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).
- 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 A.4).

A.1 Forecasting methodology used by Ergon Energy and Energex (part of the Energy Queensland Group) 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 Distributed Energy Resource (DER) 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 include 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).

[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 Gross State Product (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).
- 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 electric vehicles (EV) based on the maximum demand daily load profile and anticipated usage patterns.

A.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 2022 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in July 2022 are based on these 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 50MW of block loads incorporated in the system model over the forecast horizon.

At the zone substation level, Energy Queensland is currently tracking around 126MW of block loads for Ergon, and 463 MW 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 83MW and for Energex 232MW.

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 (3.8% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – 1.9% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 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 (3.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – Actual 0.9% in 2021, and 1.4% annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 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 (2.1% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Queensland population – 1.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 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 National Institute of Economic and Industry Research (NIEIR) in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – The 'high' case of GSP growth (3.8% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Queensland population – 1.9% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 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 8,771MW by 2032.
- Battery storage – Peak time (negative) contribution may reach 154MW by 2032 (behind the meter).
- EV – Price parity with the ICE type vehicles achieved earlier (whereby > 50% car sales are EV), 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 1,112MW by 2032.
- Weather – follow the recent 10-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (3.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – Actual 0.9% in 2021, and 1.4% annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Rooftop Solar 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 7,729MW by 2032.
- Battery storage – Peak time (negative) contribution will have a slow start of around 9MW in 2023 but may reach 80MW by 2032 (behind the meter).
- EV – Stagnant in the short-term, boom in the long-term. Peak time contribution will only amount to 2 MW in 2023 but will reach 452MW by 2032. 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 (2.1% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Queensland population – 1.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Rooftop Solar 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 6,593MW by 2032.
- Battery storage – Peak time (negative) contribution may reach a high at 27MW in 2032 (behind the meter).
- EV – Price parity with the ICE type vehicles is achieved much later (whereby > 50% car sales are EV), 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 17MW in 2032.
- Weather – follow the recent 10-year trend.

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

Major differences between the 2022 forecast and the 2021 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 DER has increased for the 2022 forecast when compared to the 2021 forecast. 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.

Ergon connection points with the greatest difference in growth between the 2022 and 2021 forecasts are:

Connection Point	Change in growth rate
Turkinje 132kV	2.31% pa
Middle Ridge 110kV	1.36% pa
Woolooga 132kV	1.34% pa
Cairns 22kV	1.33% pa
Ingham 66kV	1.22% pa

Energex connection points with the greatest difference in growth between the 2022 and 2021 forecasts are:

Connection Point	Change in growth rate
Redbank Plains 11kV	2.58% pa

A.4 Significant differences to actual observations

The 2021/22 summer was relatively mild across large parts of Queensland when compared to recent seasons. This, combined with ongoing COVID impacts, natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2021 forecast values for 2021/22 and what was observed.

Ergon connection points with the greater than 10% absolute difference between the peak 2021/22 and corresponding base 2021 forecast for 2021/22 are:

Connection Point	2021/22 forecast peak	2021/22 actual peak	Difference
Blackwater	105	139	32%
Ross	44	52	18%
Kamerunga	56	65	16%
Egans Hill	54	62	15%
Rockhampton	98	110	13%
Cairns	53	60	12%
Alligator Creek	28	31	11%
Turkinje	22	24	11%
Townsville South	107	93	-13%
Bulli Creek	22	19	-14%
Garbutt	112	96	-14%
Townsville East	48	41	-15%
Oakey	23	19	-17%
Tangkam	40	33	-17%

Energex connection points with the greater than 10% absolute difference between the peak 2021/22 and corresponding base 2021 forecast for 2021/22 are:

Connection Point	2021/22 forecast peak	2021/22 actual peak	Difference
Abermain 110kV	76	66	-13%
Abermain 33kV	115	101	-12%
Ashgrove West	120	106	-12%
Redbank Plans	31	28	-10%

A.5 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 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 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's (AER) Transmission Annual Planning Report (TAPR) Guidelines[1] set out the required format of TAPRs, in particular the provision of TAPR templates to complement the TAPR document. The purpose of the TAPR templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are 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.

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 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 providers3. 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 focused 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 (TGCP)) and TGTLXXX (TAPR Guideline Transmission Line (TGTL)).

1 First published in December 2018.
2 Refer to the TAPR portal.
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% Probability of Exceedance (PoE) maximum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- Minimum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011).

Powerlink's in-house load profiling tool, incorporates a base year (1 October 2019 to 1 October 2020) 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 photovoltaic (PV), distribution connected PV solar farms, battery storage, electric vehicles (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 2020 (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 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 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 chapters 6 and 7 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 C 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 8.6 – 8.8).

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

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

Figure C.1 provides illustrations of the 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

Grid section (1)	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) 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)

Note:

(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.

Table C.3 Zone generation details

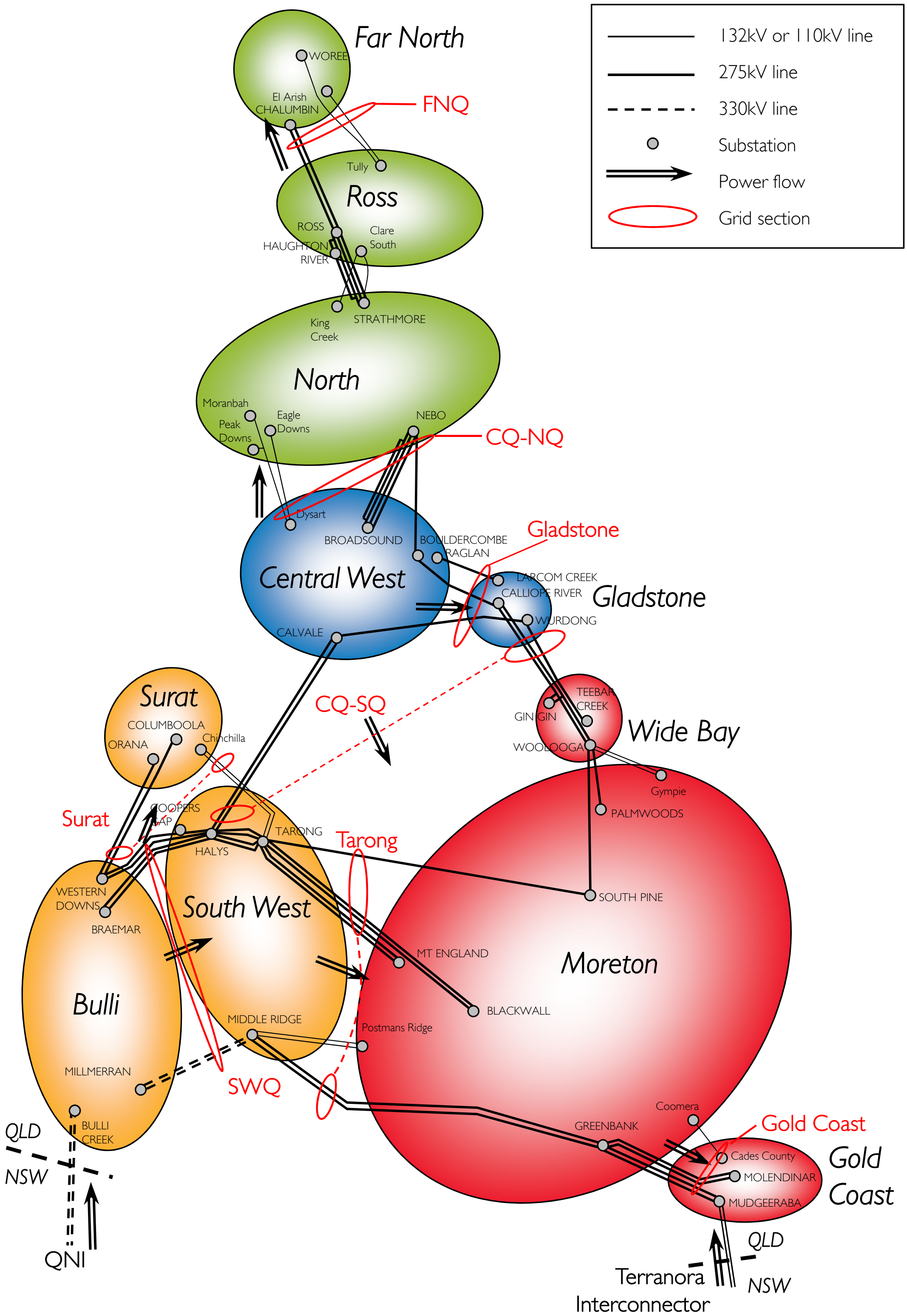
Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
Far North	Barron Gorge			•				
	Kareeya			•				
	Koombooloomba			•				
	Mt Emerald					•		
	Kaban (I)					•		
Ross	Townsville		•					
	Mt Stuart		•					
	Kidston (I)			•				
	Kidston				•			
	Clare				•			
	Haughton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

Table C.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		•					
	Coopers Gap					•		
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
Surat	Condamine		•					
	Columboola				•			
	Gangarri				•			
	Blue Grass				•			
	Edenvale (1)				•			
	Wandoan South (1)				•			
	Wandoan South						•	

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

Figure C.1 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 Australian Energy Market Operator (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	
	Equation 1	Equation 2
	Woree SVC	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	-025
Total MW generation at Mt Emerald 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_ WRSVC**	**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 capacitor bank 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 D.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient Equation 1 Feeder contingency	Coefficient Equation 2 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, Ross River Solar Farm, Sun Metals Solar Farm, Haughton Solar Farm, Clare Solar Farm, Kidston Solar Farm, Kennedy Energy Park, Collinsville Solar Farm, Whitsunday Solar Farm, Hamilton Solar Farm, Hayman Solar Farm, Daydream Solar Farm, Rugby Run Solar Farm
(3) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:
Ross 132kV 1 x 50MVAr
Townsville South 132kV 2 x 50MVAr
Dan Gleeson 66kV 2 x 24MVAr
Garbutt 66kV 2 x 15MVAr
(4) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:
Ross 275kV 2 x 84MVAr, 2 x 29.4MVAr
(5) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:
Newlands 132kV 1 x 25MVAr
Clare South 132kV 1 x 20MVAr
Collinsville North 132kV 1 x 20MVAr
(6) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:
Strathmore 275kV 1 x 84MVAr
(7) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:
Moranbah 132kV 1 x 52MVAr
Pioneer Valley 132kV 1 x 30MVAr
Kemmis 132kV 1 x 30MVAr
Dysart 132kV 2 x 25MVAr
Alligator Creek 132kV 1 x 20MVAr
Mackay 33kV 2 x 15MVAr
(8) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:
Nebo 275kV 1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr
(9) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:
Nebo 275kV 2 x 120MVAr

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

Table D.3 NQ system strength equations

System Conditions								Maximum Capacity (%)	
Number of Gladstone units online	Number of Stanwell units online	Number of Callide units online (1)	Number of CQ units online (2)	Number of Kareeya units online	NQ Load	Ross + FNQ Load	Haughton Synchronous Condensor Status	Haughton SF	Other NQ Plants
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 350	> 150	N/A	100	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 250	> 100	OFF	0	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 250	> 100	ON	100	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 0	> 350	> 150	OFF	50	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 0	> 350	> 150	ON	100	100
≥ 3	≥ 3	≥ 0	≥ 7	≥ 2	> 450	> 250	N/A	100	100
≥ 2	≥ 3	≥ 0	≥ 6	≥ 2	> 450	> 250	N/A	80	80
≥ 2	≥ 3	≥ 2	≥ 8	≥ 0	> 450	> 250	N/A	100	100
AEMO Constraint ID								Q_NIL_STRGTH_HAUSF	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_KIDSF, Q_NIL_STRGTH_MEWF, Q_NIL_STRGTH_RGBRSF, Q_NIL_STRGTH_RRUGSF, 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, 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 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, Columboola Solar Farm, Blue Grass Solar Farm, Western Downs Green Power Hub, Edenvale Solar Farm, Gangarri Solar Farm, Wandoan South Battery Energy Storage System, 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 D.5 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW in Surat, Bulli and South West and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	-0.8625	-0.7945
Total MW generation at Wivenhoe and Swanbank E	-0.0517	-0.0687
Active power transfer (MW) across Terranora Interconnector (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, 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 South Battery Energy Storage System, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryborough Solar Farm, Warwick Solar Farm, Blue Grass Solar Farm, Edenvale Solar Farm, Coopers Gap Wind Farm, Millmerran, and Queensland New South Wales Interconnector (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 2022/23, 2023/24 and 2024/25.

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, and
- 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 8.1 and 8.2 (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 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 taking the existing intact network and setting the synchronous generator dispatch to align with AEMO's assumptions for minimum three phase fault level. 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 2020 System Strength and Inertia Report published by AEMO in December 2020. However, small variations may exist between these two datasets due to variations in input data and modelling 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 (FIA) using Electromagnetic Transient-type (EMT-type) modelling techniques. See section 10.3 for full details.

Table E.1 Indicative short circuit currents – northern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.1	3.8	13.6	13.8	13.3	13.7	13.6	13.9
Alligator Creek	132	31.5	3.2	1.9	4.4	5.8	4.4	5.8	4.5	5.9
Aurumfield	275	40.0	1.3	0.8	-	-	-	-	3.7	4.7
Bolingbroke	132	40.0	2.0	1.9	2.5	1.9	2.5	1.9	2.5	1.9
Bowen North	132	40.0	2.5	1.6	3.0	3.2	3.0	3.2	3.0	3.2
Cairns (2T)	132	31.5	2.9	0.7	6.2	8.2	6.5	8.6	6.8	8.9
Cairns (3T)	132	31.5	2.9	0.7	6.2	8.1	6.5	8.5	6.8	8.9
Cairns (4T)	132	31.5	2.9	0.7	6.2	8.2	6.5	8.6	6.8	9.0
Cardwell	132	31.5	1.9	1.0	3.1	3.3	3.3	3.6	3.3	3.6
Chalumbin	275	31.5	1.8	0.7	4.5	4.9	4.8	5.2	5.3	5.6
Chalumbin	132	31.5	3.3	1.6	6.8	7.9	7.1	8.2	7.4	8.5
Clare South	132	31.5	3.3	2.8	8.1	8.2	6.6	6.8	6.6	6.9
Collinsville North	132	31.5	4.4	2.1	11.2	12.0	11.1	12.0	11.5	12.2
Coppabella	132	31.5	2.2	1.5	3.0	3.4	3.0	3.4	3.1	3.4
Crush Creek	275	40.0	3.5	3.1	9.9	11.3	10.0	11.4	10.7	11.9
Dan Gleeson (1T)	132	31.5	4.1	3.8	12.8	13.2	12.7	13.1	13.0	13.3
Dan Gleeson (2T)	132	31.5	4.1	3.8	12.8	13.3	12.7	13.2	13.0	13.4
Edmonton	132	31.5	1.3	0.4	5.6	6.8	5.9	7.1	6.1	7.3
Eagle Downs	132	31.5	3.0	1.5	4.6	4.4	4.6	4.5	4.6	4.5
El Arish	132	31.5	2.0	0.9	3.3	4.1	3.7	4.5	3.8	4.6
Garbutt	132	31.5	3.8	1.8	11.1	11.0	10.9	10.9	11.2	11.0
Greenland	132	31.5	3.5	2.1	-	-	5.5	5.0	5.6	5.0
Goonyella Riverside	132	31.5	3.5	1.5	6.0	5.5	6.0	5.5	6.1	5.5
Guybal Munjan	275	40.0	2.2	1.1	-	-	-	-	6.6	5.3
Haughton River	275	40.0	2.7	2.1	7.8	8.1	7.9	8.2	8.4	8.6
Ingham South	132	31.5	1.9	1.0	3.3	3.4	3.4	3.6	3.5	3.6
Innisfail	132	31.5	1.8	1.2	3.0	3.6	3.2	3.9	3.3	3.9
Invicta	132	19.3	2.5	2.4	5.3	4.8	5.2	4.8	5.2	4.8
Kamerunga	132	31.5	2.4	1.4	4.6	5.5	5.8	7.0	6.0	7.2
Kareeya	132	40.0	3.0	1.5	5.8	6.5	6.0	6.6	6.2	6.9
Kemmis	132	31.5	3.9	1.6	6.0	6.6	6.1	6.6	6.2	6.6
King Creek	132	31.5	2.8	2.0	5.4	4.4	5.3	4.3	5.3	4.4
Lake Ross	132	31.5	4.7	4.3	17.8	19.9	17.5	19.6	18.1	20.1
Mackay	132	31.5	3.5	2.9	5.0	6.0	5.0	6.0	5.1	6.1
Mackay Ports	132	31.5	2.6	1.6	3.4	4.1	3.4	4.1	3.5	4.1
Mindi	132	31.5	3.3	3.1	4.8	3.7	4.8	3.7	4.9	3.7

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

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Moranbah	132	31.5	4.1	3.3	7.9	9.4	7.9	9.4	8.1	9.4
Moranbah Plains	132	31.5	2.7	2.3	4.4	4.8	4.4	4.8	4.4	4.0
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.2	5.8	5.2
Mt Mclaren	132	31.5	1.6	1.4	2.1	2.3	2.1	2.3	2.1	2.3
Nebo	275	31.5	4.7	4.1	10.6	10.9	10.7	11.0	11.9	11.9
Nebo	132	31.5	7.3	6.4	13.4	15.4	13.4	15.5	14.2	16.2
Newlands	132	25.0	2.5	1.2	3.6	4.0	3.6	4.0	3.6	4.0
North Goonyella	132	31.5	2.9	1.4	4.5	3.7	4.5	3.7	4.6	3.8
Oonooie	132	31.5	2.4	1.5	3.1	3.6	3.1	3.6	3.1	3.7
Peak Downs	132	31.5	2.9	2.2	4.2	3.7	4.2	3.7	4.2	3.7
Pioneer Valley	132	31.5	4.2	3.6	6.5	7.4	6.5	7.4	6.6	7.5
Proserpine	132	31.5	2.0	1.3	3.5	4.0	3.5	4.0	3.5	4.1
Ross	275	40.0	2.8	2.5	9.0	10.0	9.2	10.5	10.2	11.3
Ross	132	40.0	4.7	4.3	18.4	20.7	18.0	20.3	18.8	21.0
Springlands	132	31.5	4.7	2.2	12.4	14.1	12.3	14.1	12.7	14.4
Stony Creek	132	31.5	2.5	1.1	3.8	3.7	3.8	3.7	3.8	3.7
Strathmore	275	40.0	3.6	3.1	10.0	11.4	10.1	11.5	10.8	12.1
Strathmore	132	40.0	4.8	2.2	12.8	15.0	12.7	15.0	13.1	15.4
Townsville East	132	31.5	3.9	1.5	12.9	12.5	12.7	12.4	12.9	12.6
Townsville South	132	31.5	4.2	3.9	17.5	21.1	17.0	20.5	17.4	20.9
Townsville GT PS	132	31.5	3.6	2.4	10.7	11.2	9.9	10.6	10.1	10.7
Tully	132	31.5	2.3	1.9	4.1	4.2	4.8	5.7	4.9	5.8
Tully South	275	40.0	1.7	1.4	-	-	3.7	4.0	3.9	4.1
Tumoulin	275	40.0	1.8	1.1	3.9	4.5	4.2	4.9	4.5	5.2
Turkinje	132	31.5	1.8	1.1	2.7	3.1	2.8	3.1	2.8	3.2
Walkamin	275	40.0	1.5	0.7	3.6	4.3	4.0	4.6	4.3	4.9
Wandoo	132	31.5	3.3	3.1	4.5	3.3	4.5	3.3	4.6	3.3
Woree (1T)	275	40.0	1.4	0.7	3.6	4.4	4.3	5.1	4.6	5.4
Woree (2T)	275	40.0	1.4	0.7	3.5	4.3	-	-	-	-
Woree	132	40.0	2.9	1.6	6.4	8.8	6.8	9.2	7.1	9.7
Wotonga	132	31.5	3.6	1.7	6.2	7.2	6.2	7.0	6.3	7.1
Yabulu South	132	40.0	4.0	3.7	12.9	12.2	11.0	11.0	11.3	11.1

Table E.2 Indicative short circuit currents – central Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)
Baralaba	132	31.5	3.9	2.5	4.3	3.7	4.4	3.8	4.4	3.8
Biloela	132	31.5	3.7	1.1	7.9	8.2	8.1	8.3	8.1	8.3
Blackwater	132	31.5	4.4	3.9	5.8	7.0	5.9	7.0	5.9	7.1
Bluff	132	31.5	2.8	2.6	3.5	4.3	3.5	4.2	3.5	4.2
Bouldercombe	275	40.0	10.8	9.3	19.8	19.4	20.5	19.9	21.6	20.5
Bouldercombe	132	40.0	9.1	4.8	14.5	16.7	14.7	16.9	14.8	17.1
Broadsound	275	40.0	6.3	5.1	12.1	9.3	12.4	9.4	15.3	16.2
Bundoora	132	31.5	5.5	4.7	9.1	8.8	9.2	9.0	9.4	9.2
Callemondah	132	31.5	17.2	6.7	22.0	24.6	22.1	24.7	22.2	24.8
Calliope River	275	40.0	12.2	10.5	20.8	23.7	21.1	24.3	21.4	24.6
Calliope River	132	40.0	19.0	15.6	24.6	29.7	24.8	29.9	25.0	30.1
Calvale	275	40.0	11.5	8.7	20.7	21.9	23.8	26.2	24.1	26.4
Calvale (1T)	132	40.0	5.6	1.0	8.7	9.5	8.9	9.8	8.9	9.8
Calvale (2T)	132	40.0	5.8	1.2	8.4	9.2	8.6	9.4	8.6	9.4
Duaringa	132	40.0	1.9	1.7	2.3	2.9	2.3	2.9	2.3	2.8
Dysart	132	25.0	3.2	1.9	4.8	5.3	4.8	5.4	4.8	5.4
Egans Hill	132	31.5	5.7	3.7	8.3	8.2	8.4	8.2	8.4	8.2
Gladstone PS	275	40.0	11.7	10.0	19.3	21.6	19.6	22.0	19.9	22.3
Gladstone PS	132	40.0	17.2	13.7	21.7	24.9	21.8	25.1	21.9	25.1
Gladstone South	132	40.0	12.8	9.6	16.2	17.2	16.2	17.3	16.3	17.3
Grantleigh	132	31.5	2.2	1.8	2.7	2.8	2.7	2.8	2.7	2.8
Gregory	132	31.5	6.0	5.0	10.0	11.2	10.2	11.4	10.5	11.8
Larcom Creek	275	40.0	9.5	3.3	15.4	15.2	15.6	16.6	15.8	16.7
Larcom Creek	132	40.0	7.7	4.0	12.3	13.8	12.3	14.0	12.4	14.0
Lilyvale	275	40.0	3.7	2.8	6.2	6.0	6.2	6.1	6.7	6.6
Lilyvale	132	31.5	6.2	5.1	10.6	12.2	10.7	12.4	11.1	13.0
Moura	132	31.5	3.2	1.7	4.3	5.3	4.4	5.4	4.4	5.4
Norwich Park	132	31.5	2.7	2.6	3.7	2.7	3.7	2.7	3.7	2.7
Pandoin	132	31.5	4.8	3.3	6.9	6.1	7.0	6.1	7.0	6.1
Raglan	275	40.0	7.9	4.4	11.8	10.4	12.0	10.7	12.2	10.8
Rockhampton (1T)	132	40.0	4.7	1.2	6.4	6.3	6.5	6.4	6.5	6.4
Rockhampton (5T)	132	40.0	4.5	1.3	6.2	6.1	6.3	6.2	6.3	6.2

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

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklands	132	31.5	5.6	3.6	7.7	6.6	7.8	6.6	7.8	6.6
Stanwell	275	31.5	11.6	9.6	22.3	24.0	23.3	24.8	24.6	25.8
Stanwell	132	31.5	4.5	3.2	5.9	6.4	6.0	6.4	6.0	6.4
Wurdong	275	31.5	10.7	6.7	16.5	16.5	16.8	16.8	17.0	16.9
Wycarbah	132	40.0	3.6	2.7	4.5	5.4	4.6	5.3	4.6	5.3
Yarwun	132	40.0	7.5	4.4	12.9	14.8	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)
Abermain	275	40.0	8.3	6.5	18.3	18.8	18.4	18.8	18.5	18.9
Abermain	110	40.0	13.1	10.4	21.5	24.5	21.6	24.5	21.6	24.6
Algester	110	31.5	13.2	11.8	21.1	20.9	21.2	20.9	21.2	20.9
Ashgrove West	110	31.5	12.4	9.4	19.2	20.1	19.2	19.6	19.2	19.6
Belmont	275	40.0	8.1	7.4	17.0	17.9	17.1	17.9	17.2	17.9
Belmont	110	40.0	16.0	15.0	27.8	34.5	27.9	34.4	28.0	34.5
Blackstone	275	40.0	8.9	8.1	21.4	23.4	21.5	23.6	21.6	23.6
Blackstone	110	40.0	14.8	13.6	25.5	27.9	25.6	28.0	25.6	28.1
Blackwall	275	40.0	9.5	8.6	22.7	24.3	22.8	24.4	22.9	24.5
Blythdale	132	40.0	3.2	2.3	4.3	5.3	4.3	5.4	4.3	5.4
Braemar	330	50.0	7.2	5.9	24.3	26.4	24.8	26.8	24.8	26.8
Braemar (West)	275	40.0	8.1	4.7	28.8	31.7	29.7	32.6	29.7	32.6
Braemar (East)	275	40.0	8.3	5.4	27.5	31.8	27.9	32.2	27.9	32.2
Bulli Creek	330	50.0	7.1	3.4	18.6	14.9	18.9	15.0	18.9	15.0
Bulli Creek	132	40.0	3.0	3.0	3.8	4.3	3.8	4.4	3.8	4.4
Bundamba	110	31.5	11.2	7.7	17.3	16.6	17.3	16.6	17.3	16.7
Cameby	132	31.5	5.2	4.2	11.0	9.7	11.1	9.7	11.1	9.7
Chinchilla	132	25.0	5.4	3.8	8.7	10.1	8.7	10.1	8.7	10.1
Clifford Creek	132	31.5	4.1	3.4	6.0	5.4	6.0	5.4	6.0	5.4
Columboola	275	40.0	5.6	4.3	14.2	13.4	14.5	13.6	14.5	13.6
Columboola	132	40.0	7.8	5.0	18.2	21.2	18.7	21.8	18.7	21.8
Condabri North	132	31.5	6.9	5.5	14.5	13.3	14.8	13.5	14.8	13.5
Condabri Central	132	31.5	5.4	4.5	9.5	7.0	9.6	7.0	9.6	7.0
Condabri South	132	31.5	4.4	3.7	6.8	4.6	6.9	4.6	6.9	4.6
Coopers Gap	275	40.0	8.3	3.2	18.0	17.8	18.2	18.0	18.3	18.0
Dinoun South	132	31.5	4.6	3.6	6.9	7.1	6.9	7.1	6.9	7.1
Eurombah (IT)	275	40.0	2.8	1.2	4.7	4.9	4.7	4.9	4.7	4.9
Eurombah	132	40.0	4.7	3.5	7.3	8.9	7.4	8.9	7.4	9.0
Fairview	132	31.5	3.0	2.5	4.1	5.2	4.1	5.2	4.1	5.2
Fairview South	132	40.0	3.8	2.9	5.4	6.9	5.5	6.9	5.5	6.9
Gin Gin	275	40.0	6.5	4.4	9.3	8.8	9.4	8.8	9.8	9.2
Gin Gin	132	40.0	8.0	6.0	12.2	13.1	12.2	13.1	13.0	14.1

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

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Goodna	275	40.0	8.0	5.6	16.3	16.1	16.4	16.1	16.5	16.1
Goodna	110	40.0	14.9	13.1	25.5	27.5	25.6	27.6	25.6	27.6
Greenbank	275	50.0	8.7	8.0	20.6	22.6	20.8	22.7	20.8	22.8
Hayls	275	50.0	12.1	10.4	33.3	28.6	34.0	29.2	34.0	29.3
Kumbarilla Park (2T)	275	40.0	6.8	1.7	16.9	16.2	17.1	16.4	17.1	16.4
Kumbarilla Park	132	40.0	8.4	5.6	13.2	15.3	13.3	15.3	13.3	15.3
Loganlea	275	40.0	7.5	6.2	15.0	15.4	15.1	15.5	15.1	15.5
Loganlea	110	40.0	13.6	12.2	22.7	27.3	22.8	27.3	22.9	27.4
Middle Ridge (4T)	330	50.0	5.9	3.2	12.8	12.3	12.9	12.4	12.9	12.4
Middle Ridge (5T)	330	50.0	6.0	3.2	13.2	12.8	13.3	12.8	13.3	12.9
Middle Ridge	275	31.5	7.8	6.9	18.4	18.4	18.5	18.6	18.5	18.6
Middle Ridge	110	31.5	10.8	8.9	21.5	25.3	21.6	25.4	21.6	25.5
Millmerran	330	40.0	6.5	6.1	18.7	19.9	18.8	20.1	18.8	20.1
Molendinar (1T)	275	40.0	5.1	2.1	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar (2T)	275	40.0	5.1	2.1	8.2	8.1	8.3	8.1	8.3	8.1
Molendinar	110	40.0	12.4	10.8	19.3	24.5	19.4	24.5	19.4	24.5
Mt England	275	31.5	9.4	8.5	23.0	23.1	23.2	23.2	23.2	23.3
Mudgeeraba	275	40.0	5.6	4.5	9.3	8.6	9.3	8.6	9.3	8.6
Mudgeeraba	110	40.0	11.8	10.9	17.4	21.1	17.4	21.1	17.5	21.1
Murarrie (1T)	275	40.0	7.0	2.3	13.2	13.2	13.3	13.2	13.3	13.2
Murarrie (2T)	275	40.0	7.0	2.3	13.2	13.3	13.3	13.3	13.3	13.4
Murarrie	110	40.0	14.2	13.1	23.8	28.9	23.9	28.8	23.9	28.8
Oakey GT	110	31.5	4.9	3.5	11.3	12.4	11.3	12.4	11.3	12.4
Oakey	110	31.5	4.6	1.3	10.1	10.0	10.2	10.1	10.2	10.1
Orana	275	40.0	6.3	3.3	16.5	16.5	17.0	16.5	17.0	16.6
Palmwoods	275	31.5	5.7	3.5	8.8	9.2	8.8	9.2	8.9	9.2
Palmwoods	132	31.5	8.0	6.1	13.4	16.1	13.4	16.2	13.5	16.2
Palmwoods (8T)	110	31.5	5.7	2.6	7.3	7.6	7.3	7.6	7.3	7.6
Redbank Plains	110	31.5	13.2	9.7	21.4	20.7	21.5	20.7	21.5	20.7
Richlands	110	31.5	13.5	11.2	21.9	22.6	22.0	22.6	22.0	22.6
Rocklea (1T)	275	31.5	7.1	2.3	13.3	12.3	13.4	12.4	13.4	12.4

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

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (2T)	275	31.5	5.5	2.3	8.8	8.4	8.8	8.5	8.9	8.5
Rocklea	110	31.5	14.9	13.1	25.1	28.8	25.1	28.7	25.2	28.8
Runcorn	110	31.5	12.2	8.7	18.8	19.2	18.9	19.2	18.9	19.3
South Pine	275	40.0	9.1	8.4	19.1	21.6	19.3	21.7	19.3	21.8
South Pine (West)	110	40.0	13.1	10.3	20.5	23.7	20.6	23.7	20.6	23.7
South Pine (East)	110	40.0	13.8	11.8	21.7	27.8	21.8	27.9	21.9	28.0
Sumner	110	31.5	13.0	9.2	20.7	20.3	20.8	19.6	20.8	19.7
Swanbank E	275	40.0	8.8	7.4	21.0	22.8	21.2	23.1	21.3	23.1
Tangkam	110	31.5	5.7	3.9	13.4	12.4	13.5	12.4	13.5	12.4
Tarong	275	40.0	12.6	10.7	34.7	36.3	35.4	37.7	35.5	37.7
Tarong (1T)	132	40.0	4.5	1.1	5.8	6.1	5.8	6.1	5.8	6.1
Tarong	66	40.0	11.5	6.7	15.5	16.6	15.5	16.6	15.5	16.6
Teebar Creek	275	40.0	5.1	2.4	7.6	7.2	7.6	7.2	7.7	7.3
Teebar Creek	132	40.0	7.4	4.5	11.0	11.8	11.0	11.8	11.2	11.9
Tennyson	110	31.5	10.7	9.8	16.3	16.4	16.3	16.4	16.3	16.4
Upper Kedron	110	40.0	13.4	11.6	21.3	18.8	21.4	18.6	21.4	18.6
Wandoan South	275	40.0	4.0	3.1	8.3	9.4	8.4	9.5	8.4	9.5
Wandoan South	132	40.0	5.7	4.4	10.3	13.2	10.4	13.3	10.4	13.3
West Darra	110	31.5	14.8	13.6	25.0	23.8	25.0	23.7	25.1	23.7
Western Downs	275	40.0	7.9	5.4	27.9	29.4	29.4	33.8	29.4	33.8
Woolooga	275	40.0	6.7	5.7	10.7	12.2	10.7	12.2	10.9	12.4
Woolooga	132	40.0	9.3	7.4	15.1	18.5	15.1	18.5	15.3	18.7
Yuleba North	275	40.0	3.5	2.8	6.5	7.1	6.6	7.2	6.6	7.2
Yuleba North	132	40.0	5.2	4.0	8.3	10.0	8.3	10.1	8.3	10.1

Appendix F 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
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
DEPW	Department of Energy and Public Works
DER	Disbributed Energy Resources
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 Opportunity
EV	Electric vehicle
FIA	Full Impact Assessment
FNQ	Far North Queensland
IAM	Institute of Asset Management
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
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
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PHES	Pumped Hydro Energy Storage
PoE	Probability of Exceedance
PS	Power Station
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic

Appendix G - Glossary (*continued*)

PVNSG	Photovoltaic non-scheduled generation
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QHES	Queensland Household Energy Survey
QNI	Queensland to New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
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
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
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