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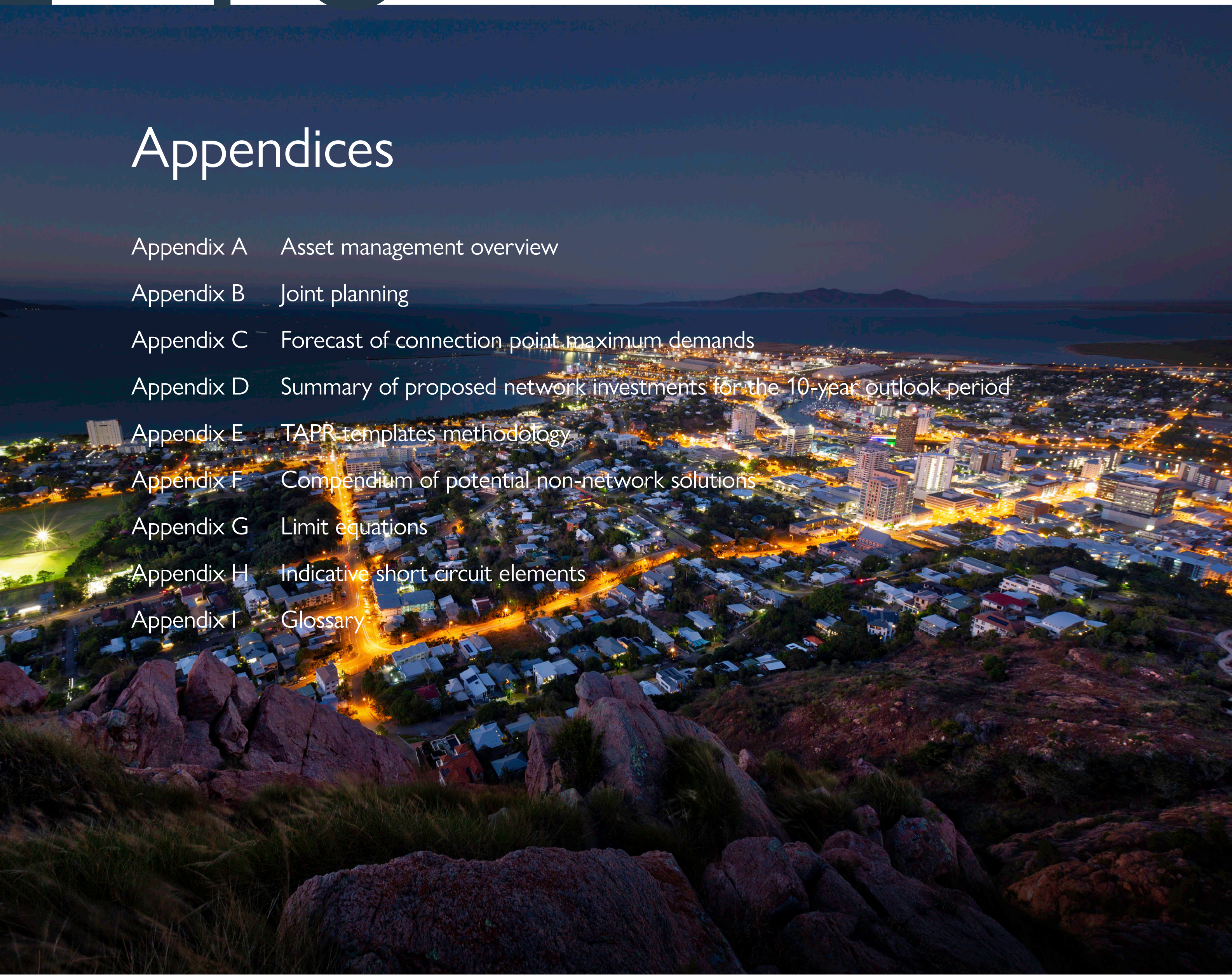


Appendices

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

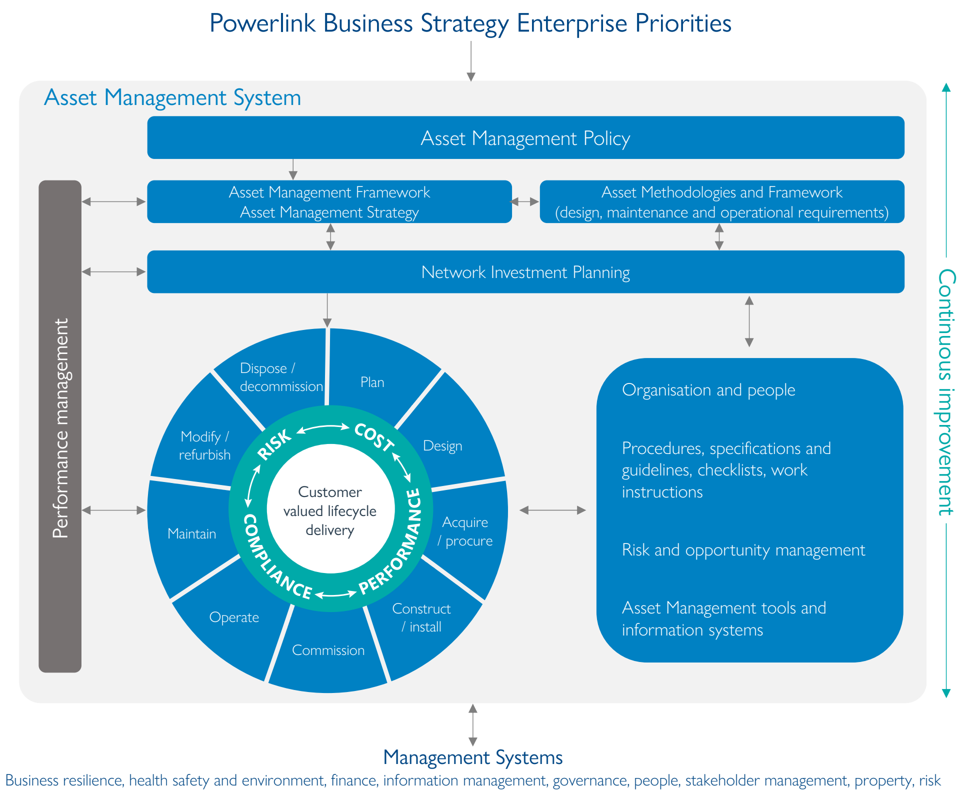
Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver safe, cost effective, reliable and sustainable services.

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 long-term 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 ongoing 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.

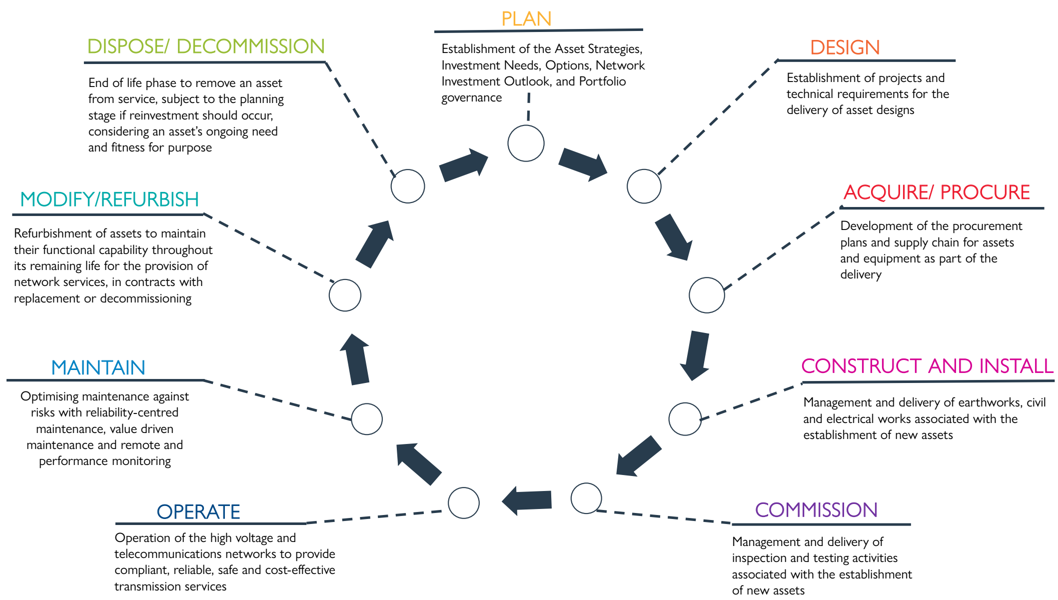
All asset management related activities are undertaken by applying relevant procedures, specifications and guidelines for delivering each stage of an asset life cycle activity.

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 ongoing 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 2022 System Security Reports
- Network Support and Control Ancillary Service (NSCAS)
- System Strength and Inertia requirements
- AEMO's 2024 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 is working closely with AEMO to support the development of the 2024 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 2022 and 2023 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. Powerlink and the Department of Energy and Public Works (DEPW) 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 has resulted in the Borumba PHES and CopperString 2032 projects being modelled as anticipated projects in the 2024 ISP.

In addition, as requested in AEMO's 2022 ISP (published in July 2022) Powerlink also prepared Preparatory Activity reports for expansion of the Darling Downs Renewable Energy Zone (REZ) expansion Stage 1 and for a further interconnector upgrade between Queensland and New South Wales (refer to Section 6.15). This involvement was critical to ensure the best possible jurisdictional inputs are provided to the ISP process in the long-term interests of customers.

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 2024 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 2022 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 for 2022. 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 2022 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 sections 4.3 and 6.8.1).

The 2022 System Security Report also 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 (refer to sections 4.5 and 6.8.2).

AEMO also published an immediate Network Support and Ancillary Service (NSCAS) gap of approximately 120MVAr reactive power absorption in Southern Queensland increasing in size to 250MVAr by 2026. Powerlink has recently published a Project Assessment Conclusions (PACR) to manage voltages in South East Queensland (SEQ) to address this NSCAS gap (refer to sections 6.5.1 and 9.5).

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

AEMO published the General Power System Risk Review (GPSRR) in July 2023.

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.

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.

1 System Security Market Frameworks Review. System Strength Requirements Methodology - September 2002 (latest version)
2 Network Support and Control Ancillary Service Description and Quantity Procedure.

Outcomes

The Final 2023 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. If a scheme is found viable, AEMO recommends this scheme be commissioned no later than June 2025.
- Each jurisdiction develop and coordinate emergency reserve and system security contingency plans, which can be implemented at short notice if required to address potential risk.
- All NSPs evaluate current and emerging capability gaps in operational capability, encompassing online tools, systems and training.
- 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 include:

- 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 QNIto 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 commencement of 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 safe and expeditious release of additional capacity.

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 2022 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
Kamerunga 132/22kV transformer replacement	Appendix D, Table D.1
Maintaining reliability of supply to Cairns northern beaches area	Section 6.9.1
Maintaining reliability of supply and addressing condition risks at Ingham South	Section 6.9.2
Maintaining reliability of supply to Gladstone South	Section 6.10.2
Maintain reliability of supply to the Brisbane metropolitan area	Section 6.11.5
SEQ reactive power and voltage control	Section 6.5.1
Possible retirement of Loganlea 110/33kV transformer	Section 6.11.5

Note:

(1) Operational works, such as Over Load 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 Ergon Energy and Energex for maximum demand

Ergon Energy and Energex review and update the 10-year 50% probability of exceedance (PoE) and 10% PoE system summer maximum demand forecasts after each summer season. Each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency, the Ergon Energy and Energex forecast system level maximum demand is reconciled with the bottom-up substation maximum demand forecast after allowances for network losses and diversity of maximum demands.

Distribution forecasts are developed using data from Australian Bureau of Statistics (ABS), the Queensland Government, the Australian Energy Market Operator (AEMO), internally sourced rooftop photovoltaic (PV) connections and historical maximum demand data, and externally sourced Consumery Energy Resources (CER) forecast from an external consultant. The economic forecasts from Deloitte Access Economics are also utilised.

The methodology used to develop the system demand forecast, is as follows:

Ergon

- A six-region based forecast model within the Ergon network, with the aggregation of regions to provide a system peak 50% PoE. Each regional forecast uses a semi-parametric model to determine the relationship between demand and Gross State Product (GSP), population growth, temperature, lags of temperature, other weather variables and holiday periods. A Monte-Carlo process is used across the regional models to simulate a distribution of summer maximum demands using the latest 10 years of summer temperatures and an independent 10-year gross GSP and population forecast.
- Looking at *n* number of half hourly simulated demand traces a max of each of the simulated traces is used to capture a distribution of *n* max demand occurrences for each summer season going into the future. This includes calculating of the respective PoE 50 and PoE 10 for the distribution of maximum demand for each season used for the forecast values of maximum demand. A stochastic correlated term is applied to the simulated demands to capture the unexplained variance in the model fits. This process attempts to define the maximum demand rather than the regression average demand.
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for the expected impact of rooftop PV, battery storage and electric vehicles (EV) based on the maximum demand daily load profile and anticipated usage patterns.
- Further details of the methodology can be referenced in Rob J Hyndman, Shu Fan (2010) IEEE Transactions on Power Systems 25(2), 1142-1153 (latest version, with further development is 2015).

Energex

- Uses a multiple regression equation for the relationship between demand and GSP, square of weighted maximum temperature, weighted minimum temperature, coincident time relative humidity index, structural break, three continuous hot days, weekends, Fridays and the Christmas period. Three weather stations are incorporated into the model via a weighting system to capture the influence of the sea breeze on peak demand. Statistical testing is applied to the model before its application to ensure that there is minimal bias in the model. The summer regression uses data from November to March, with the temperature data excluding days where the weighted temperatures are below set levels (i.e; the weighted daily mean temperatures < 22.0°C and the weighted daily maximum temperature < 28.5°C).

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

- A Monte-Carlo process is used to simulate a distribution of summer maximum demands using the latest 22 years of summer weighted temperatures and an independent ten-year GSP forecast
- A stochastic term is applied to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the maximum demand rather than the regression average demand
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for rooftop PV, battery storage and the expected impact of EVs based on the maximum demand daily load profile and anticipated usage patterns.

C.2 Description of Ergon Energy's and Energex's high, medium and low growth scenarios for maximum demand

The scenarios developed for the high, medium and low case maximum demand forecasts were prepared in June 2023 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in July 2023 are based on the following assumptions.

Block Loads

There are many block loads scheduled over the next 11 years. For the majority, the block loads are incorporated at the relevant level of the network e.g. zone substation. Only a small number are considered large enough to justify accounting for them at the system level models. Ergon does not currently incorporate any block loads in the system level models. Energex has between 20MW and 70MW of block loads incorporated in the system model over the forecast horizon.

At the zone substation level, Energy Queensland is currently tracking around 220MW of block loads for Ergon, and 538MW for Energex. However, only the block loads which have a significant influence on the zone substation's peak demand are incorporated; for Ergon this is 189MW and for Energex 435MW.

Summary of the Ergon Energy model

The system demand model for regional Queensland incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Aggregation of six regional forecasts to provide a system peak 50PoE at network peak coincidence
- Demand MW = function of (weekend, public holidays, regional maximum temperature, Queensland GSP, population, structural break, demand management terms, and a constant)
- The demand management term captures historical movements of customer responses to the combination of PV uptake, tariff price changes and customer appliance efficiencies.

Ergon Energy's high growth scenario assumptions for maximum demand

- GSP – The "high" case of GSP growth (3% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Queensland regional population growth – 1.3% per annum (simple average growth for the 2024 ~ 2033 financial years).
- Weather – follow the recent trend of 10 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.1% per annum (simple average growth for the 2024 ~ 2033 financial years))
- Queensland regional population – Actual 1.6% in 2022, and 0.8% growth per annum (simple average growth for the 2024 ~ 2033 financial years)
- Weather – follow the recent 10-year trend.

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – The "low" case GSP growth (1.2% per annum (simple average growth for the 2024 ~ 2033 financial years))
- Queensland regional population growth – 0.3% per annum (simple average growth for the 2024 ~ 2033 financial years)
- Weather – follow the recent 10-year trend.

Summary of the Energex model

The latest system demand model for the South East Queensland region incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Demand MW = function of (weekend, Christmas, Friday, square of weighted maximum temperature, weighted minimum temperature, humidity index, total price, Queensland GSP, structural break, three continuous hot days, and a constant)
- In particular, the total price component incorporated into the latest model aims to capture the response of customers to the changing price of electricity. The impact of price is based on the medium scenarios for the Queensland residential price index forecast prepared by NIEIR in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – The "high" case of GSP growth (3% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a high technology penetration scenario, panel capacity may reach 10,638MW by 2033.
- Battery storage – Peak time (negative) contribution may reach 43MW by 2033 (behind the meter).
- EV – Price parity with the ICE type vehicles achieved earlier, accessible and fast charging stations, enhanced features, a variety of types, plus escalated petrol prices. The peak time contribution (without diversity ratio adjusted) may reach 411MW by 2033.
- Weather – follow the recent 10-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.1% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a medium technology penetration scenario, panel capacity may reach 9,082MW by 2033.
- Battery storage – Peak time (negative) contribution will have a slow start of around 7MW in 2024 but may reach 33MW by 2033 (behind the meter).
- EV – Stagnant in the short-term, surge in the long-term. Peak time contribution will only amount to 7MW in 2024 but will reach 233MW by 2033. Note however, EV will also have a significant impact on GWh energy sales.
- Weather – follow the recent 10-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – The "low" case GSP growth (1.2% per annum (simple average growth for the 2024 ~ 2033 financial years)).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a slow technology penetration scenario, panel capacity may reach 7,603MW by 2033.
- Battery storage – Peak time (negative) contribution may reach a high at 24MW in 2033 (behind the meter).
- EV – Price parity with the ICE type vehicles is achieved much later, hard to find charging stations, charging time remaining long, still having basic features, less type sections, plus lower cost petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 51MW in 2033.
- Weather – follow the recent 10-year trend.

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

Major differences between the 2023 forecast and the 2022 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. The forecast uptake of CER has decreased for the 2023 forecast when compared to the 2022 forecast. Electric vehicle charging behaviour has been revised and includes greater day time charging in the later years of the forecast, this has resulted in a decrease in the growth rate at many substations across Ergon and Energex. 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.

C.3.1 Ergon connection points with the greatest difference in growth between the 2023 and 2022 forecasts

Connection Point	kV	Change in growth rate (per annum)
Turkinje (Craiglie and Lakeland)	132	-2%
Woolooga (Kilkivan)	132	-2%
Rockhampton	66	-2%
Pandoin	66	-2%
Egans Hill	66	-2%
Woree (Cairns North)	132	-2%
Mackay	33	-2%
Tarong	66	-2%
Chinchilla	132	-2%
Calliope River	132	-2%
Cardwell	22	-2%
Dysart	66	-1%
Moranbah (Broadlea)	132	-1%
Middle Ridge (Postmans Ridge)	110	-1%
Teebar Creek (Isis and Maryborough)	132	-1%
Lilyvale (Barcaldine & Clermont)	132	-1%
Ingham	66	-1%
Tangkam	110	-1%
Middle Ridge	110	-1%
Biloela	66	-1%
Tully	22	-1%
Cairns City	132	-1%
El Arish	22	-1%
Gladstone South	66	-1%
Gin Gin	132	-1%
Bowen North	66	-1%
Edmonton	22	-1%
Oakey	110	-1.%
Alan Sherriff	132	-1%
Alligator Creek	33	-1%
Innisfail	22	-1%
Moura	66	-1%

C.3.2 Energex connection points with the greatest difference in growth between the 2023 and 2022 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 2022/23 summer was relatively mild 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 2022 forecast values for 2022/23 and what was observed.

C.4.1 Ergon connection points with the greater than 10% absolute difference between the peak 2022/23 and corresponding base 2022 forecast for 2022/23

Connection Point	2022/23 forecast peak	2022/23 actual peak	Difference
Pioneer Valley	84	52	-61%
Clare South	82	60	-35%
Moranbah (Broadlea)	62	48	-29%
Tangkam	33	27	-219%
Collinsville North	16	14	-188%
Ingham	23	19	-16%
Blackwater	137	122	-12%
Lilyvale	141	126	-12%
Mackay	99	88	-12%
Teebar Creek (Isis and Maryborough)	160	144	-11%
Proserpine	56	50	-11%
Aligator Creek (Louisa Creek)	41	37	-10%

C.4.2 Energex connection points with the greater than 10 % absolute difference between the peak 2022/23 and corresponding base 2022 forecast for 2022/23

Connection Point	2022/23 forecast peak	2022/23 actual peak	Difference
Redbank Plains	35	27.97	-26.558%
Middle Ridge (Postmans Ridge and Gatton)	129	102.57	-26.219%
Woolooga (Gympie)	248	213.36	-16.081%
Murarrie	542	489.45	-10.699%
Wecker Road	133	120.62	-10.184%

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, medium and low growth scenarios (refer to Appendix C.2). These forecasts have been supplied by Powerlink customers.

The connection point 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
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	New 132kV double circuit transmission line	Maintain supply reliability to the Far North zone	December 2028 (1)	Two 132kV single circuit transmission lines (2)	$52m
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 December 2029	New transmission line (2)	$37m
Substations					
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2029 (1)	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 (1)	Selected replacement of 132kV secondary systems	$6m
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2031 (1)	Selected replacement of 132kV secondary systems	$4m
Turkinje 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Far North zone	December 2026	Full replacement of 132kV primary plant	$4m
Kamerunga 132kV Substation rebuild	Full replacement 132kV primary plant and secondary systems	Maintain supply reliability to Cairns northern beaches area	December 2028	Selected replacement of 132kV primary plant and secondary systems (2)	$75m
Kamerunga 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to Cairns northern beaches area	June 2029	Significant load transfers in distribution network Early replacement with higher capacity transformer by 2023 triggered by load growth	$6m
Chalumbin 275kV and 132kV primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Far North zone	June 2029	Full replacement of all 275kV and 132kV primary plant and secondary systems	$7m

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
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	$39m
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 (1)	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 (1)	Full replacement of 275kV and 132kV secondary systems	$5m

Notes:

(1) The change in timing of the network solution from the 2022 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.

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	December 2029	New 132kV transmission line	$5m
Line refit works on the 132kV transmission line between Townsville South and Ross substations	Targeted line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	December 2029	New 132kV transmission line Targeted line refit works on steel lattice structures with painting	$4m
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	December 2029	New 132kV transmission line	$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	$10m
Substations					
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2032 (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	$12m
Ingham South 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	December 2027	Selected replacement of 132kV secondary systems (2)	$8m (3)
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Selected replacement of 132kV secondary systems Up to 110MW at peak and up to 800MWh per day to support the 66kV network in north east Townsville	$10m
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2033 (1)	Full replacement of secondary systems	$4m

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 South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2033 (1)	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)	$16m
Yabulu South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Full replacement of 132kV secondary systems	$7m
Clare South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2034 (1)	Full replacement of 132kV secondary systems	$12m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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 2029	New transmission line	$33m
Substations					
Alligator Creek 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2024	Full replacement of 132kV primary plant	$4m
North Goonyella 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	December 2031 (1)	Selected replacement of 132kV secondary systems	$6m
Nebo 132/11kV transformers replacement	Replacement of 132kV transformers	Maintain supply reliability to the North zone	December 2025	(2)	$12m
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2026	Staged replacement of secondary systems (2)	$7m
Kemmis 132/66kV transformer replacement	Replacement of one 132/66kV transformers	Maintain supply reliability to the North zone	December 2026	Establish 66kV supply from surrounding network (2)	$7m (3)
Pioneer Valley 132kV primary plant replacement	Selected replacement of 132kV secondary systems equipment	Maintain supply reliability to the North zone	June 2029	Full replacement of 132kV secondary systems	$5m
Strathmore 275kV and 132kV secondary systems	Selected replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the North zone	June 2034 (1)	Selected replacement of 275kV and 132kV secondary systems in existing panels	$15m
Alligator Creek SVC and 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2028 (1)	Staged replacement of 132kV secondary systems	$7m
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)	$6m

Notes:

(1) The revised timing from the 2022 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 2022 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 132kV transmission line between Calvale, Biloela and Moura	Line refit works on the 132kV transmission line and repair selected foundations	Maintain supply reliability to the Central West zone	June 2025	Rebuild the 132kV transmission lines as a double circuit from Callide A to Moura Line refit works on the 132kV transmission line and repair all foundations	$5m
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 2029	Stanwell to Broadsound second side stringing New 275kV transmission line between Bouldercombe and Broadsound substation	$31m
Substations					
Blackwater 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Central West zone	June 2025	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 (1)	Full replacement of 132kV secondary systems	$5m
Broadsound 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability to the Central West zone	June 2032 (1)	Full replacement of 275kV secondary systems	$4m
Broadsound 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2027	Full replacement of 275kV primary plant (2)	$19m (3)
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2033 (1)	Full replacement of 132kV secondary systems	$3m
Calvale 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2028	Full replacement of 275kV primary plant (2)	$18m (3)
Blackwater 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2034 (1)	Full replacement of 132kV secondary systems	$13m
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 (1)	Full replacement of 132kV and 275kV secondary systems	$10m

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
Nebo SVC secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability to the Central West zone and Northern region	June 2030	Full replacement secondary systems	$6m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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 2025	Rebuild the 275kV transmission line between Wurdong and Boyne Island	$5m (1)
Rebuild the 132kV transmission line between Callemondah and Gladstone South Substation	Rebuild the 132kV double circuit transmission line between Callemondah and Gladstone South Substation	Maintain supply reliability in the Gladstone zone	June 2026	Line refit works on steel lattice structures (2)	$53m (1)
Rebuild the 275kV transmission line between Calliope River and Larcom Creek substations	Rebuild the 275kV transmission line between Calliope River and Larcom Creek substations as double circuit high capacity transmission line and turn in one or both circuits to Larcom Creek Substation	Maintain supply reliability in the Gladstone zone	June 2029 (4)	Line refit works on the 275kV transmission line between Larcom Creek substation and Mt Miller near Calliope River (2)	$107m (1)
Rebuild the 275kV transmission line between Bouldercombe and Calliope River substations	Rebuild the 275kV transmission line between Bouldercombe and Calliope River substation	Maintain supply reliability in the Gladstone zone	December 2029 (4)	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Bouldercombe and Larcom Creek as a double circuit transmission line, and mothball section from Cedarvale to Calliope River	$320m (3)
Line refit works on steel lattice structures on the 275kV transmission line between Raglan and Larcom Creek substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2030	Rebuild the 275kV transmission line between Raglan and Larcom Creek	$15m (3)
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 275kV transmission line between Bouldercombe and Bouldercombe Tee	$3m

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 275kV transmission line between Raglan and Bouldercombe substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2032	Rebuild the 275kV transmission line between Raglan and Bouldercombe	$20m (3)
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 2025	Full replacement of 132kV primary plant and secondary systems (1)	$10m
Rockhampton 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain reliability in Rockhampton	June 2031 (1)	Full replacement of 132kV secondary systems	$5m
Larcom Creek 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034 (1)	Full replacement of the 275kV secondary systems	$8m
Pandoin 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2034 (1)	Selected replacement of 132kV secondary systems	$5m
Bouldercombe 275kV secondary systems replacement	Full replacement of the 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2032	Selected replacement of 275kV secondary systems	$25m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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.

(4) The required timing for this network investment will depend on the overall supply and demand balance in the Gladstone zone. This is impacted by the future operation of the Gladstone PS and the development of new loads associated with decarbonising existing industrial processes and new industries.

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 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 2028	Refit the two single circuit 275kV transmission lines	$40m (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 2029 (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 (2)	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$16m (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	June 2030	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$75m
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	$8m (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	December 2032 (2)	Refit the 275kV transmission line between Gin Gin and Woolooga substations	$27m (1)
Substations					
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2033 (2)	Selected replacement of 132kV and 275kV secondary systems	$19m
Woolooga 275kV and 132kV primary plant and secondary systems replacement	Selected replacement of 275kV and 132kV primary plant and full replacement of 132kV and 275kV secondary systems (including SVC)	Maintain supply to the Wide Bay zone	December 2034 (2)	Selected replacement of 275kV and 132kV secondary systems	$34m (1)

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
Palmwoods 275kV and 132kV selected primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply to the Wide Bay zone	December 2029 (2)	Full replacement of 275kV and 132kV primary plant	$15m (1)

Notes:

(1) Compared to the 2022 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 2022 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	$15m

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 (1)	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 (1)	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

Note:

(1) The change in timing of the network solution from the 2022 TAPR is based upon updated information on the condition of the assets.

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 at Middle Ridge Substation	June 2028	Full replacement of 110kV primary plant	$3m
Tangkam 110kV primary plant replacement	Selected replacement of selected 110kV primary plant	Maintain reliability of supply at Tangkam Substation	June 2030	Full replacement of 110kV primary plant	$12m
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 (1)	Full replacement of 275kV and 110kV secondary systems	$40m

Note:

(1) The change in timing of the network solution from the 2022 TAPR is based upon updated information on the condition of the assets.

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 (1)	In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (2)	$13m
Line refit works on the 110kV transmission line between Belmont and Murarrie substations	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	June 2032 (1)	Rebuild the 110kV transmission lines between Belmont and Murarrie substations	$2m
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 (1)	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	$8m
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 (3)
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 (3)
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

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
South Pine 275/110kV transformer life extension	Life extension of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	June 2026	Retirement of a single 275kV/110kV transformer with non-network support	$3m
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2031 (1)	Staged replacement of 110kV secondary systems	$11m
Sumner 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2025	Staged replacement of 110kV secondary systems	$5m
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2031 (1)	Staged replacement of 110kV secondary systems	$17m
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2032 (1)	Staged replacement of 110kV secondary systems	$7m
Rocklea 110kV primary plant replacement	Full replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	December 2028	Staged replacement of 110kV primary plant	$5m
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of 110kV primary plant	$8m
South Pine SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of SVC secondary systems	$6m
Goodna 110/332kV transformer augmentation	Installation of a 100MVA 110/33kV transformer	Maintain supply reliability in the Moreton zone	June 2028	Installation of a smaller 110/33kV transformer and non-network support	$6m
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	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 (1)	Staged replacement of 110kV secondary systems	$11m
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2029	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 2029	Staged replacement of 275kV primary plant	$5m
Greenbank SVC and 275kV secondary systems replacement	Full replacement of 275kV SVC and secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	December 2029	Staged replacement of 275kV SVC and secondary systems	$33m
Mount England 275kV secondary systems and primary plant replacement	Full replacement of 275kV secondary systems and staged replacement of primary plant	Maintain supply reliability in the Moreton zone	June 2034 (1)	Staged replacement of 275kV secondary systems and primary plant	$11m

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Belmont 110kV and 275kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2034 (1)	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 (1)	Staged replacement of 22kV and 11kV primary plant	$5m
South Pine 275kV primary plant replacement	Staged replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2030	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 2034 (1)	Staged replacement of 275kV and 110kV secondary systems	$6m (3)
South Pine secondary systems replacement	Replacement of secondary systems at South Pine 275kV	Maintain supply reliability in the Moreton zone	June 2034	Staged replacement of secondary systems	$50m
Abermain 275kV and 110kV primary plant replacement	Selected 275kV and 110kV primary plant replacement	Maintain supply reliability in the Moreton zone	June 2034	Full replacement of 275kV and 110kV primary plant	$8m

Notes:

(1) The change in timing of the network solution from the 2022 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 2022 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	December 2028	Full line refit New transmission line	$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	December 2028	New double circuit 275kV transmission line (1)	$30m
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2030 (2)	Selected replacement of 275kV secondary systems	$23m (3)
Mudgeeraba 110kV primary plant and secondary systems replacement	Selected replacement of 110kV primary plant and staged replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2029	Full replacement of 110kV secondary systems (1)	$33m
Mudgeeraba 275/110kV Transformer Replacement	Replacement of the transformer	Maintain supply reliability to the Gold Coast Region	December 2030	Life extension of the existing transformer	$11m

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 2022 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2022 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 AER's 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 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 near-term 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. 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).

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 an in-house tool. These daily demand profiles are an estimate and should only be used as a guide. 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).

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

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).

Powerlink's in-house load profiling tool incorporates a base year (1 July 2020 to 1 July 2021) of historical demand and weather data (temperature and solar irradiance) for all loads supplied from the Queensland transmission network. The tool then adds at the connection point level the impacts of future forecasts of rooftop PV, distribution connected PV solar farms, battery storage, EV and load growth.

The maximum demand of every connection point within the base year has been scaled to the medium growth 50% PoE maximum demand connection point forecasts, as supplied by Powerlink's customers post-winter 2021 (the previous revision of those listed in Appendix C).

As Powerlink does not receive a minimum demand connection point forecast from its customers, the minimum demand is not scaled. The minimum demand is determined by the base year's half hour demands and the impacts of rooftop PV, distribution connected PV solar farms, battery storage and EV.

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	Forecast maximum load at risk is the raw data and does not reflect the requirements of Powerlink's jurisdictional planning standard used to calculate non-network solution requirements. Refer to chapters 5 and 6 for information.
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 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR) (as shown in figures 7.6 – 7.8).

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 is each zone.

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

Table F.1 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of King Creek and Bowen North, excluding the Far North zone
North	North of Broadsound and Dysart, excluding the Far North 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 Millmerran
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	Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)
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) Millmerran 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				•			
	Clarke Creek (1)					•		
Central West	Callide B	•						
	Callide PP	•						
	Stanwell	•						
	Lilyvale				•			
	Moura				•			
	Bouldercombe						•	
Gladstone	Gladstone	•						
	Yarwun		•					
Wide Bay	Woolooga Energy Park				•			
Moreton	Swanbank E		•					
	Wivenhoe			•				

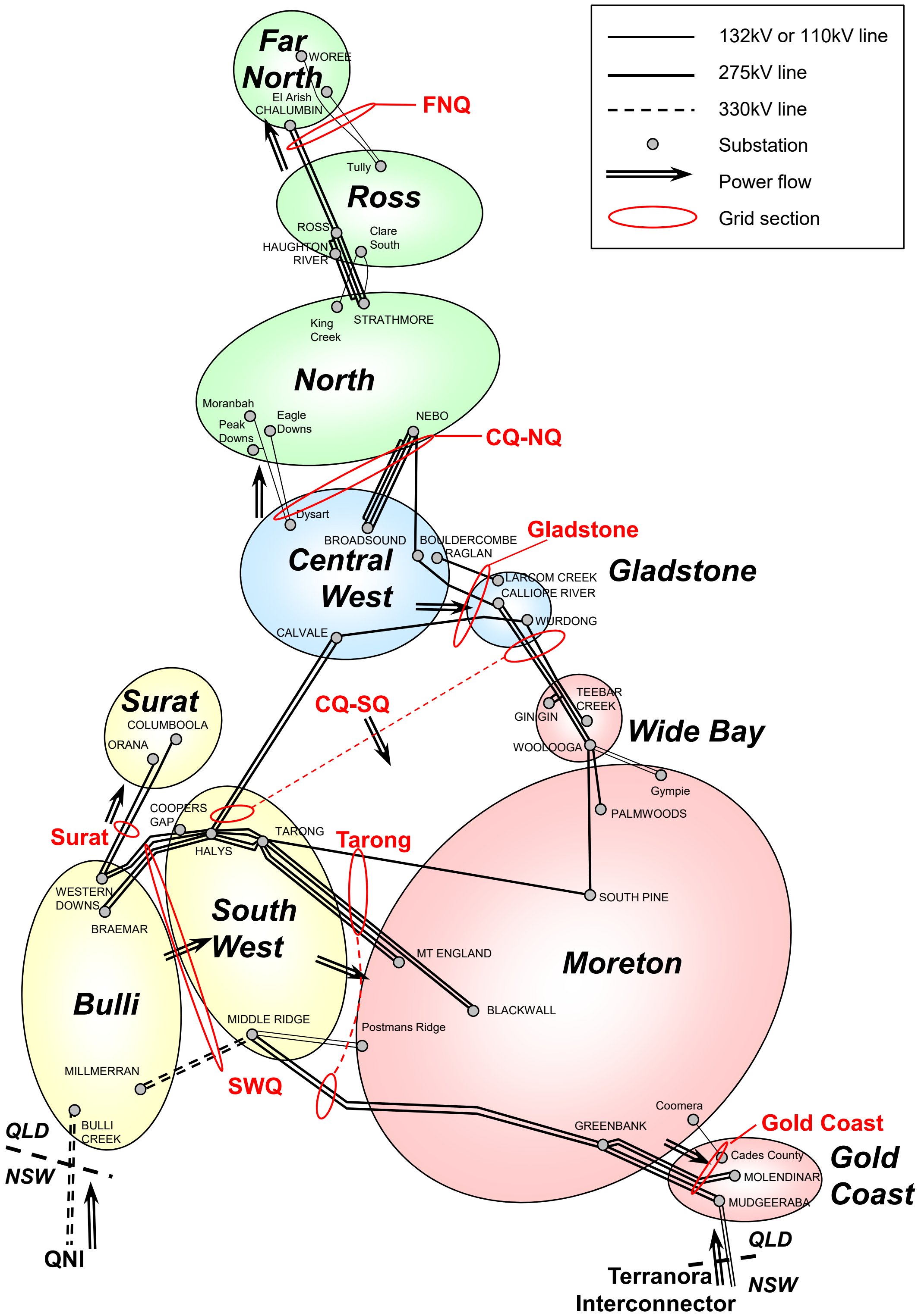
Table F.3 Zone Generation details (*continued*)

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
South West	Tarong	•						
	Tarong North	•						
	Oakey		•					
	Wambo (1)					•		
	Coopers Gap					•		
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
	Chinchilla (1)						•	
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 take into account 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	
	Equation 1 Woree SVC	Equation 2 Mt Emerald Wind Farm
Constant term (intercept)	574	568
Number of Barron Gorge units on line [0 to 2]	21	-
Total MW generation at Barron Gorge	-0.83	-0.25
Total MW generation at Mt Emerald Wind Farm	-0.59	-0.96
Total MW generation at Kaban Wind Farm	-0.59	-0.96
Total MW generation at Kareeya Power Station	-0.51	-0.62
Total MW generation in Ross zone (1)	-	0.09
Total nominal MVAr of 132kV shunt capacitors on line within nominated Cairns area locations (2)	0.52	0.68
Total nominal MVAr of 275kV shunt reactors on line within nominated Cairns area locations (3)	-	-1.45
Total nominal MVAr of 132kV shunt reactors on line within nominated Chalumbin area locations (4)	-0.35	-0.45
Total nominal MVAr of 275kV shunt reactors on line within nominated Chalumbin area locations (5)	-0.42	-0.36
AEMO Constraint ID	Q^NIL_FNQ_MRSVC	Q^NIL_FNQ_MEWF

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

Table G.3 North Queensland system strength equations

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.

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	Other NQ Plants
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 350	> 150	OFF	25	25	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	OFF	0	0	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 0	> 250	> 100	ON	100	100	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	50	50	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	ON	100	100	100
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	OFF	50	50	80
≥ 1	≥ 4	≥ 1	≥ 6	≥ 2	> 350	> 150	ON	100	50	100
≥ 2	≥ 3	≥ 1	≥ 7	≥ 2	> 350	> 150	OFF	N/A	100	Wind = 100 Solar = N/A
AEMO Constraint ID								Q_NIL_STRGTH_HAUSF	Q_NIL_STRGTH_KBWF	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_MEWF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_RUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

System normal equations are implemented for all other north Queensland semi-scheduled generators (Mt Emerald Wind Farm, Ross River Solar Farm, Kidston Solar Farm, Kennedy Energy Park, Clare Solar Farm, Sun Metals Solar Farm, Whitsunday Solar Farm, Hamilton Solar Farm, Daydream Solar Farm, Hayman Solar Farm, Collinsville Solar Farm and Rugby Run Solar Farm) to ensure system security is maintained during abnormally low synchronous generator dispatches. These equations allow unconstrained operation for all but one condition of Table G.3 where operation is constrained to 80%. Conditions resulting in lower synchronous unit capacity is constrained to 0.

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 Battery Energy System, 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, 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
	CalvaleHalys 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, 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 18 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 16 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 2023/24, 2024/25 and 2025/26.

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 2022 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 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.

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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Alan Sherriff	132	31.5	4.1	3.8	13.4	13.8	13.4	13.7	13.7	13.9	1.0343	Ross 275kV
Alligator Creek	132	31.5	3.1	1.8	4.4	5.9	4.4	5.8	4.4	5.8	1.1302	Ross 275kV
Aurumfield	275	40.0	1.2	1.1	-	-	-	-	3.7	4.6	1.1060	Ross 275kV
Bolingbroke	132	31.5	2.0	1.9	2.5	1.9	2.4	1.9	2.5	1.9	1.2135	Ross 275kV
Bowen North	132	31.5	2.1	0.7	3.0	3.2	2.9	3.2	3.0	3.2	1.1639	Ross 275kV
Cairns (2T)	132	31.5	3.1	0.5	6.5	8.5	6.5	8.6	6.8	8.9	1.0762	Ross 275kV
Cairns (3T)	132	31.5	3.1	0.5	6.5	8.5	6.5	8.6	6.8	8.9	1.0762	Ross 275kV
Cairns (4T)	132	31.5	3.1	0.5	6.5	8.6	6.5	8.7	6.8	9.0	1.0761	Ross 275kV
Cardwell	132	31.5	2.0	0.9	3.3	3.6	3.3	3.6	3.3	3.6	1.1447	Ross 275kV
Chalumbin	275	40.0	2.0	1.6	4.8	5.2	4.8	5.3	5.3	5.7	1.0453	Ross 275kV
Chalumbin	132	31.5	3.4	2.7	7.1	8.2	7.1	8.2	7.4	8.5	1.0790	Ross 275kV
Clare South	132	31.5	3.4	3.0	8.2	8.2	8.1	8.1	8.2	8.2	1.0696	Ross 275kV
Collinsville North	132	31.5	5.2	4.5	11.4	12.2	11.3	12.1	11.6	12.2	1.0432	Ross 275kV
Coppabella	132	31.5	2.2	1.5	3.1	3.4	3.0	3.4	3.0	3.4	1.1863	Ross 275kV
Crush Creek	275	40.0	3.5	3.0	10.4	11.6	10.3	11.5	10.7	11.8	1.0200	Ross 275kV
Dan Gleeson (1T)	132	31.5	4.1	3.8	12.8	13.2	12.8	13.1	13.0	13.3	1.0346	Ross 275kV
Dan Gleeson (2T)	132	31.5	4.1	3.8	12.8	13.3	12.8	13.2	13.0	13.4	1.0346	Ross 275kV
Edmonton	132	31.5	2.9	0.9	5.9	7.1	5.9	7.1	6.1	7.3	1.0835	Ross 275kV
Eagle Downs	132	31.5	3.0	1.5	4.6	4.5	4.6	4.4	4.6	4.4	1.1292	Lillyvale 132kV
El Arish	132	31.5	2.3	1.0	3.7	4.5	3.7	4.5	3.8	4.6	1.1219	Ross 275kV
Garbutt	132	31.5	3.8	1.7	11.0	11.0	11.0	10.9	11.2	11.0	1.0423	Ross 275kV
Greenland	132	31.5	3.5	2.1	5.6	5.0	5.5	5.0	5.5	5.0	1.1150	Ross 275kV
Goonyella Riverside	132	31.5	3.5	3.1	6.1	5.5	6.0	5.4	6.0	5.4	1.1075	Ross 275kV
Guybal Munjan	275	40.0	2.2	1.9	-	-	5.4	4.7	6.5	5.3	1.0265	Ross 275kV
Haughton River	275	40.0	2.7	2.1	8.0	8.3	8.0	8.2	8.4	8.5	1.0132	Ross 275kV
Ingham South	132	31.5	1.9	1.1	3.4	3.5	3.4	3.4	3.4	3.5	1.1543	Ross 275kV
Innisfail	132	31.5	2.1	1.3	3.2	3.9	3.2	3.8	3.3	3.9	1.1438	Ross 275kV
Invicta	132	31.5	2.6	2.4	5.3	4.8	5.3	4.8	5.3	4.8	1.1069	Ross 275kV
Kamerunga	132	31.5	2.8	2.5	5.8	7.0	5.8	7.0	6.0	7.2	1.0906	Ross 275kV
Kamerunga	132	31.5	2.8	2.5	5.8	7.0	5.8	7.0	6.0	7.2	1.0906	Ross 275kV
Kareeya	132	31.5	3.2	2.4	6.0	6.6	6.0	6.6	6.2	6.8	1.0957	Ross 275kV
Kemmis	132	31.5	4.0	1.6	6.1	6.6	6.1	6.5	6.1	6.6	1.1009	Ross 275kV
King Creek	132	31.5	3.2	1.4	5.5	4.4	5.5	4.4	5.5	4.4	1.0889	Ross 275kV
Lake Ross	132	31.5	4.7	4.2	17.7	19.8	17.7	19.6	18.3	20.1	1.0212	Ross 275kV
Mackay	132	31.5	3.4	2.9	5.0	6.1	5.0	6.0	5.0	6.0	1.1190	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Mackay Ports	132	31.5	2.6	1.6	3.4	4.1	3.4	4.0	3.4	4.1	1.1612	Ross 275kV
Mindi	132	31.5	3.5	3.3	4.9	3.7	4.8	3.7	4.9	3.7	1.1167	Ross 275kV
Moranbah	132	31.5	4.0	3.3	8.0	9.5	7.9	9.4	8.0	9.4	1.0970	Ross 275kV
Moranbah Plains	132	31.5	2.7	2.3	4.4	4.8	4.4	4.7	4.4	4.8	1.1533	Ross 275kV
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.2	5.7	5.2	1.1209	Ross 275kV
Mt Mclaren	132	31.5	1.6	1.4	2.1	2.3	2.1	2.3	2.1	2.3	1.2707	Ross 275kV
Nebo	275	40.0	4.6	4.0	11.6	11.7	11.4	12.7	11.9	13.0	1.0371	Ross 275kV
Nebo	132	31.5	7.1	6.2	14.0	16.0	13.8	16.2	14.1	16.4	1.0525	Ross 275kV
Newlands	132	31.5	2.5	1.3	3.6	4.0	3.6	4.0	3.6	4.0	1.1484	Ross 275kV
North Goonyella	132	31.5	2.9	2.5	4.5	3.7	4.5	3.7	4.5	3.7	1.1319	Ross 275kV
Oonooie	132	31.5	2.4	1.5	3.1	3.7	3.1	3.6	3.1	3.6	1.1772	Ross 275kV
Peak Downs	132	31.5	2.8	2.1	4.2	3.7	4.2	3.7	4.2	3.7	1.1360	Lillyvale 132kV
Pioneer Valley	132	31.5	4.1	3.6	6.6	7.5	6.5	7.4	6.6	7.4	1.0966	Ross 275kV
Proserpine	132	31.5	2.5	1.8	3.5	4.0	3.5	4.0	3.5	4.0	1.1375	Ross 275kV
Ross	275	40.0	2.8	2.5	9.4	10.4	9.3	10.4	10.1	11.1	1.0000	Ross 275kV
Ross	132	31.5	4.7	4.3	18.3	20.6	18.2	20.4	18.9	20.9	1.0203	Ross 275kV
Springlands	132	31.5	5.5	4.7	12.6	14.4	12.5	14.2	12.8	14.4	1.0385	Ross 275kV
Stony Creek	132	31.5	2.7	1.2	3.8	3.7	3.8	3.6	3.8	3.7	1.1341	Ross 275kV
Strathmore	275	40.0	3.5	3.0	10.5	11.7	10.4	11.6	10.8	12.0	1.0197	Ross 275kV
Strathmore	132	31.5	5.6	4.8	13.1	15.3	13.0	15.1	13.2	15.4	1.0371	Ross 275kV
Townsville East	132	31.5	3.9	1.6	13.0	12.6	13.0	12.6	13.2	12.7	1.0424	Ross 275kV
Townsville South	132	31.5	4.2	3.9	17.6	21.2	17.5	21.1	17.9	21.4	1.0326	Ross 275kV
Townsville GT PS	132	31.5	3.4	2.4	10.0	10.6	9.9	10.4	10.1	10.5	1.0557	Ross 275kV
Tully	132	31.5	2.7	1.5	4.8	5.6	4.9	5.6	5.0	5.7	1.0901	Ross 275kV
Tully South	275	40.0	1.7	0.6	3.7	3.6	3.8	3.7	3.9	3.8	1.0514	Ross 275kV
Tumoulin	275	40.0	1.8	1.3	4.2	4.9	4.2	4.6	4.5	4.9	1.0540	Ross 275kV
Turkinje	132	31.5	1.8	1.2	2.8	3.1	2.8	3.1	2.8	3.2	1.1933	Ross 275kV
Walkamin	275	40.0	1.7	1.4	4.0	4.6	4.0	4.6	4.3	4.9	1.0576	Ross 275kV
Wandoo	132	31.5	3.3	3.1	4.5	3.3	4.5	3.3	4.5	3.3	1.1241	Ross 275kV
Woree (1T)	275	40.0	1.8	1.5	4.3	5.1	4.3	5.1	4.5	5.4	1.0531	Ross 275kV
Woree (2T)	132	31.5	3.2	2.7	6.8	9.2	6.8	9.3	7.1	9.6	1.0730	Ross 275kV
Wotonga	132	31.5	3.6	1.7	6.2	7.2	6.2	7.1	6.2	7.2	1.1105	Ross 275kV
Yabulu South	132	31.5	3.8	3.2	11.1	10.8	11.1	10.2	11.3	10.4	1.0444	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Baralaba	132	31.5	3.4	2.1	4.3	3.7	4.3	3.7	4.3	3.7	1.1422	Lillyvale 132kV
Biloela	132	31.5	6.1	3.5	7.9	8.2	8.0	8.2	8.0	8.2	1.0893	Gin Gin 275kV
Blackwater	132	31.5	4.0	3.3	5.9	7.1	5.9	7.0	5.9	7.0	1.0480	Lillyvale 132kV
Bluff	132	31.5	2.6	2.3	3.5	4.3	3.4	4.2	3.4	4.3	1.1057	Lillyvale 132kV
Bouldercombe	275	40.0	10.2	8.7	20.7	20.0	21.1	19.8	21.4	19.9	1.0374	Gin Gin 275kV
Bouldercombe	132	31.5	10.3	6.3	14.4	16.7	14.4	15.8	14.5	15.8	1.0594	Gin Gin 275kV
Broadsound	275	40.0	6.0	4.9	15.1	16.0	14.7	15.3	15.3	16.9	1.0434	Lillyvale 132kV
Bundoora	132	31.5	5.2	4.4	9.4	9.1	9.3	9.0	9.3	9.0	1.0120	Lillyvale 132kV
Callemondah	132	31.5	16.9	6.9	22.0	24.6	22.1	24.7	22.2	24.7	1.0396	Gin Gin 275kV
Calliope River	275	40.0	11.8	10.2	20.9	24.0	21.2	24.1	21.3	24.2	1.0230	Gin Gin 275kV
Calliope River	132	31.5	18.7	15.3	24.7	29.8	24.8	29.9	24.9	29.9	1.0372	Gin Gin 275kV
Calvale (1T)	275	40.0	10.3	8.5	21.1	22.1	23.9	26.2	24.0	26.2	1.0379	Gin Gin 275kV
Calvale (2T)	132	31.5	6.6	2.8	8.7	9.5	8.8	9.6	8.8	9.6	1.0841	Gin Gin 275kV
Calvale	132	31.5	6.8	3.0	8.4	9.1	8.5	9.3	8.5	9.3	1.0823	Gin Gin 275kV
Duaringa	132	31.5	1.9	1.6	2.3	2.9	2.2	2.9	2.2	2.9	1.2140	Lillyvale 132kV
Dysart	132	31.5	3.2	1.9	4.8	5.4	4.8	5.3	4.8	5.3	1.1039	Lillyvale 132kV
Egans Hill	132	31.5	6.4	1.6	8.3	8.1	8.3	8.0	8.3	8.0	1.0851	Gin Gin 275kV
Gladstone PS	275	40.0	11.2	9.7	19.4	21.8	19.7	21.9	19.8	22.0	1.0241	Gin Gin 275kV
Gladstone PS	132	31.5	16.9	13.5	21.7	24.9	21.8	25.0	21.9	25.1	1.0411	Gin Gin 275kV
Gladstone South	132	31.5	12.8	10.0	16.2	17.2	16.2	17.2	16.3	17.2	1.0479	Gin Gin 275kV
Grantleigh	132	31.5	2.3	2.0	2.7	2.8	2.7	2.8	2.7	2.8	1.2083	Gin Gin 275kV
Gregory	132	31.5	5.7	4.7	10.5	11.7	10.3	11.5	10.4	11.6	1.0027	Lillyvale 132kV
Larcom Creek	275	40.0	9.2	3.3	15.5	16.4	15.6	15.7	15.7	15.8	1.0295	Gin Gin 275kV
Larcom Creek	132	31.5	8.2	4.2	12.3	13.9	12.3	13.8	12.3	13.8	1.0597	Gin Gin 275kV

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
					2023/24		2024/25		2025/26			
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)		
Lilyvale	275	40.0	3.5	2.6	6.7	6.5	6.5	6.3	6.6	6.4	1.0216	Lillyvale 132kV
Lilyvale	132	31.5	5.9	4.8	11.1	12.8	10.9	12.6	11.0	12.7	1.0000	Lillyvale 132kV
Moura	132	31.5	3.2	1.5	4.3	5.3	4.2	5.2	4.3	5.2	1.1547	Gin Gin 275kV
Norwich Park	132	31.5	2.7	2.5	3.7	2.7	3.6	2.6	3.7	2.6	1.1087	Lillyvale 132kV
Pandoin	132	31.5	5.5	1.2	6.9	6.1	6.9	6.0	6.9	6.0	1.0971	Gin Gin 275kV
Raglan	275	40.0	7.7	4.3	12.0	10.7	12.1	10.5	12.1	10.5	1.0375	Gin Gin 275kV
Rockhampton (1T)	132	31.5	5.1	1.8	6.4	6.3	6.4	6.3	6.4	6.3	1.1022	Gin Gin 275kV
Rockhampton (5T)	132	31.5	5.0	1.8	6.2	6.1	6.2	6.1	6.2	6.1	1.1047	Gin Gin 275kV
Stanwell	275	40.0	10.8	9.0	23.5	24.9	24.2	25.2	24.4	25.3	1.0381	Gin Gin 275kV
Stanwell	132	31.5	4.8	3.7	5.9	6.4	5.9	6.3	5.9	6.3	1.1085	Gin Gin 275kV
Wurdong	275	40.0	10.3	6.6	16.6	16.6	16.9	16.8	17.0	16.8	1.0267	Gin Gin 275kV
Wycarbah	132	31.5	3.7	3.1	4.5	5.4	4.5	5.3	4.5	5.3	1.1346	Gin Gin 275kV
Yarwun	132	31.5	8.0	4.5	12.9	14.9	12.9	14.8	12.9	14.9	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Abermain	275	40.0	8.1	6.4	18.3	18.8	18.2	18.7	18.3	18.8	1.0054	Greenbank 275kV
Abermain	110	31.5	13.0	10.4	21.5	24.5	21.3	24.3	21.4	24.4	1.0209	Greenbank 275kV
Algester	110	31.5	12.9	11.6	21.1	20.8	20.9	20.7	21.0	20.8	1.0207	Greenbank 275kV
Ashgrove West	110	31.5	12.2	9.3	19.1	20.1	19.0	20.0	19.1	20.0	1.0258	Greenbank 275kV
Banana Bridge	275	40.0	7.6	5.2	-	-	25.8	27.4	25.9	27.5	1.0008	Western Downs 275kV
Belmont	275	40.0	7.9	7.2	17.0	17.9	16.9	17.8	17.0	19.0	1.0051	Greenbank 275kV
Belmont	110	31.5	15.4	14.4	27.8	34.4	27.6	34.2	27.8	34.6	1.0128	Greenbank 275kV
Blackstone	275	40.0	8.7	7.9	21.3	23.7	21.3	23.6	21.4	23.8	1.0017	Greenbank 275kV
Blackstone	110	31.5	14.6	13.4	25.4	28.0	25.3	27.8	25.4	27.9	1.0160	Greenbank 275kV
Blackwall	275	40.0	9.3	8.4	22.6	24.3	22.5	24.2	22.7	24.3	1.0048	Greenbank 275kV
Blythdale	132	31.5	3.2	2.3	4.3	5.3	4.3	5.3	4.3	5.4	1.1108	Western Downs 275kV
Braemar	330	50.0	7.0	5.7	24.3	26.3	24.3	26.4	24.5	26.5	1.0085	Western Downs 275kV
Braemar (East)	275	40.0	8.2	5.3	27.5	31.8	27.5	31.8	27.6	31.9	1.0117	Western Downs 275kV
Braemar (West)	275	40.0	7.9	4.7	28.8	31.7	28.9	31.7	29.0	31.9	1.0048	Western Downs 275kV
Bulli Creek	330	50.0	6.8	6.2	18.6	14.9	18.6	15.0	18.8	15.1	1.0171	Western Downs 275kV
Bulli Creek	132	31.5	3.0	3.0	3.8	4.3	3.8	4.3	4.3	4.8	1.1366	Western Downs 275kV
Bundamba	110	31.5	11.1	7.7	17.2	16.6	17.1	16.5	17.2	16.5	1.0275	Greenbank 275kV
Cameby	132	31.5	6.0	5.0	11.0	9.7	9.7	8.9	9.7	9.0	1.0516	Western Downs 275kV
Chinchilla	132	31.5	5.3	4.6	8.7	10.1	7.1	8.5	7.1	8.5	1.0623	Western Downs 275kV
Clifford Creek	132	31.5	4.1	3.3	6.0	5.4	6.0	5.4	6.0	5.4	1.0805	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Columboola	275	40.0	5.5	4.3	14.2	13.3	14.2	13.3	14.2	13.3	1.0120	Western Downs 275kV
Columboola	132	31.5	7.7	6.0	18.2	21.3	17.8	20.7	17.9	20.7	1.0325	Western Downs 275kV
Condabri Central	132	31.5	5.4	4.5	9.5	7.0	9.4	7.0	9.4	7.0	1.0566	Western Downs 275kV
Condabri North	132	31.5	6.9	5.5	14.4	13.3	14.2	13.1	14.2	13.1	1.0394	Western Downs 275kV
Condabri South	132	31.5	4.4	3.6	6.8	4.6	6.8	4.6	6.8	4.6	1.0761	Western Downs 275kV
Coopers Gap	275	40.0	8.1	3.2	18.0	17.8	17.7	17.7	17.9	17.8	1.0155	Western Downs 275kV
Diamondy	275	40.0	7.7	6.8	-	-	14.4	11.5	14.9	11.8	1.0217	Western Downs 275kV
Dinoun South	132	31.5	4.5	3.6	6.9	7.1	6.9	7.1	6.9	7.1	1.0702	Western Downs 275kV
Eurombah (1T)	275	40.0	2.8	1.2	4.7	4.9	4.7	4.9	4.7	4.9	1.0486	Western Downs 275kV
Eurombah	132	31.5	4.7	3.5	7.3	8.9	7.3	8.9	7.3	8.9	1.0667	Western Downs 275kV
Fairview	132	31.5	3.1	2.5	4.1	5.2	4.1	5.2	4.1	5.2	1.1171	Western Downs 275kV
Fairview South	132	31.5	3.8	3.0	5.4	6.8	5.4	6.8	5.5	6.9	1.0890	Western Downs 275kV
Gin Gin	275	40.0	6.4	4.4	9.3	8.7	9.5	9.0	9.6	9.1	1.0000	Gin Gin 275kV
Gin Gin	132	31.5	8.9	7.0	12.0	13.0	12.5	13.7	12.7	13.8	1.0184	Gin Gin 275kV
Goodna	275	40.0	7.8	5.6	16.3	16.0	16.2	15.9	16.3	16.0	1.0078	Greenbank 275kV
Goodna	110	31.5	14.7	12.9	25.5	27.5	25.3	27.3	25.5	27.5	1.0164	Greenbank 275kV
Greenbank	275	40.0	8.5	7.8	20.6	23.6	20.5	23.5	20.6	23.7	1.0000	Greenbank 275kV
Halys	275	40.0	11.8	10.2	33.2	28.8	32.9	29.4	33.5	29.8	1.0124	Western Downs 275kV
Kumbarilla Park	275	40.0	6.7	1.7	16.9	16.2	16.9	16.2	17.0	16.3	1.0171	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Kumbarilla Park	132	31.5	8.3	5.5	13.2	15.2	13.2	15.2	13.3	15.3	1.0383	Western Downs 275kV
Loganlea	275	40.0	7.3	6.1	15.0	15.5	14.9	15.4	15.0	15.6	1.0059	Greenbank 275kV
Loganlea	110	31.5	13.4	12.0	22.7	27.3	22.6	27.2	22.7	27.4	1.0170	Greenbank 275kV
Middle Ridge (4T)	330	50.0	5.8	3.2	12.7	12.3	12.8	12.5	12.8	12.5	1.0175	Western Downs 275kV
Middle Ridge (5T)	330	50.0	5.9	3.2	13.1	12.8	13.2	12.9	13.2	12.9	1.0169	Western Downs 275kV
Middle Ridge	275	40.0	7.6	6.7	18.3	18.4	18.3	18.5	18.4	18.6	1.0136	Western Downs 275kV
Middle Ridge	110	31.5	10.6	8.8	21.3	25.1	21.4	25.0	21.4	25.1	1.0350	Western Downs 275kV
Millmerran	330	50.0	6.3	5.9	18.6	19.9	18.6	20.5	18.7	20.6	1.0198	Western Downs 275kV
Molendinar (1T)	275	40.0	5.0	2.1	8.2	8.1	8.2	8.0	8.2	8.0	1.0175	Greenbank 275kV
Molendinar (2T)	275	40.0	5.0	2.1	8.2	8.1	8.2	8.0	8.2	8.0	1.0176	Greenbank 275kV
Molendinar	110	31.5	11.9	10.2	19.3	24.4	19.2	24.2	19.2	24.3	1.0199	Greenbank 275kV
Mt England	275	40.0	9.1	8.3	22.9	23.1	22.9	23.0	23.0	23.1	1.0072	Greenbank 275kV
Mudgeeraba	275	40.0	5.4	4.3	9.3	8.6	9.2	8.6	9.3	8.6	1.0143	Greenbank 275kV
Mudgeeraba	110	31.5	11.0	10.0	17.4	21.0	17.2	21.1	17.3	21.2	1.0233	Greenbank 275kV
Murarrie (1T)	275	40.0	6.8	2.3	13.2	13.2	13.2	13.1	14.4	16.3	1.0092	Greenbank 275kV
Murarrie (2T)	275	40.0	6.8	2.3	13.2	13.4	13.1	13.3	14.4	16.3	1.0092	Greenbank 275kV
Murarrie	110	31.5	13.9	12.7	23.8	28.9	23.7	28.7	23.8	29.3	1.0164	Greenbank 275kV
Oakey	110	31.5	4.8	3.4	11.0	12.2	11.4	12.4	11.5	12.4	1.0941	Greenbank 275kV
Oakey GT	110	31.5	4.6	1.3	9.9	9.9	10.2	10.0	10.2	10.0	1.0994	Greenbank 275kV
Orana	275	40.0	6.2	3.2	16.5	15.9	16.6	16.1	16.6	16.1	1.0072	Western Downs 275kV
Palmwoods	275	40.0	5.7	3.5	8.7	9.1	8.8	9.1	8.8	9.2	1.0299	Greenbank 275kV
Palmwoods	132	31.5	9.3	6.9	13.3	16.1	13.4	16.1	13.4	16.2	1.0402	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
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	13.0	9.6	21.4	20.6	21.3	20.5	21.3	20.6	1.0207	Greenbank 275kV
Richlands	110	31.5	13.3	11.0	21.9	22.6	21.8	22.5	21.9	22.5	1.0202	Greenbank 275kV
Rocklea (1T)	275	40.0	7.0	2.3	13.3	12.3	13.2	12.3	13.3	12.3	1.0122	Greenbank 275kV
Rocklea (2T)	275	40.0	5.5	2.3	8.8	8.4	8.8	8.4	8.8	8.4	1.0235	Greenbank 275kV
Rocklea	110	31.5	14.7	12.9	25.0	28.8	24.9	28.6	25.0	28.7	1.0180	Greenbank 275kV
Runcorn	110	31.5	11.9	8.6	18.8	19.2	18.7	19.1	18.8	19.2	1.0237	Greenbank 275kV
South Pine	275	40.0	8.9	8.1	19.1	21.6	19.1	21.5	19.2	21.6	1.0099	Greenbank 275kV
South Pine (East)	110	31.5	13.7	11.6	21.7	27.8	21.7	27.7	21.8	27.8	1.0253	Greenbank 275kV
South Pine (West)	110	31.5	12.9	10.2	20.5	23.6	20.4	23.5	20.5	23.6	1.0249	Greenbank 275kV
Sumner	110	31.5	12.8	9.1	20.7	20.2	20.6	20.1	20.6	20.2	1.0226	Greenbank 275kV
Swanbank E	275	40.0	8.6	7.3	21.0	23.3	20.9	23.2	21.1	23.3	1.0017	Greenbank 275kV
Tangkam	110	31.5	5.6	3.8	13.0	12.1	13.8	12.4	13.8	12.4	1.0788	Greenbank 275kV
Tarong	275	40.0	12.3	10.5	34.6	37.0	34.1	36.6	34.6	37.0	1.0111	Western Downs 275kV
Tarong (1T)	132	31.5	4.5	1.1	5.8	6.1	-	-	-	-	1.0900	Western Downs 275kV
Tarong	66	31.5	12.5	7.1	15.5	16.6	15.4	16.5	15.5	16.6	1.0642	Western Downs 275kV
Teebar Creek	275	40.0	5.1	2.7	7.4	7.1	7.6	7.3	7.7	7.3	1.0317	Gin Gin 275kV
Teebar Creek	132	31.5	7.8	5.5	10.5	11.4	11.0	11.8	11.2	12.0	1.0446	Gin Gin 275kV
Tennyson	110	31.5	10.8	1.8	16.3	16.4	16.2	16.3	16.2	16.4	1.0309	Greenbank 275kV
Tummaville	330	50.0	6.2	5.8	-	-	16.5	16.6	16.6	16.7	1.0194	Western Downs 275kV
Upper Kedron	110	31.5	13.2	11.4	21.3	18.7	21.2	18.6	21.3	18.7	1.0227	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 2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)	2025/26 3 phase (kA)	2025/26 L – G (kA)	SSLF	Ref Node
Wandoan South	275	40.0	4.0	3.1	8.3	9.4	8.3	9.4	8.3	9.4	1.0267	Western Downs 275kV
Wandoan South	132	31.5	5.7	4.3	10.3	13.2	10.4	13.3	10.4	13.4	1.0507	Western Downs 275kV
West Darra	110	31.5	14.5	13.3	24.9	23.8	24.8	23.7	24.9	23.8	1.0173	Greenbank 275kV
Western Downs	275	40.0	7.8	5.4	27.9	30.0	28.0	30.4	28.1	30.5	1.0000	Western Downs 275kV
Woolooga	275	40.0	6.6	5.6	10.5	12.0	10.7	12.2	10.9	12.3	1.0220	Gin Gin 275kV
Woolooga	132	31.5	9.6	7.8	14.8	18.2	15.2	18.6	15.3	18.7	1.0369	Gin Gin 275kV
Yuleba North	275	40.0	3.5	2.8	6.5	7.1	6.5	7.1	6.5	7.1	1.0344	Western Downs 275kV
Yuleba North	132	31.5	5.2	4.0	8.3	10.0	8.3	10.0	8.3	10.0	1.0585	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
ARENA	Australian Renewable Energy Agency
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
DCA	Dedicated Connection Assets
DEPW	Department of Energy and Public Works
DNSP	Distribution Network Service Provider
DSM	Demand side management
EFCS	Emergency Frequency Control Schemes
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FIA	Full Impact Assessment
FNQ	Far North Queensland
GPS	Gladstone Power Station
GPSRR	General Power System Risk Review
IAM	Institute of Asset Management
IBR	Inverter-based Resources
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolts
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
NIEIR	National Institute of Economic and Industry Research
NSCAS	Nework Support and Control Ancillary Service
NSW	New South Wales
NQ	North Queensland
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

Appendix I - Glossary (continued)

PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
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
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCR	Short Circuit Ratio
SDA	State Development Area
SEQ	South East Queensland
SPS	Special Protection Scheme
SSSP	System Strength Service Provider
SSUP	System Strength Unit Prices
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condenser
TAPR	Transmission Annual Planning Report
TGCP	TAPR Guideline Connection Point
TGTL	TAPR Guideline Transmission Line
TNSP	Transmission Network Service Provider
TWh	Terawatt hour
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable renewable energy
VTL	Virtual transmission line
WAMPAC	Wide area monitoring protection and control