Appendices

Appendices

Appendix A Forecast of connection point maximum demands

Appendix A 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 A.1)
- a description of high, most likely and low growth scenarios (refer to Section A.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 A.3).

A.1 Forecasting methodology used by Energex and Ergon Energy (part of the Energy Queensland Group) for maximum demand

Energex and Ergon Energy 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 Energex and Ergon Energy's 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. Forecasts from the National Institute of Economic and Industry Research (NIEIR) and Deloitte Access Economics are also utilised.

The methodology used to develop the system demand forecast as recommended by consultants ACIL Tasman, is as follows:

Ergon

- Develop a six region based forecast within the Ergon network, with the aggregation at the distribution system peak time to provide a system peak 50% PoE. Each regional forecast uses a multiple regression equation to determine the relationship between demand and Gross State Product (GSP), maximum temperature, minimum temperature, total electricity price, a structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from November to March with days which fall below 28.5°C excluded from the analysis.
- A Monte-Carlo process is used across the South East Queensland (SEQ) and regional models to simulate a distribution of summer maximum demands using the latest 20 years of summer temperatures and an independent 10-year gross GSP forecast.
- Using the 30 top summer maximum demands from the simulation, produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.
- A stochastic term is applied to the simulated demands based on a random normal 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 the expected impact of rooftop PV, battery storage and electric vehicles (EV) based on the maximum demand daily load profile and anticipated usage patterns.

[1] Where applicable, Clauses 5.12.2(c)(iii) and (iv) are discussed in Chapter 2.

Energex

- Uses a multiple regression equation for the relationship between demand and GSP, square of weighted maximum temperature, weighted minimum temperature, total electricity price, structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from November to March, with the temperature data excluding days where the weather station's temperatures are below set levels (for example, Amberley mean temperatures < 22.7°C and daily maximum temperature < 30°C). 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.
- A Monte-Carlo process is used to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures and an independent ten-year GSP forecast.
- Using the 30 top summer maximum demands, produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.
- 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 EV based on the maximum demand daily load profile and anticipated usage patterns.

A.2 Description of Energex's and Ergon Energy'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 2020 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in June 2020 are based on these assumptions. In the forecasting methodology high, medium and low scenarios refer to maximum demand rather than the underlying drivers or independent variables. This avoids the ambiguity on both high and low meaning, as there are negative relationships between the maximum demand and some of the drivers e.g. high demand normally corresponds to low battery installations.

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 50MW of block loads incorporated in the system model over the forecast horizon.

At the zone substation level, Energy Queensland is currently tracking around 40MW of block loads for Ergon, and 70 MW for Energex. However, only the block loads which have a significant influence on the zone substation's peak demand are incorporated.

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 (3.3% per annum, not COVID-19 adjusted).
- Total real electricity price – Affects MW demand negatively, so the 'low' case of annual price changes is assumed to be 1% lower than the base case (compounded and Consumer Price Index (CPI) adjusted).
- Queensland population – The same start value as the base case in 2020, then follow the down-up trend before stabilising at around 1.8% by 2031.
- Rooftop PV – Lack of incentives for customers who lost the feed-in tariff (FIT) tariffs, plus slow falls in battery prices which discourage PV installations. Capacity may reach 3,159 MW by 2031.
- Battery storage – Prices fall slowly, battery safety remains an issue, and kW demand based network tariff is not introduced. Peak time (negative) contribution will reach 79 MW by 2031.
- EV – Significant fall in EV prices, 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 233 MW by 2031.
- Weather – follow the recent 30-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.2% per annum over the next 11 years – not COVID-19 adjusted).
- Total real electricity price – The medium case of annual price change of 0.6%.
- Queensland population – Grew 1.7% in 2019, and is expected to maintain at 1.5% in 2020 (partially affected by the COVID-19 pandemic), down to 0.6% (COVID-19 adjusted), before bouncing back to 1.2% in 2021, and gradually stabilising at around 1.4% by 2031 (based on the Deloitte's April 2020 forecasts).
- Rooftop PV – Invertor capacity will increase from 1,959 MW (February 2020) to 3,667 MW (February 2031);
- Battery storage – Peak time (negative) contribution will have a slow start of around 4 MW in 2020, but will gradually accelerate to 182 MW by 2031.
- EV – Stagnant in the short-term, boom in the long-term. Peak time contribution will only amount to 1.0 MW in 2020, but will reach 195 MW by 2031. Note however, EV will also have a significant impact on GWh energy sales.
- Weather – follow the recent 30-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – The 'low' case GSP growth (1.3% per annum, not COVID-19 adjusted).
- Total real electricity price – The 'high' case of annual price changes is assumed to be 1% higher than the base case (compounded and CPI adjusted) values.
- Queensland population – The same start value as the base case in 2020, weak GDP growth plus loss in productivity may slow population growth to 1.0% by 2031.
- Solar PV – Strong incentives for customers who lost the FIT tariffs, plus fast falls in battery prices encourage more PV installations. Capacity may reach 4,183 MW by 2031.
- Battery storage – Prices fall quickly, no battery safety issues, and kW demand based network tariff is introduced. Peak time (negative) contribution may reach a high at 308 MW by 2031.
- EV – Slow fall in EV prices, hard to find charging stations, charging time remaining long, still having basic features, less type sections, plus cheap petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 110 MW by 2031.
- Weather – follow the recent 30-year trend.

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, 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 (adjusted to 3.3% per annum over the next 11 years). Queensland population – growth of 0.6% pa to 2021, progressively increasing to 1.2% in 2021 and maintaining a level of approximately 1.5% by 2030.
- Rooftop PV – numbers and capacity monitored and estimated.
- Battery storage – numbers and capacity monitored and estimated.
- EV – numbers and capacity monitored and estimated.
- Weather – follow the recent trend of 20 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – the 'medium' case of GSP growth (adjusted to 2.2% per annum over the next 11 years).

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – the 'low' growth case of GSP growth (adjusted to 1.3% per annum over the next 11 years).

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

Major differences between the 2020 forecast and the 2019 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 EV has increased especially in the second half of the 2020 forecast when compared to the 2019 forecast. This, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

Energex connection points with the greatest difference in growth between the 2020 and 2019 forecasts are:

Connection Point	Change in growth rate
Blackstone 110kV	1.3% pa
Goodna 33kV	1.1% pa
Abermain 110kV	1.0% pa
Ashgrove West 110kV	-1.1% pa

Ergon connection points with the greatest difference in growth between the 2020 and 2019 forecasts are:

Connection Point	Change in growth rate
Moranbah 132kV	3.2% pa
Moranbah 66kV	1.5% pa
Newlands 66kV	-1.1% pa
Tangkam 110kV	-1.7% pa
Ross (Kidston and Millchester) 132kV	-2.7% pa

A.4 Customer forecasts of connection point maximum demands

Tables A.1 to A.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 A.2). These forecasts have been supplied by Powerlink customers.

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

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

In tables A.1 to A.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 B TAPR templates

In accordance with Clause 5.14B.1(a) of the National Electricity Rules (NER), the Australian Energy Regulator (AER)'s 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 templates may be directly accessed on Powerlink's website[2]. Alternatively please contact NetworkAssessments@powerlink.com.au for assistance.

For consistency with the TAPR document, the TAPR templates are able to filtered by Powerlink's geographical zones and outlook period, as well as the AER TAPR Guidelines template type (transmission connection point / line segment / new generator connection).

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 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.

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).

1 First published in December 2018.
2 Refer to the Resources tab on the TAPR website page.
3 Separate to the publication of the TAPR document which occurs annually.

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% PoE maximum demand, MVA[4] (TGCP008)
- Minimum demand, MVA[4] (TGCP008)
- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011)

Powerlink's in-house load profiling tool, incorporates a base year (1 October 2018 to 1 October 2019) 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 roof-top photovoltaic (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 2019 (the previous revision of those listed in Appendix A).

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 roof-top 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.

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

Table B.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. Please refer to Chapter 5 and/or Appendix F 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 5.4.
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 2017 to December 2019.
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 C Zone and grid section definitions

This appendix provides definitions of illustrations of the 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR).

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

Figures C.1 and C.2 provide illustrations of the generation, load and grid section definitions.

Table C.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 C.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 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) Callide A into Gladstone South 132kV (2 circuits)
CQ-SQ	Wurdong to Teebar Creek 275kV (1 circuit) (2) 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) Tarong into Chinchilla 132kV (2 circuits)
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)

Notes:

(1) The grid sections defined are as illustrated in Figure C.2. 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.

(2) CQ-SQ cutset redefined following Rodds Bay Solar Farm connection in winter 2022. Wurdong to Teebar Creek 275kV becomes Rodds Bay to Teebar Creek 275kV.

Figure C.1 Generation and load legend

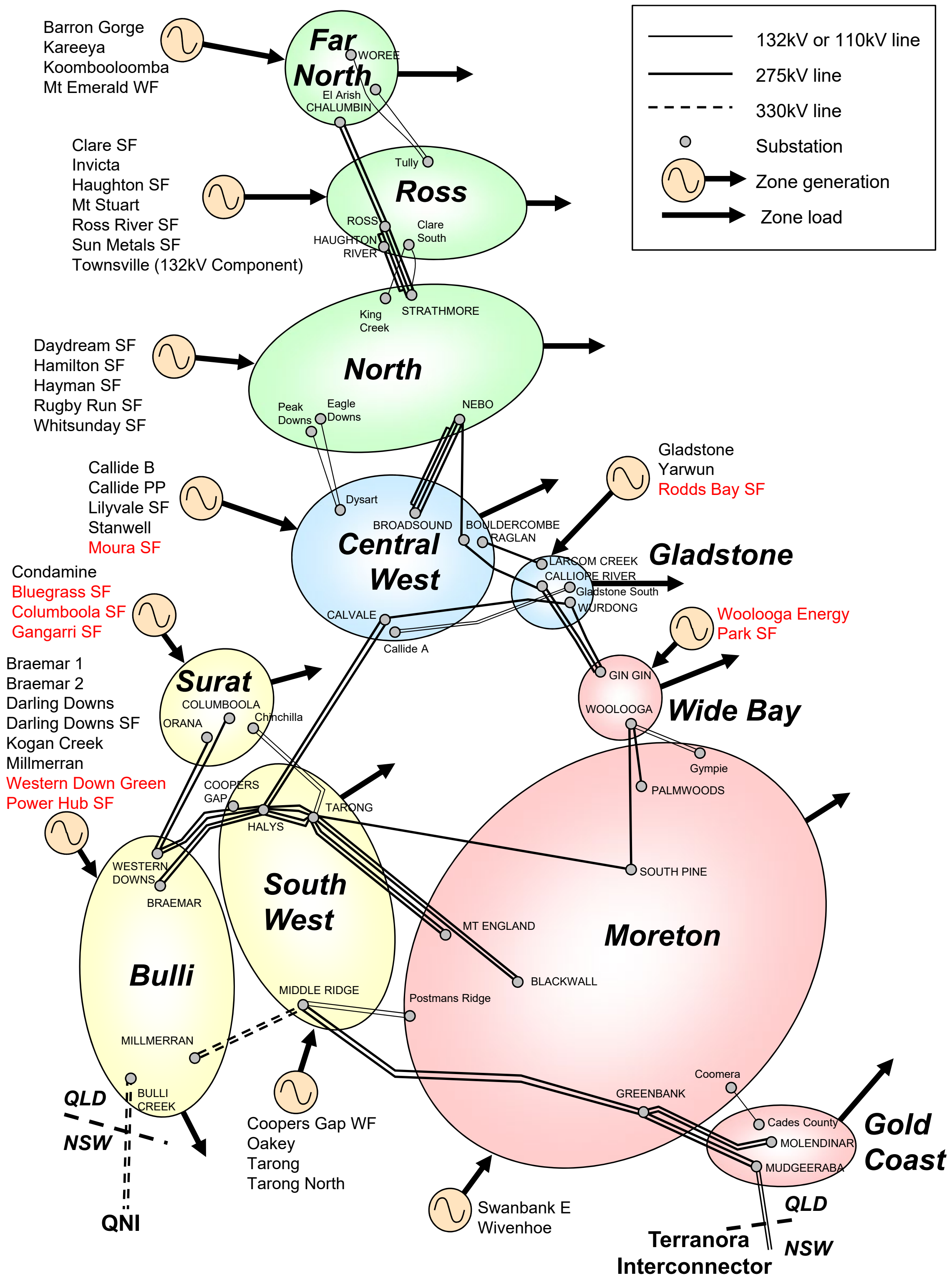
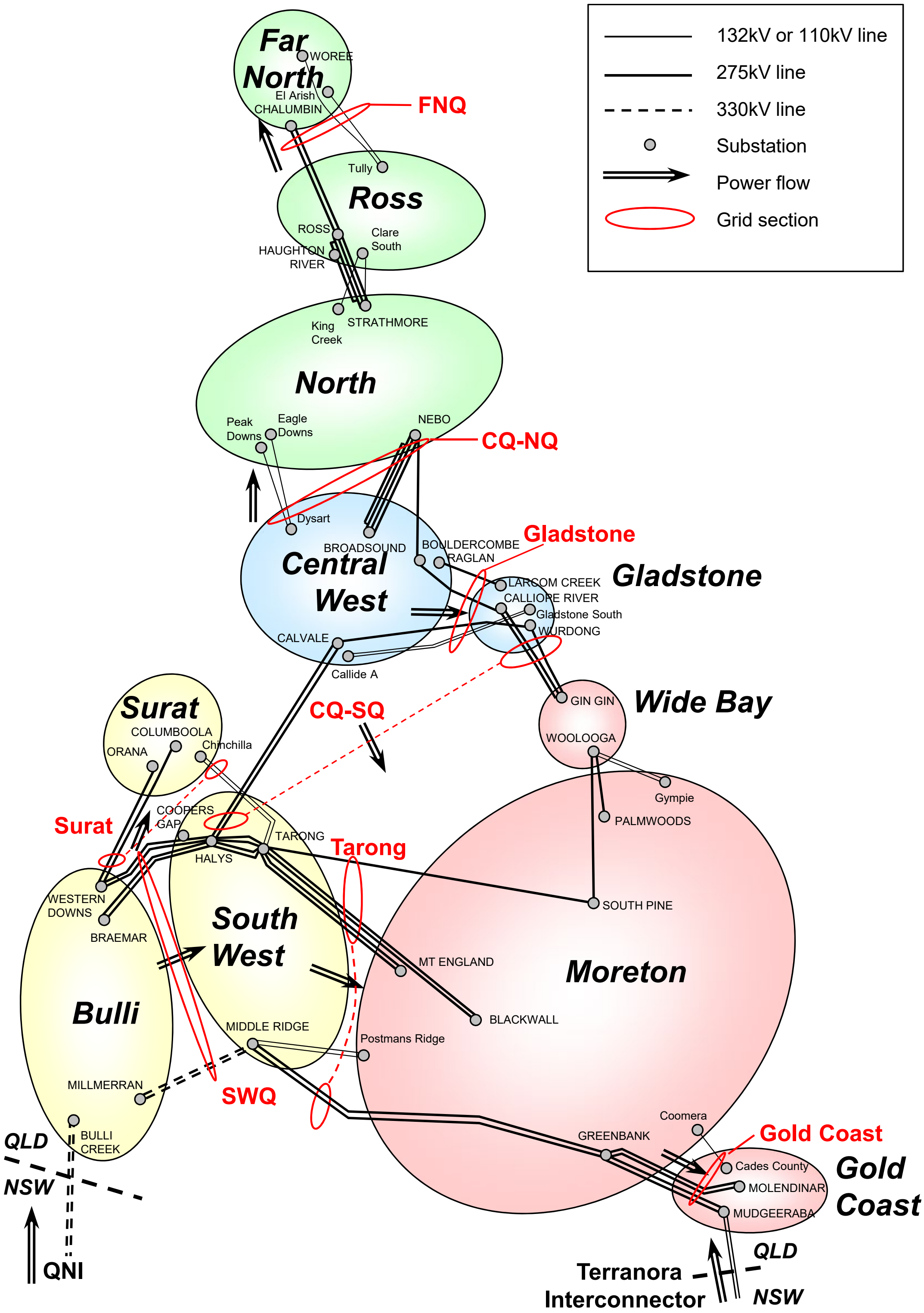


Figure C.2 Grid section legend



Appendix D Limit equations

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

It should be noted that 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 D.1 Far North Queensland (FNQ) grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	-19.00
FNQ demand percentage (1) (2)	17.00
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	-0.46
Total MW generation at Mt Stuart and Townsville	0.13
Total MW generation at Mt Emerald	-1.00
AEMO Constraint ID	Q^NIL_FNQ

Notes:

(1) FNQ demand percentage = $\frac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Mt Emerald Wind Farm) generation

NQ area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Mt Emerald Wind Farm + Townsville + Ross River Solar Farm + Haughton Solar Farm + Pioneer Mill + Mt Stuart + Sun Metals Solar Farm + Kidston Solar Farm + Kennedy Energy Park + Invicta Mill + Clare Solar Farm + Collinsville Solar Farm + Whitsunday Solar Farm + Hamilton Solar Farm + Hayman Solar Farm + Daydream Solar Farm + Mackay + Racecourse Mill + Moranbah + Moranbah North + Rugby Run Solar Farm) generation

(2) The FNQ demand percentage is bound between 22 and 31.

Table D.2 Central to NQ 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 generation at Mackay	-0.700	-0.478
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

Appendices

Notes:

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

(2) Northern VRE include:

Mt Emerald 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 D.3 describes three separate limit equations for the Mt Emerald Wind Farm, Sun Metals Solar Farm and Haughton Solar Farm. The Boolean AND operation is applied to the system conditions across a row, if the expression yields a True value then the maximum capacity quoted for the farm in question becomes an argument to a MAX function, if False then zero (0) becomes the argument to the MAX function. The maximum capacity is the result of the MAX function.

Table D.3 NQ system strength equations

Time of day (Day or Night) (1)	System Conditions										Maximum Capacity (MW)		
	Number of Gladstone units online	Number of Stanwell units online	Number of Callide B units online	Number of Callide C units online	Number of Callide units online (2)	Number of CQ units online (3)	Number of Kareeya units online	Number of Barron units online	NQ Load	Ross + FNQ Load	Mt Emerald WF	Sun Metals SF	Haughton SF
D	≥ 3	≥ 3			≥ 2	≥ 10	≥ 2	≥ 1	> 550	> 250	36	21.4	20
D	≥ 3	≥ 3			≥ 2	≥ 10	≥ 2	≥ 1	> 640	> 340	72	42.8	40
D	≥ 3	≥ 3			≥ 2	≥ 10	≥ 2	≥ 1	> 740	> 440	126	74.9	70
D	≥ 3	≥ 3	≥ 1	≥ 1		≥ 10	≥ 2	≥ 1	> 740	> 440	90	85.6	100
D	≥ 3	≥ 3			≥ 2	≥ 10	4	0	> 550	> 250	36	21.4	20
D	≥ 3	≥ 3			≥ 2	≥ 10	4	0	> 640	> 340	72	42.8	40
D	≥ 3	≥ 3			≥ 2	≥ 10	4	0	> 740	> 440	126	74.9	70
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	1	> 550	> 250	72	42.8	40
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	1	> 640	> 340	117	53.5	50
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	1	> 740	> 440	144	85.6	80
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	2	> 550	> 250	117	69.6	65
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	2	> 640	> 340	117	69.6	65
D/N	≥ 3	≥ 3			≥ 2	≥ 10	4	2	> 740	> 440	180	107	100
N	≥ 3	≥ 3			≥ 2	≥ 10			> 550	> 250	72	n/a	n/a
N	≥ 3	≥ 3			≥ 2	≥ 10			> 640	> 340	72	n/a	n/a
N	≥ 3	≥ 3			≥ 2	≥ 10			> 740	> 440	126	n/a	n/a
D	≥ 3	≥ 3	≥ 1	≥ 1		≥ 10			> 450	> 250	0	0	0
D			≥ 1	≥ 1		≥ 10		≥ 1	> 650	> 350	45	26.7	25
D/N	≥ 3	≥ 3			≥ 2	≥ 9	4	0	> 550	> 250	36	21.4	20

Table D.3 NQ system strength equations *(continued)*

Time of day (Day or Night) (1)	System Conditions										Maximum Capacity (MW)		
	Number of Gladstone units online	Number of Stanwell units online	Number of Callide B units online	Number of Callide C units online	Number of Callide units online (2)	Number of CQ units online (3)	Number of Kareeya units online	Number of Barron units online	NQ Load	Ross + FNQ Load	Mt Emerald WF	Sun Metals SF	Haughton SF
D/N	≥ 3	≥ 3			≥ 2	≥ 9	4	0	> 640	> 340	72	42.8	40
D/N	≥ 3	≥ 3			≥ 2	≥ 9	4	0	> 740	> 440	117	53.5	50
D/N	≥ 3	≥ 3	≥ 1	≥ 1		≥ 9	≥ 3		> 450	> 250	36	21.4	20
D/N	≥ 3	≥ 3	≥ 1	≥ 1		≥ 9	≥ 3		> 650	> 230	72	42.8	40
N	≥ 3	≥ 3	≥ 1	≥ 1		≥ 9			> 550	>3 50	0	n/a	n/a
N	≥ 3	≥ 3	≥ 1	≥ 1		≥ 9			> 650	> 350	72	n/a	n/a
D/N	≥ 3	≥ 2	≥ 1	≥ 1		≥ 8	≥ 3		> 450	> 250	36	21.4	20
D/N	≥ 3	≥ 2	≥ 1	≥ 1		≥ 8	≥ 3	≥ 1	> 450	> 250	72	42.8	40
N	≥ 3	≥ 2	≥ 1	≥ 1		≥ 8	≥ 3		> 450	> 250	36	21.4	20
N	≥ 3	≥ 2	≥ 1	≥ 1		≥ 8	≥ 3	≥ 1	> 450	> 250	72	42.8	40
D/N	≥ 3	≥ 2			≥ 1	≥ 7 and <10	≥ 2				0	0	0
D/N	≥ 3	≥ 2			≥ 1	≥ 7 and <10			> 450	> 250	0	0	0
D/N	≥ 3	≥ 2	≥ 1	≥ 1		≥ 8			> 450	> 250	0	0	0
AEMO Constraint ID											Q_NIL_STRGTH_MEWF	Q_NIL_STRGTH_SMSF	Q_NIL_STRGTH_HAUSF

Notes:

(1) 'Night' conditions refer to the total solar horizontal irradiance at Sun Metals, Haughton, Clare and Ross River < 4 and there are no inverters online at Sun Metals and Haughton.

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

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

System normal equations are implemented for all other north Queensland semi-scheduled generators (Ross River Solar Farm, Kidston Solar Farm, Clare 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 the last two conditions of Table D.3 where operation is constrained to 80%. Conditions resulting in lower synchronous unit capacity are constrained to 0.

Table D.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, 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 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 D.5 Tarong grid section voltage stability equations

Measured variable	Coefficient Equation 1 Calvale-Halys contingency	Coefficient Equation 2 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 (2)	-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, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Coopers Gap Wind Farm, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Millmerran and QNI transfers (positive transfer denotes northerly flow).

(3) There are currently 4 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 38 capacitor banks of nominal size 50MVAr which may be available within this area.

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

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 D.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 4 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 34 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix E Indicative short circuit currents

Tables E.1 to E.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations.

Indicative maximum short circuit currents

Tables E.1 to E.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2020/21, 2021/22 and 2022/23.

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 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 E.1 to E.3 are based on generation shown in tables 6.1 and 6.2 (together with any of the more significant embedded non-scheduled generators) and on the committed network development as at the end of each calendar year. The tables also show the rating of the lowest rated Powerlink owned plant at each location. No assessment has been made 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 (SVCs)). Minimum short circuit currents are also important in ensuring power system quality and stability and for ensuring the proper operation of protection systems.

Tables E.1 to E.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by analysing half hourly system normal snapshots over the period 1 July 2019 and 30 June 2020. The minimum of subtransient, transient and synchronous short circuit currents over the year were compiled for each substation, both for system normal and with the individual outage of each significant network element.

These minimum short circuit currents are indicative only, and as they are based on history are distinct from the minimum fault level published in the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls published by AEMO in July 2018.

Table E.1 Indicative short circuit currents – northern Queensland – 2020/21 to 2022/23

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2020/21		2021/22		2022/23	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.3	3.9	13.5	13.8	13.7	13.9	13.7	13.9
Alligator Creek	132	25.0	3.0	1.6	4.6	6.1	4.6	6.1	4.6	6.1
Bolingbroke	132	40.0	1.9	1.8	2.5	1.9	2.5	1.9	2.5	1.9
Bowen North	132	40.0	3.1	1.9	2.8	3.0	2.8	3.1	2.9	3.2
Cairns (2T)	132	25.0	2.8	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.8	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.8	0.7	5.9	7.8	5.9	7.9	-	-
Cardwell	132	19.3	1.9	0.9	3.1	3.3	3.1	3.3	3.1	3.3
Chalumbin	275	31.5	1.7	1.3	4.2	4.4	4.2	4.4	4.2	4.4
Chalumbin	132	31.5	3.1	2.4	6.5	7.5	6.6	7.6	6.6	7.6
Clare South	132	40.0	3.5	3.0	7.9	8.0	8.0	8.1	8.1	8.2
Collinsville North	132	31.5	4.6	2.3	8.7	9.6	8.8	9.7	11.3	12.2
Coppabella	132	31.5	2.0	1.3	3.1	3.4	3.1	3.4	3.1	3.4
Crush Creek	275	40.0	3.2	2.8	9.5	10.7	9.8	11.0	10.0	11.3
Dan Gleeson (1T)	132	31.5	4.3	3.7	12.8	13.2	13.0	13.3	13.0	13.3
Dan Gleeson (2T)	132	40.0	4.3	3.7	12.8	13.3	13.0	13.4	13.0	13.4
Edmonton	132	40.0	1.3	0.4	5.3	6.6	5.4	6.6	5.4	6.6
Eagle Downs	132	40.0	2.7	1.4	4.6	4.4	4.6	4.5	4.6	4.5
El Arish	132	40.0	2.0	0.9	3.3	4.0	3.3	4.0	3.3	4.0
Garbutt	132	40.0	4.0	1.8	11.1	11.0	11.2	11.0	11.2	11.0
Goonyella Riverside	132	40.0	3.2	2.8	5.9	5.4	5.9	5.4	6.0	5.5
Haughton River	275	40.0	2.6	2.1	7.2	7.2	7.7	8.0	7.8	8.0
Ingham South	132	31.5	1.9	0.9	3.3	3.4	3.3	3.4	3.3	3.4
Innisfail	132	40.0	1.9	1.2	3.0	3.6	3.0	3.6	3.0	3.6
Invicta	132	19.3	2.6	1.6	5.3	4.7	5.3	4.8	5.3	4.8
Kamerunga	132	15.3	2.3	0.5	4.5	5.4	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.7	2.2	5.6	6.3	5.6	6.3	5.6	6.3
Kemmis	132	31.5	3.8	1.5	6.1	6.6	6.1	6.7	6.1	6.7
King Creek	132	40.0	2.8	1.4	4.7	4.0	4.7	4.0	5.3	4.3
Lake Ross	132	31.5	4.9	4.4	17.7	19.7	18.0	20.0	18.0	20.0
Mackay	132	10.9	2.8	0.9	5.8	6.8	5.8	6.8	5.8	6.8

Table E.1 Indicative short circuit currents – northern Queensland – 2020/21 to 2022/23 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2020/21 3 phase (kA)	2020/21 L – G (kA)	2021/22 3 phase (kA)	2021/22 L – G (kA)	2022/23 3 phase (kA)	2022/23 L – G (kA)
Mackay Ports	132	40.0	2.4	1.5	3.5	4.2	3.5	4.2	3.5	4.2
Mindi	132	40.0	3.1	2.9	4.9	3.7	4.9	3.7	4.9	3.7
Moranbah	132	10.9	3.7	2.9	7.9	9.3	7.9	9.3	8.0	9.3
Moranbah Plains	132	40.0	2.1	1.8	4.4	4.0	4.4	4.0	4.4	4.0
Moranbah South	132	31.5	3.0	2.5	5.7	5.2	5.7	5.2	5.7	5.2
Mt Mclaren	132	31.5	1.5	1.3	2.1	2.3	2.1	2.3	2.1	2.3
Nebo	275	31.5	3.8	3.3	10.7	10.9	10.9	11.1	10.9	11.1
Nebo	132	25.0	6.4	5.6	13.9	15.9	14.1	16.0	14.1	16.0
Newlands	132	25.0	2.3	1.2	3.5	3.9	3.5	3.9	3.6	4.0
North Goonyella	132	20.0	2.7	0.9	4.4	3.7	4.5	3.7	4.5	3.7
Oonooie	132	31.5	2.2	1.3	3.2	3.7	3.2	3.7	3.2	3.7
Peak Downs	132	31.5	2.5	1.4	4.2	3.7	4.2	3.7	4.2	3.7
Pioneer Valley	132	31.5	4.0	3.4	7.2	8.0	7.2	8.0	7.2	8.0
Proserpine	132	40.0	2.2	1.5	3.2	3.8	3.3	3.8	3.5	4.1
Ross	275	31.5	2.7	2.4	8.6	9.6	9.0	10.0	9.0	10.0
Ross	132	31.5	4.9	4.4	18.2	20.5	18.6	20.9	18.6	20.9
Springlands	132	40.0	4.9	2.4	9.6	10.7	9.7	10.8	11.5	12.8
Stony Creek	132	40.0	2.4	1.1	3.6	3.5	3.6	3.6	3.8	3.7
Strathmore	275	31.5	3.2	2.8	9.6	10.8	9.9	11.1	10.1	11.5
Strathmore (1T)	132	40.0	5.0	2.4	9.8	11.2	9.9	11.3	11.8	13.5
Townsville East	132	40.0	4.1	1.6	13.1	12.6	13.2	12.7	13.2	12.7
Townsville South	132	21.9	4.5	4.1	17.8	21.4	18.1	21.6	18.1	21.6
Townsville GT PS	132	31.5	3.7	2.4	10.7	11.2	10.8	11.3	10.8	11.3
Tully	132	31.5	2.4	1.9	4.0	4.2	4.1	4.2	4.1	4.2
Turkinje	132	20.0	1.7	1.1	2.7	3.1	2.7	3.1	2.7	3.1
Walkamin	275	40.0	1.5	0.9	3.2	3.7	3.2	3.7	3.2	3.7
Wandoo	132	31.5	3.1	2.9	4.5	3.3	4.6	3.3	4.6	3.3
Woree (1T)	275	40.0	1.4	0.9	2.8	3.2	2.8	3.3	2.8	3.3
Woree (2T)	275	40.0	1.4	0.9	2.8	3.3	2.9	3.4	2.9	3.4
Woree	132	40.0	2.9	2.4	6.1	8.4	6.1	8.4	6.1	8.4
Wotonga	132	40.0	3.3	1.4	6.2	7.2	6.2	7.2	6.2	7.2
Yabulu South	132	40.0	4.2	3.8	12.8	12.1	13.0	12.2	13.0	12.2

Table E.2 Indicative short circuit currents – CQ – 2020/21 to 2022/23

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2020/21		2021/22		2022/23	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Baralaba	132	15.3	3.4	2.4	4.2	3.6	4.4	3.7	4.4	3.7
Biloela	132	20.0	3.8	1.0	7.8	8.1	8.1	8.3	8.1	8.3
Blackwater	132	10.9	3.9	3.4	5.9	7.1	5.9	7.1	5.9	7.0
Bluff	132	40.0	2.5	2.3	3.5	4.3	3.5	4.3	3.5	4.3
Bouldercombe	275	31.5	6.4	5.8	20.3	19.6	20.5	19.8	20.5	19.8
Bouldercombe	132	21.8	7.7	4.3	11.5	13.6	14.4	16.8	14.4	16.8
Broadsound	275	31.5	4.8	4.1	12.3	9.3	12.5	9.4	12.5	9.4
Bundoora	132	31.5	2.5	0.8	9.2	8.9	9.3	9.1	9.3	9.0
Callemondah	132	31.5	9.6	5.3	22.1	24.7	22.4	24.9	22.4	24.9
Calliope River	275	40.0	6.5	5.9	20.9	23.7	21.5	24.4	21.5	24.5
Calliope River	132	40.0	10.1	8.5	24.7	29.8	25.1	30.2	25.1	30.2
Calvale	275	31.5	7.1	6.1	23.5	26.0	23.8	26.2	23.8	26.2
Calvale (1T)	132	31.5	7.5	4.5	8.7	9.6	8.9	9.8	8.9	9.8
Calvale (2T)	132	40.0	7.4	4.5	8.4	9.3	8.6	9.4	8.6	9.4
Duaringa	132	40.0	1.7	0.9	2.3	2.9	2.3	2.9	2.3	2.9
Dysart	132	10.9	2.8	1.6	4.8	5.4	4.8	5.4	4.8	5.4
Egans Hill	132	25.0	5.3	1.4	7.2	7.4	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	6.3	5.7	19.4	21.6	20.0	22.2	20.0	22.2
Gladstone PS	132	40.0	9.2	7.9	21.8	25.0	22.0	25.2	22.0	25.2
Gladstone South	132	40.0	8.1	6.8	16.2	17.2	16.4	17.3	16.4	17.3
Grantleigh	132	31.5	2.1	1.7	2.6	2.7	2.7	2.8	2.7	2.8
Gregory	132	31.5	5.4	4.4	10.2	11.3	10.3	11.6	10.3	11.5
Larcom Creek	275	40.0	5.8	3.0	15.5	15.3	15.7	15.5	15.7	15.5
Larcom Creek	132	40.0	6.4	3.7	12.3	13.8	12.4	13.8	12.4	13.8
Lilyvale	275	31.5	3.2	2.5	6.3	6.0	6.3	6.2	6.3	6.1
Lilyvale	132	25.0	5.6	4.6	10.8	12.3	10.9	12.8	10.8	12.6
Moura	132	40.0	2.9	1.6	3.9	4.2	4.4	4.6	4.4	4.6
Norwich Park	132	31.5	2.3	1.0	3.7	2.7	3.7	2.7	3.7	2.7
Pandoin	132	40.0	4.6	1.1	6.2	5.5	6.9	6.0	6.9	6.0
Raglan	275	40.0	5.4	3.7	12.0	10.4	12.1	10.5	12.1	10.5
Rockhampton (1T)	132	40.0	4.4	1.6	5.8	5.9	6.4	6.3	6.4	6.3
Rockhampton (5T)	132	40.0	4.3	1.6	5.6	5.7	6.2	6.1	6.2	6.1

Table E.2 Indicative short circuit currents – CQ – 2020/21 to 2022/23 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2020/21 3 phase (kA)	2020/21 L – G (kA)	2021/22 3 phase (kA)	2021/22 L – G (kA)	2022/23 3 phase (kA)	2022/23 L – G (kA)
Rocklands	132	31.5	5.0	3.3	6.8	6.1	7.7	6.6	7.7	6.6
Stanwell	275	31.5	6.6	5.9	23.1	24.5	23.3	24.8	23.3	24.8
Stanwell	132	31.5	4.1	2.8	5.4	6.0	5.9	6.4	5.9	6.4
Wurdong	275	31.5	6.1	5.0	16.7	16.6	17.4	17.6	17.4	17.6
Wycarbah	132	40.0	3.2	2.4	4.2	5.1	4.5	5.4	4.5	5.4
Yarwun	132	40.0	6.3	4.1	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2020/21 to 2022/23

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2020/21		2021/22		2022/23	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	6.3	5.3	18.2	18.7	18.3	18.8	18.3	18.8
Abermain	110	31.5	11.6	9.6	21.5	24.5	21.5	24.5	21.5	24.5
Algester	110	40.0	11.7	10.6	21.0	20.8	21.1	20.9	21.1	20.9
Ashgrove West	110	26.3	11.0	8.8	19.1	20.1	19.2	20.1	19.2	20.1
Belmont	275	31.5	6.2	5.6	16.9	17.8	17.1	17.9	17.1	17.9
Belmont	110	37.4	13.9	12.8	27.7	34.4	27.9	34.5	27.9	34.5
Blackstone	275	40.0	6.5	5.9	21.2	23.3	21.4	23.4	21.4	23.4
Blackstone	110	40.0	12.7	11.7	25.4	27.9	25.5	28.0	25.5	28.0
Blackwall	275	37.0	6.7	6.0	22.4	24.1	22.7	24.3	22.7	24.3
Blythdale	132	40.0	3.2	2.2	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	5.6	5.1	23.7	25.7	24.2	26.2	24.2	26.2
Braemar (East)	275	40.0	6.5	4.5	27.0	31.3	27.4	31.7	27.4	31.7
Braemar (West)	275	40.0	6.4	4.4	27.6	30.4	28.5	31.3	28.5	31.3
Bulli Creek	330	50.0	5.8	3.2	18.5	14.5	18.6	14.6	18.6	14.6
Bulli Creek	132	40.0	2.8	2.5	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	10.2	7.4	17.2	16.6	17.3	16.6	17.3	16.6
Chinchilla	132	25.0	4.9	3.9	8.2	7.9	8.7	8.4	8.7	8.4
Clifford Creek	132	40.0	4.1	3.4	5.7	5.2	5.8	5.2	5.8	5.2
Columboola	275	40.0	5.1	4.1	13.1	12.3	13.7	12.8	13.7	12.8
Columboola	132	25.0	7.4	5.0	17.4	20.3	18.3	21.2	18.3	21.2
Condabri North	132	40.0	6.5	5.0	13.9	12.9	14.5	13.2	14.5	13.2
Condabri Central	132	40.0	5.1	4.0	9.2	6.8	9.5	6.9	9.5	6.9
Condabri South	132	40.0	4.0	3.3	6.7	4.5	6.8	4.5	6.8	4.5
Coopers Gap	275	40.0	6.2	3.1	17.6	17.5	17.8	17.6	17.8	17.6
Dinoun South	132	40.0	4.6	3.7	6.5	6.8	6.7	6.9	6.7	6.9
Eurombah (1T)	275	40.0	2.8	1.1	4.4	4.6	4.5	4.7	4.5	4.7
Eurombah (2T)	275	40.0	2.8	1.1	4.3	4.6	4.3	4.6	4.3	4.6
Eurombah	132	40.0	4.7	3.5	6.9	8.5	7.1	8.6	7.1	8.6
Fairview	132	40.0	3.0	2.4	4.0	5.0	4.0	5.1	4.0	5.1
Fairview South	132	40.0	3.8	2.9	5.2	6.6	5.3	6.7	5.3	6.7
Gin Gin	275	14.5	5.4	4.9	9.2	8.6	9.5	8.8	9.5	8.8
Gin Gin	132	20.0	7.5	5.6	12.0	13.0	12.3	13.2	12.3	13.2

Table E.3 Indicative short circuit currents – southern Queensland – 2020/21 to 2022/23 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2020/21 3 phase (kA)	2020/21 L – G (kA)	2021/22 3 phase (kA)	2021/22 L – G (kA)	2022/23 3 phase (kA)	2022/23 L – G (kA)
Goodna	275	40.0	6.1	4.9	16.2	16.0	16.4	16.1	16.4	16.1
Goodna	110	40.0	12.7	11.5	25.4	27.5	25.5	27.6	25.5	27.6
Greenbank	275	40.0	6.5	5.8	20.5	22.5	20.6	22.6	20.6	22.6
Halys	275	50.0	7.5	6.7	32.6	28.2	33.1	28.5	33.1	28.5
Kumbarilla Park (1T)	275	40.0	5.7	1.6	16.8	16.2	16.8	16.2	16.8	16.2
Kumbarilla Park (2T)	275	40.0	5.7	1.6	16.7	16.1	16.9	16.2	16.9	16.2
Kumbarilla Park	132	40.0	7.7	5.2	13.2	15.2	13.2	15.2	13.2	15.2
Loganlea	275	40.0	5.9	5.2	15.0	15.4	15.0	15.4	15.0	15.4
Loganlea	110	31.5	12.5	11.4	22.7	27.3	22.8	27.3	22.8	27.3
Middle Ridge (4T)	330	50.0	5.1	3.1	12.8	12.3	12.8	12.4	12.8	12.4
Middle Ridge (5T)	330	50.0	5.0	3.1	13.1	12.8	13.2	12.8	13.2	12.8
Middle Ridge	275	31.5	6.4	5.7	18.3	18.4	18.4	18.5	18.4	18.5
Middle Ridge	110	18.3	9.6	8.1	21.7	25.6	21.7	25.6	21.7	25.6
Millmerran	330	40.0	5.6	4.9	18.6	19.8	18.7	19.9	18.7	19.9
Molendinar (1T)	275	40.0	4.5	2.0	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar (2T)	275	40.0	4.5	2.0	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar	110	40.0	11.3	10.1	20.1	25.3	20.1	25.4	20.1	25.4
Mt England	275	31.5	6.6	6.1	22.7	22.9	23.0	23.1	23.0	23.1
Mudgeeraba	275	31.5	4.9	4.1	9.5	9.4	9.5	9.4	9.5	9.4
Mudgeeraba	110	25.0	10.8	10.0	18.7	22.9	18.8	22.9	18.8	22.9
Murarrie (1T)	275	40.0	5.7	2.4	13.2	13.2	13.3	13.2	13.3	13.2
Murarrie (2T)	275	40.0	5.7	2.4	13.2	13.3	13.2	13.3	13.2	13.3
Murarrie	110	40.0	12.7	11.5	23.8	28.7	23.8	28.8	23.8	28.8
Oakey Gt	110	31.5	4.7	1.1	11.4	12.5	11.4	12.5	11.4	12.5
Oakey	110	40.0	4.5	1.1	10.2	10.1	10.2	10.1	10.2	10.1
Orana	275	40.0	5.4	3.2	15.3	14.0	15.9	14.6	15.9	14.6
Palmwoods	275	31.5	4.9	3.2	8.5	9.0	8.8	9.2	8.8	9.2
Palmwoods	132	21.9	6.6	5.3	13.1	15.8	13.5	16.2	13.5	16.2
Palmwoods (7T)	110	40.0	5.5	2.6	7.3	7.6	7.3	7.6	7.3	7.6
Palmwoods (8T)	110	40.0	5.5	2.6	7.3	7.6	7.3	7.6	7.3	7.6

Table E.3 Indicative short circuit currents – southern Queensland – 2020/21 to 2022/23 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2020/21		2021/22		2022/23	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Redbank Plains	110	31.5	11.5	8.9	21.3	20.6	21.4	20.7	21.4	20.7
Richlands	110	40.0	11.8	10.2	21.8	22.6	21.9	22.6	21.9	22.6
Rocklea (1T)	275	31.5	5.7	2.3	13.2	12.3	13.3	12.3	13.3	12.3
Rocklea (2T)	275	31.5	4.8	2.3	8.8	8.4	8.8	8.5	8.8	8.5
Rocklea	110	31.5	12.8	11.6	24.9	28.7	25.1	28.8	25.1	28.8
Runcorn	110	40.0	11.0	8.2	18.8	19.2	18.8	19.2	18.8	19.2
South Pine	275	31.5	6.5	5.9	18.8	21.3	19.2	21.6	19.2	21.6
South Pine (West)	110	40.0	11.2	9.5	20.5	23.5	20.6	23.6	20.6	23.6
South Pine (East)	110	40.0	11.6	10.2	21.6	27.6	21.8	27.9	21.8	27.9
Sumner	110	40.0	11.4	8.6	20.6	20.2	20.7	20.3	20.7	20.3
Swanbank E	275	40.0	6.5	5.8	20.8	22.7	21.0	22.8	21.0	22.8
Tangkam	110	31.5	5.5	3.5	13.5	12.5	13.5	12.5	13.5	12.5
Tarong	275	31.5	7.5	6.7	34.0	35.8	34.5	36.2	34.5	36.2
Tarong (1T)	132	25.0	4.4	1.0	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	31.5	4.5	1.0	5.8	6.1	5.8	6.1	5.8	6.1
Tarong	66	40.0	10.4	5.9	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	4.4	2.8	7.3	7.0	7.7	7.4	7.7	7.4
Teebar Creek	132	40.0	6.4	4.7	10.8	11.6	11.1	11.9	11.1	11.9
Tennyson	110	40.0	9.7	1.5	16.2	16.4	16.3	16.4	16.3	16.4
Upper Kedron	110	40.0	11.7	10.4	21.2	18.7	21.3	18.8	21.3	18.8
Wandoan South	275	40.0	3.9	3.1	7.4	8.2	7.8	8.5	7.8	8.5
Wandoan South	132	40.0	5.8	4.4	9.2	12.0	9.9	12.7	9.9	12.7
West Darra	110	40.0	12.6	11.5	24.9	23.8	25.0	23.9	25.0	23.9
Western Downs	275	40.0	6.3	4.8	25.9	25.2	27.4	28.6	27.4	28.6
Woolooga	275	31.5	5.2	4.5	10.0	11.2	10.8	12.2	10.8	12.2
Woolooga	132	25.0	8.4	6.9	13.4	15.7	15.2	18.4	15.2	18.4
Yuleba North	275	40.0	3.4	2.8	6.0	6.6	6.2	6.7	6.2	6.7
Yuleba North	132	40.0	5.2	4.1	7.8	9.5	8.0	9.7	8.0	9.7

Appendix F Compendium of potential non-network solution opportunities within the next five years

Table F.1 Potential non-network solution opportunities within the next five years

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Transmission lines					
Woree to Kamerunga 132kV transmission line replacement	$40m	Far North	Up to 70MW at peak and up to 1,200MWh per day on a continuous basis to provide supply to the 22kV network	December 2026	Section 5.7.1
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations	$30 to $40m	Far North	Over 275MW at peak and up to 4,000MWh per day to provide supply to the Cairns area, facilitating the provision of system strength and voltage control	December 2024	Section 5.7.1
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations	$85 to $165m	Far North	Over 400MW at peak and up to 7,000MWh to provide supply to the Far North area, facilitating the provision of system strength and voltage control	December 2026	Section 5.7.1
Line refit works on the 275kV transmission line between Calliope River and Larcom Creek	$10m	Gladstone	Up to 160MW at peak and up to 3,200MWh per day on a continuous basis to provide supply to the 66kV and 132kV loads at Yarwun and Raglan	June 2024	Section 5.7.5
Line refit works on the 275kV transmission line between Wurdong and Boyne	$7m	Gladstone	Up to 400MW at peak and up to 10,000MWh per day on a continuous basis to supply the 275kV network at Boyne Island	December 2024	Section 5.7.5
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	$17m	Gladstone	Up to 160MW and up to 1,820MWh per day	December 2023	Section 5.7.5
Rebuild of two of the three transmission lines between Calliope River and Wurdong tee as a double circuit	$27m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional impacts and other impacts.	June 2024	Section 5.7.6
Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Tee	$6m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional and other impacts.	June 2026	Section 5.7.6

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	$20m to $30m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional other impacts.	June 2026	Section 5.7.6
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	$13m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2026	Section 5.7.10
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	$30m to $50m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	December 2028	Section 5.7.11
Substations - primary plant and secondary systems (excluding transformers)					
Innisfail 132kV secondary systems replacement	$11m	Far North	Up to 30MW at peak and 560MWh per day on a continuous basis to provide supply to the 22kV network at Innisfail	December 2024	Section 5.7.1
Chalumbin 132kV secondary systems replacement	$5m	Far North	Up to 400MW at peak and up to 7,000MWh per day on a continuous basis to supply the 275kV network	December 2025	Section 5.7.1
Edmonton 132kV secondary systems replacement	$6m	Far North	Up to 55MW at peak and up to 770MWh per day on a continuous basis to provide supply to the 22kV network at Edmonton	June 2026	Section 5.7.1
Ingham South 132kV secondary systems replacement	$6m	Ross	Up to 20MW at peak and up to 280MWh per day on a continuous basis to provide supply to the 66kV network at Ingham South	June 2025	Section 5.7.2
Alan Sherriff 132kV secondary systems replacement	$11m	Ross	Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kV network in north-east Townsville	June 2025	Section 5.7.2
Strathmore SVC secondary systems replacement	$6m	Ross	Up to 150MVArs capacitive and 80MVArs inductive dynamic voltage support at Strathmore	June 2026	Section 5.7.2

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Broadsound 150MVAr 300kV bus reactor	$9m	Central West	Equivalent to the proposed reactor at or near Nebo or Broadsound, being 126MVAr at the 275kV bus on a continuous basis and not coupled to generation output.	June 2023	Section 5.7.4
Callemondah Substation primary plant and secondary systems replacement	$7m	Central West	Up to 180MW at peak and up to 2,500MWh per day on a continuous basis to provide supply to the 132kV network at Gladstone South and/or Aurizon load at Callemondah	June 2024	Section 5.7.4
Network reconfiguration by replacement of the two 275/66kV transformers at Tarong Substation	$16m	South West	Up to 50MW and up to 850MWh per day on a continuous basis	June 2024	Section 5.7.7
Transformer ending Chinchilla substation from Columboola substation	$8m	South West	Up to 25MW at peak and up to 400MWh per day on a continuous basis	June 2024	Section 5.7.7
Chinchilla 132kV primary plant and secondary systems replacement	$8m	South West	Up to 25MW at peak and up to 400MWh per day on a continuous basis	June 2024	Section 5.7.7
One bus reactor each at Woolooga, Blackstone and Greenbank substations	$27m	Moreton	Additional voltage control equivalent to the proposed reactors at various locations in south east Queensland on a continuous basis	December 2023	Section 5.7.10
Murarrie 110kV secondary systems replacement	$21m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into the CBD and south-eastern suburbs of Brisbane of over 300MW	June 2025	Section 5.7.10
Ashgrove West 110kV secondary systems replacement	$6m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2025	Section 5.7.10
Mudgeeraba 110kV secondary systems replacement	$11m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	December 2025	Section 5.7.11
Mudgeeraba 275 and 110kV primary plant replacement	$20m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	December 2025	Section 5.7.11

Table F.1 Potential non-network solution opportunities within the next five years *(continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Substations - transformers					
Tully 132/22kV transformer replacement	$5m	Far North	Up to 15MW at peak and up to 270MWh per day to provide supply to the 22kV network at Tully	June 2024	Section 5.7.1
Tarong 275/66kV transformers replacement	$16m	South West	Full network support – up to 50MW at peak and up to 850MWh per day on a continuous basis as well as auxiliary supply of up to 38MVA to Tarong Power Station Partial network support – replace the functionality of one of the existing transformers on a continuous basis	June 2024	Section 5.7.7
Redbank Plains 110kV primary plant and 110/11kV transformers replacement	$8m	Moreton	Provide support to the 11kV network of up to 25MW and up to 400MWh per day	June 2024	Section 5.7.10

Notes:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget. However material operational costs, which are required to meet the scope of a network option, are included in the overall cost of that network option as part of the RIT-T cost-benefit analysis. Therefore, in the RIT-T analysis, the total cost of the proposed option will include an additional $10 million to account for operational works for the retirement of the transmission line.

(2) More generally, TAPR template data associated with emerging constraints which may require future capital expenditure, including potential projects which fall below the RIT-T cost threshold, is available on Powerlink's website (refer to Appendix B, in particular transmission connection points and transmission line segments data templates).

Appendix G 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
CAA	Connection and Access Agreement
CBD	Central Business District
COVID-19	Coronavirus disease 2019
CPI	Consumer Price Index
CQ	Central Queensland
CQ-SQ	Central Queensland to South Queensland
CQ-NQ	Central Queensland to North Queensland
CSG	Coal seam gas
DCA	Dedicated Connection Assets
DER	Disbributed Energy Resources
DNRME	Deparment of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DSM	Demand side management
EFCS	Emergency Frequency Control Schemes
EII	Energy Infrastructure Investments
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunity
EV	Electric vehicles
FIA	Full Impact Assessment
FIT	Feed-in tariff
FNQ	Far North Queensland
GCG	Generation Capacity Guide
GFI	Grid forming inverter
GPS	Generator Performance Standards
GSP	Gross State Product
GWh	Gigawatt hour
HV	High Voltage
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovoltage
LTTW	Lightning Trip Time Window
MLF	Marginal Loss Factor
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
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
NSP	Network Service Provider
NSCAS	Nework Support and Control Ancillary Service
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
OFGS	Over Frequency Generation Shedding
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PIA	Preliminary impact assessment
PoE	Probability of Exceedance

Appendix G - Glossary *(continued)*

PS	Power Station
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QHES	Queensland Household Energy Survey
QNI	Queensland/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
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TGCP	TAPR Guideline Connection Point
TGTL	TAPR Guideline Transmission Line
TNSP	Transmission Network Service Provider
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 and control

Contact us

Registered office	33 Harold St Virginia Queensland 4014 Australia ABN 82 078 849 233
Postal address	PO Box 1193 Virginia Queensland 4014 Australia
Telephone	+61 7 3860 2111 (during business hours)
Email	pqenquiries@powerlink.com.au
Website	www.powerlink.com.au
Social media	