	4.5	6.7	4.5	6.7	4.5	1.0804	Western Downs 275kV
Coopers Gap	275	40	8.0	3.1	18.5	18.2	18.5	18.2	18.5	18.2	1.0158	Western Downs 275kV
Diamondy	275	40	7.9	6.7	15.1	11.5	15.1	11.5	15.1	11.5	1.0222	Western Downs 275kV
Dinoun South	132	31.5	4.4	3.6	6.8	7.1	6.8	7.1	6.8	7.1	1.0707	Western Downs 275kV
Eurombah	275	40	2.7	1.2	4.7	4.8	4.7	4.8	4.7	4.8	1.0491	Western Downs 275kV
Eurombah	132	31.5	4.6	3.4	7.3	8.9	7.3	8.9	7.3	8.9	1.0672	Western Downs 275kV
Fairview	132	31.5	3.0	2.5	4.1	5.2	4.1	5.2	4.1	5.2	1.1177	Western Downs 275kV
Fairview South	132	31.5	3.7	2.9	5.4	6.8	5.4	6.8	5.4	6.8	1.0895	Western Downs 275kV
Gin Gin	275	40	6.1	4.3	9.5	9.0	9.7	9.2	10.0	9.3	1.0000	Gin Gin 275kV
Gin Gin	132	31.5	8.6	6.7	12.4	13.6	12.6	13.8	13.1	14.3	1.0185	Gin Gin 275kV

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Goodna	275	40	7.7	5.5	16.9	16.4	17.0	16.5	17.0	16.5	1.0078	Greenbank 275kV
Goodna	110	40	14.6	12.8	26.0	27.9	26.1	28.0	26.1	28.0	1.0164	Greenbank 275kV
Greenbank	275	50	8.4	7.7	22.0	24.6	22.1	24.7	22.1	24.7	1.0000	Greenbank 275kV
Halys	275	50	12.2	9.6	35.2	30.7	35.3	30.7	35.3	30.7	1.0129	Western Downs 275kV
Kumbarilla Park	275	40	6.6	1.7	17.2	16.4	17.2	16.4	17.2	16.4	1.0173	Western Downs 275kV
Kumbarilla Park	132	31.5	8.3	5.5	13.3	15.3	13.3	15.3	13.3	15.3	1.0385	Western Downs 275kV
Loganlea	275	40	7.2	6.0	15.7	15.9	15.7	16.0	15.7	16.0	1.0059	Greenbank 275kV
Loganlea	110	40	13.3	11.9	23.2	27.8	23.2	27.8	23.3	27.8	1.0170	Greenbank 275kV
Middle Ridge (4T)	330	50	5.7	3.5	14.0	13.3	14.0	13.3	14.0	13.3	1.0244	Western Downs 275kV
Middle Ridge (5T)	330	50	5.8	3.5	14.4	13.7	14.4	13.7	14.4	13.7	1.0240	Western Downs 275kV
Middle Ridge	275	40	7.6	6.7	20.0	19.6	20.0	19.7	20.0	19.7	1.0136	Greenbank 275kV
Middle Ridge	110	40	10.6	8.8	21.9	25.7	21.9	25.7	21.9	25.7	1.0350	Greenbank 275kV
Millmerran	330	50	6.3	5.8	21.6	23.4	21.6	23.4	21.6	23.4	1.0200	Western Downs 275kV
Miss	330	50	5.2	4.4	15.3	17.3	15.3	17.2	15.3	17.2	1.0265	Western Downs 275kV
Molendinar (1T)	275	40	5.0	2.1	8.4	8.2	8.5	8.2	8.5	8.2	1.0175	Greenbank 275kV
Molendinar (2T)	275	40	5.0	2.1	8.4	8.2	8.4	8.2	8.4	8.2	1.0176	Greenbank 275kV
Molendinar	110	31.5	11.8	10.2	19.7	24.9	19.7	24.8	19.7	24.8	1.0199	Greenbank 275kV
Mt England	275	40	9.6	8.1	23.9	23.7	24.1	23.8	24.1	23.8	1.0072	Greenbank 275kV
Mudgeeraba	275	40	5.4	4.3	9.5	8.7	9.5	8.7	9.5	8.7	1.0143	Greenbank 275kV

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents						SSLF	Ref Node
					2024/25		2025/26		2026/27			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Mudgeeraba	110	31.5	11.0	10.0	17.7	21.3	17.7	21.4	17.7	21.4	1.0233	Greenbank 275kV
Murarrie (1T)	275	40	6.8	2.3	13.7	13.5	13.7	13.5	13.7	13.5	1.0092	Greenbank 275kV
Murarrie (2T)	275	40	6.8	2.3	13.7	13.6	13.7	13.6	13.7	13.6	1.0092	Greenbank 275kV
Murarrie	110	40	13.8	12.7	24.3	29.2	24.4	29.3	24.4	29.3	1.0164	Greenbank 275kV
Oakey	110	31.5	5.1	3.7	11.5	12.5	11.5	12.5	11.5	12.5	1.0882	Greenbank 275kV
Oakey Gt	110	31.5	4.9	1.3	10.3	10.1	10.3	10.1	10.3	10.1	1.0935	Greenbank 275kV
Orana	275	40	6.0	3.0	16.9	16.3	17.0	16.4	17.0	16.4	1.0073	Western Downs 275kV
Palmwoods	275	40	5.6	3.4	8.8	9.2	9.0	9.3	9.0	9.3	1.0299	Greenbank 275kV
Palmwoods	132	31.5	9.1	6.8	13.4	16.2	13.7	16.5	13.8	16.5	1.0403	Greenbank 275kV
Palmwoods (7T)	110	31.5	5.7	2.6	7.3	7.6	7.3	7.6	7.3	7.6	1.0834	Greenbank 275kV
Palmwoods (8T)	110	31.5	5.7	2.6	7.3	7.6	7.3	7.6	7.3	7.6	1.0834	Greenbank 275kV
Redbank Plains	110	31.5	12.9	9.5	21.7	20.9	21.8	20.9	21.8	20.9	1.0207	Greenbank 275kV
Richlands	110	31.5	13.2	10.9	22.3	22.9	22.3	23.0	22.3	23.0	1.0202	Greenbank 275kV
Rocklea (1T)	275	40	6.9	2.3	13.6	12.5	13.7	12.6	13.7	12.6	1.0122	Greenbank 275kV
Rocklea (2T)	275	40	5.4	2.3	8.9	8.5	9.0	8.6	9.0	8.6	1.0235	Greenbank 275kV
Rocklea	110	40	14.5	12.8	25.5	29.2	25.6	29.4	25.6	29.5	1.0180	Greenbank 275kV
Runcorn	110	31.5	11.8	8.6	19.1	19.4	19.1	19.4	19.1	19.4	1.0237	Greenbank 275kV
South Pine	275	40	9.3	7.9	19.7	22.1	20.0	22.3	20.0	22.3	1.0099	Greenbank 275kV
South Pine (East)	110	40	13.5	11.5	21.9	28.0	22.1	28.1	22.1	28.2	1.0253	Greenbank 275kV
South Pine (West)	110	40	12.8	10.1	20.8	23.8	20.8	24.0	20.8	24.0	1.0249	Greenbank 275kV

Table H.3 Indicative short circuit currents – southern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal 3 phase fault level (kA)	Indicative minimum post-contingent 3 phase fault level (kA)	Indicative maximum short circuit currents 2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	2026/27 3 phase (kA)	2026/27 L – G (kA)	SSLF	Ref Node
Sumner	110	31.5	12.7	9.1	21.0	20.4	21.1	21.0	21.1	21.0	1.0226	Greenbank 275kV
Swanbank E	275	40	8.5	7.2	22.3	24.2	22.4	24.3	22.4	24.3	1.0017	Greenbank 275kV
Tangkam	110	31.5	6.0	4.2	13.7	12.5	13.7	12.5	13.7	12.5	1.0729	Greenbank 275kV
Tarong	275	50	11.8	9.4	36.7	39.1	36.9	39.1	36.9	39.1	1.0111	Greenbank 275kV
Tarong	66	31.5	12.3	7.0	15.5	16.6	15.5	16.6	15.5	16.6	1.0642	Greenbank 275kV
Teebar Creek	275	40	4.9	2.3	7.4	7.2	7.6	7.3	7.7	7.4	1.0319	Gin Gin 275kV
Teebar Creek	132	31.5	7.2	4.5	10.0	11.1	10.2	11.2	10.3	11.3	1.0469	Gin Gin 275kV
Tennyson	110	31.5	10.7	1.8	16.4	16.5	16.5	16.6	16.5	16.6	1.0309	Greenbank 275kV
Tummaville	330	50	6.1	5.7	20.2	20.7	20.2	20.7	20.2	20.7	1.0210	Western Downs 275kV
Upper Kedron	110	40	13.1	11.3	21.6	18.9	21.7	19.5	21.7	19.5	1.0227	Greenbank 275kV
Wandoan South	275	40	3.8	3.0	8.3	9.4	8.3	9.4	8.3	9.4	1.0272	Western Downs 275kV
Wandoan South	132	31.5	5.5	4.2	10.3	13.2	10.3	13.2	10.3	13.2	1.0512	Western Downs 275kV
West Darra	110	40	14.4	13.2	25.4	24.1	25.5	24.4	25.5	24.4	1.0173	Greenbank 275kV
Western Downs	275	50	7.6	5.1	29.5	31.6	30.0	32.7	30.0	32.7	1.0000	Western Downs 275kV
Woolooga	275	40	6.4	5.4	10.6	12.1	11.3	13.0	11.4	13.1	1.0223	Gin Gin 275kV
Woolooga	132	31.5	9.0	7.1	14.3	17.7	16.2	20.5	16.3	20.6	1.0394	Gin Gin 275kV
Yuleba North	275	40	3.3	2.7	6.5	7.1	6.5	7.1	6.5	7.1	1.0349	Western Downs 275kV
Yuleba North	132	31.5	5.0	3.9	8.2	10.0	8.2	10.0	8.2	10.0	1.0590	Western Downs 275kV

Appendix I Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
AI	Artificial Intelligence
ARR	Asset Reinvestment Review
BSL	Boyne Smelters Limited
BESS	Battery Energy Storage System
CAA	Connection and Access Agreement
CBD	Central Business District
CER	Consumer Energy Resources
CQ	Central Queensland
CQ-SQ	Central Queensland to South Queensland
CQ-NQ	Central Queensland to North Queensland
CVTs	Capacitive voltage transformers
DCA	Dedicated Connection Assets
DEC	Department of Energy and Climate
DER	Distributed Energy Resources
DNA	Designated Network Assts
DNSP	Distribution Network Service Provider
DSM	Demand side management
EAP	Energy Advisory Panel
ECMC	Energy and Climate Ministerial Council
ECS	Emergency Control Scheme
EFCS	Emergency Frequency Control Schemes
EJPC	Executive Joint Planning Committee
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
EUSE	expected unserved energy
FIA	Full Impact Assessment
FNQ	Far North Queensland
FRG	Forecasting Reference Group
GPS	Gladstone Power Station
GPSRR	General Power System Risk Review
HTC	High Temperature Conductor
HV	High Voltage
IBR	Inverter-based Resources
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
JPC	Joint Planning Committee
kA	Kiloampere
kV	Kilovolts
LEIP	Lansdown Eco Industrial Precinct
LTTW	Lightning Trip Time Window
MLF	Marginal Loss Factors
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
MWs	Megawatt seconds
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNESR	Non-network Engagement Stakeholder Register
NSCAS	Nework Support and Control Ancillary Service
NSP	Network Service Providers

Appendix I Glossary *(continued)*

NSW	New South Wales
NQ	North Queensland
NWMP	North West Mineral Province
OCG	Office of the Coordinator-General
ODP	Optimal Development Path
OFGS	Over Frequency Generation Shedding
OIP	Optimal Infrastructure Pathway
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PHES	Pumped Hydro Energy Storage
PoE	Probability of Exceedance
PS	Power Station
PSCR	Project Specification Consultation Report
PSMRG	Power System Modelling Reference Group
PTI	Priority transmission investment
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
QAL	Queensland Alumina Limited
QEJP	Queensland Energy and Jobs Plan
QHES	Queensland Household Energy Survey
QNI	Queensland to New South Wales Interconnector
QRET	Queensland Renewable Energy Target
RBA	Reserve Bank of Australia
RDB	REZ Delivery Body
RET	Renewable Energy Targets
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RMP	REZ Management Plans
RSAS	Reliability and Security Ancillary Service
RWG	Regulatory Working Group
SQ	Southern Queensland
SEQ	South East Queensland
SPS	Special Protection Scheme
SSIAG	System Strength Assessment Guidelines
SSLF	System Strength Locational Factor
SSSP	System Strength Service Provider
SSUP	System Strength Unit Prices
SVC	Static VAr Compensator
SWQ	South West Queensland
TAPR	Transmission Annual Planning Report
TEEP	Transmission Easement Engagement Process
TGCP	TAPR Guideline Connection Point
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable renewable energy
WAMPAC	Wide area monitoring protection and control