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 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 Exceedence (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 Australian Bureau of Statistics (ABS) data, Queensland Government data, the Australian Energy Market Operator (AEMO) data, the National Institute of Economic and Industry Research (NIEIR), Deloitte Access Economics, an independently produced Queensland air conditioning forecast, rooftop photo voltaic (PV) connection data and historical maximum demand data.

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

- Develop a multiple regression equation for the relationship between demand and Gross State Product (GSP), maximum temperature, minimum temperature, total electricity price, structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from December to February but excludes days where the average temperature at Amberley is <24.5°C. Other parameters such as customer behaviour patterns and demand management responses are also included. For the South East Queensland (SEQ) system model, three weather stations were incorporated into the model through a weighting system to capture the influence of the sea breeze on maximum demand. Statistical testing is applied to the model before its application to ensure that there is minimum bias in the model. For regional Queensland, up to five weather stations are chosen depending upon the significance tests undertaken each year.
- A Monte-Carlo process is used across the SEQ and regional models to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures and an independent 10-year gross GSP forecast and an independent air conditioning load forecast.
- Use the 30 top summer maximum demands to 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 electric vehicles (EVs) based on the maximum demand daily load profile and expected equipment usage patterns.

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

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 March 2017 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink at the end of 2017 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 correspond to low battery installations.

Block Loads

There are some block loads scheduled over the next 11 years. It is expected that Queensland Rail will undertake some projects which will either permanently or temporarily impact on the Energex system maximum demand. In regional Queensland, in excess of 50MW is expected in mining load over the next four years.

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:

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 medium case of GSP growth (2.7% per annum over the next 11 years).
- Total real electricity price – the low case of annual price change of -0.2% (compounded and consumer price index (CPI) adjusted).
- Queensland population – a relatively high growth of 1.68% in 2018 (driven by improved net immigration), slowing to 1.50% in 2024 before climbing back to 1.65% by 2028.
- Roof top PV – lack of incentives for customers who lost the feed-in tarriff (FIT) tariffs, plus slow falls in battery prices which discourage PV installations. Capacity may reach 2,246MW by 2028.
- Battery storage – prices fall slowly, battery safety remains an issue, and kW demand based network tariff is not introduced. Capacity gradually increase to 583MW by 2028.
- 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 exceed 350MW by 2028.
- Weather – follow the recent 30-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – the low case of GSP growth (1.6% per annum over the next 11 years).
- Total real electricity price – the medium case of annual price change of 0.1%.
- Queensland population – growth of 1.35% in 2016, increasing to 1.42% in 2017 before slowing down to 1.27% by 2028.
- Roof top PV – invertor capacity increasing from 1,184MW in 2017 to 2,974MW by 2028.
- Battery storage – capacity will have a slow start of around 2.6MW in 2017, but will gradually accelerate to 892MW by 2028.
- EV – Stagnant in the short term, boom in the long term. Peak time contribution (without diversity ratio adjusted) will only amount to 2.2MW in 2018, but will reach 232MW by 2028. Note however, EV will impact GWh energy sales more than the maximum demand, and up to 80% diversity ratios will be used in the charging period.
- Weather – follow the recent 30-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – the long-term variation adjusted low case GSP growth (0.6% per annum over the next 11 years)
- Total real electricity price – the high case of annual price change of 1.4%
- Queensland population – low growth of 1.2% in 2018 (due to adverse immigration policies), then weak gross domestic product (GDP) growth plus loss in productivity may slow growth to 0.9% by 2028
- Roof top PV – strong incentives for customers who lost the FIT tariffs, plus fast falls in battery prices which encourage more PV installations. Capacity may hit 3,927MW by 2028
- Battery storage – prices fall quickly, no battery safety issues, and a demand based network tariff is introduced. Capacity may reach a high at 1,252MW by 2028
- EV – slow fall in EV prices, hard to find charging stations, charging time remaining long, still having basic features, plus cheap petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 175MW by 2028
- Weather – follow the recent 30-year trend.

Summary of the Ergon model

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

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 – high growth average (3.4% per annum consistent with NIEIR's high growth average).
- Queensland population – growth of 1.35% in 2016, increasing to 1.42% in 2017 before slowing down to 1.27% by 2028.
- Roof top PV – numbers and capacity monitored and estimated.
- Battery storage – not used in the forecast baseline but inclusion as part of ongoing PV installations are closely monitored and reviewed.
- EV – not used in the forecast baseline but uptake within regional Queensland closely reviewed.
- Weather – follow the recent trend of at least 30 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – medium growth average (2.6% per annum consistent with NIEIR's medium growth agerage).

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – low growth average (1.5% per annum consisistent with NIEIR's low growth average).

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

The general trend in connection point maximum demand growth is flat or slightly declining. The main exceptions to this trend for SEQ are:

Connection Point	2016/17 Forecast	2015/16 Forecast
Abermain 33 CP	2.3% pa	0.9% pa
Belmont 110 CP	1.2% pa	0.7% pa
Goodna 33 CP	3.1% pa	2.9% pa
Redbank Plains 11 CP	2.0% pa	3.1% pa

The key reason for the changes is the underlying growth rates at the zone substations supplied from each connection point.

Ergon connection points are forecast over the next 10 years to be flat or slightly declining with the exception of load coming on from earlier mining activity.

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 – Powerlink's forecasting methodology

This appendix describes Powerlink's demand and energy forecasting methodology. Powerlink is publishing its forecasting model with the 2018 Transmission Annual Planning Report (TAPR), which should be reviewed in conjunction with this description.

Powerlink's forecasting methodology for energy, summer maximum demand and winter maximum demand comprises the following three steps:

1. Transmission customer forecasts

   The loads of customers other than Energex and Ergon Energy that connect directly to Powerlink's transmission network are assessed based on their forecasts, recent history and through direct consultation. Only committed load is included in the medium economic outlook forecast, while some speculative load is included in the high economic outlook forecast.

2. Econometric regressions

   Forecasts are developed for Energex and Ergon Energy based on relationships between past usage patterns and economic variables where reliable forecasts for these variables exist.

3. New technologies

   The impact of new technologies such as rooftop photo voltaic (PV), distribution connected solar and wind farms, battery storage, electric vehicles (EV) and demand side management (DSM) are factored into the forecasts for Energex and Ergon Energy.

The discussion below provides further insight to steps 2 and 3, where Distribution Network Service Provider (DNSP) forecasts are developed.

Econometric regressions

DNSP forecasts are prepared for summer maximum demand, winter maximum demand and annual energy.

To prepare these forecasts, regression analysis is carried out using native demand and energy plus distribution connected solar PV which includes rooftop PV and distribution connected solar and wind farms as this represents the total underlying Queensland DNSP load. This approach is necessary as the regression process needs to describe all electrical demand in Queensland, irrespective of the type or location of generation that supplies it.

Data preparation

To undertake weather correction and regression analysis the following historical native energy and maximum demand values need to be assembled. as follows:

- *Energy*

  Determine DNSP native energy for each year from 2000/01. As this work is performed in April, an estimation is prepared for the current financial year which will be updated with actual totals 12 months later when preparing the next TAPR.

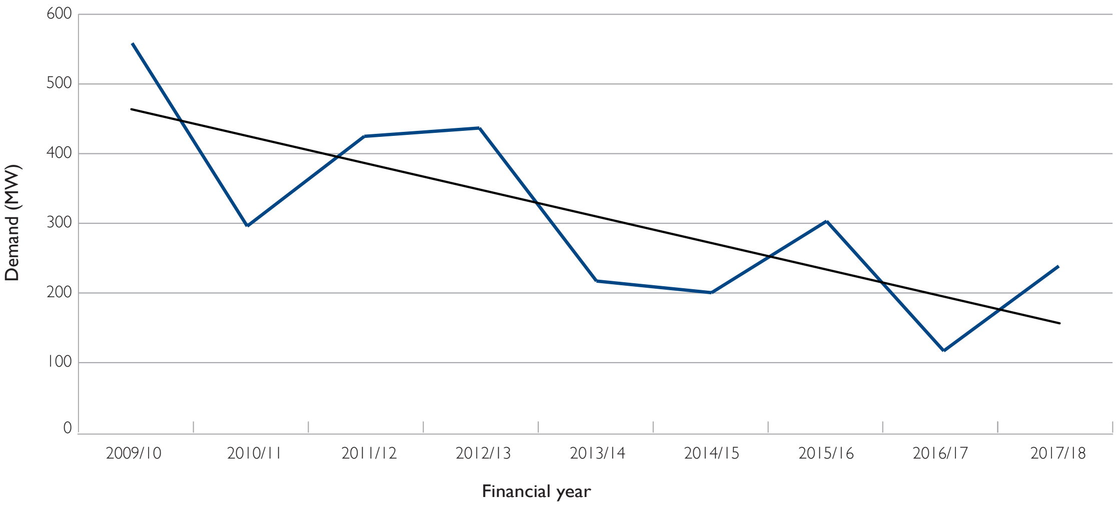
- *Winter maximum demand*

  The DNSP native demand at the time of winter state peak is collated for each year from winter 2000. Each of these demands are then normalised to average weather conditions (50% probability of exceedance (PoE)). Powerlink's method for weather correction is described later in this appendix.

- *Summer maximum demand*

  The DNSP native demand at the time of summer state peak is collated for each year from summer 2000/01. Each of these demands are then normalised to average weather conditions (50% PoE). DNSP native demand at the time of summer state evening peak (after 6pm) is also collated for each year from summer 2000/01. These demands are also corrected to average weather conditions. This evening series is used as the basis for regressing as evidence supports Queensland moving to a summer evening peak due to the increasing impact of rooftop PV and distribution connected solar farms. This move to an evening peak by 2022/23 is supported through analysis of day and evening trends for corrected maximum demand as illustrated in Figure B.1.

Figure B.1 Difference in summer day and summer evening normalised maximum demand



Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for existing rooftop PV and distribution connected solar farms. This ensures that the full underlying DNSP load is being regressed. This energy adjustment assumes that rooftop PV, on average, has a 14% capacity factor. This capacity factor is based on observations through the use of data sourced from the Australian PV Institute.

Following the regression for energy, the forecast is then adjusted to take into account future rooftop PV and distribution connected solar and wind farm contributions based on forecast capacity. Forecast summer maximum demand is now based on an evening regression adjusted for the transition to an evening peak. Winter maximum demand has historically occurred in the evening, so no adjustment needs to be applied.

Retail electricity price projections

Powerlink engaged an independent consultant to develop the Queensland retail electricity price projections for the 10-year forecast period for the 2018 TAPR. The price projection forecast includes a significant reduction over the next five years, which is much lower than the price projections assumed within the 2017 TAPR. The reduction in forecast retail price is attributed to the high quantities of renewable generation that have committed over the previous 12 months. The additional generation is expected to make the wholesale generation market within Queensland more competitive.

The demand and energy regression models have been modelled on flat retail electricity prices (2004/05 to 2006/07 and 2014/15 to 2017/18) and with rising retail electricity prices (2006/07 to 2014/15). The 14 years of historical data that defines the forecasting regression models, do not include any years where the retail electricity prices are falling. As a result there is no quantitative data on how the demand and energy will respond to falling electricity prices. Without intervention the impact on the regression models to falling prices will be the reverse of the damping effect that rising electricity prices have had on the demand and energy forecast in the past. However, it is expected that electricity consumers will generally maintain their energy efficiency behaviours, implying that there is an asymmetrical effect of rising and falling electricity prices on the demand and energy forecast.

Powerlink has explored the asymmetrical concept of electricity pricing with AEMO and some members of Powerlink's Customer Panel. Feedback from members of Powerlink's Customer Panel includes:

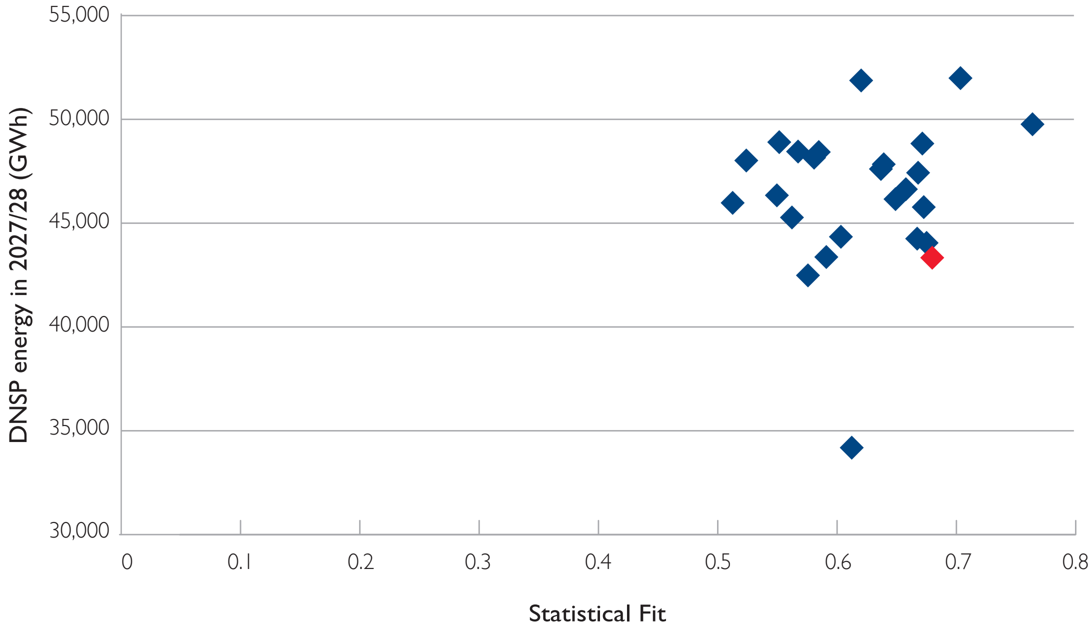
- Customers are conditioned to rising electricity prices and generally consumption is not expected to increase.
- Older consumers will continue with their current consumption patterns and won't change their behaviour, even if there is a significant reduction in prices. Reference was made to water saving programs in several jurisdictions e.g. Victoria, Queensland and Australian Capital Territory where consumers changed their consumption patterns permanently even after water restrictions were lifted.
- People on low incomes will not increase consumption and any savings will be used elsewhere.
- Consumers don't have confidence in energy companies. They won't trust that prices will stay down, and will be suspicious that there will be extraordinary price rises in subsequent years to make up for an initial price reduction. They will not feel sufficiently confident to change behaviour.
- Many consumers have put in place measures to reduce energy consumption, and these tend to be permanent in nature.
- Majority of people find it difficult to compare retail offers and 'crunch the numbers'.
- There is a lack of education on electricity billing and pricing.
- Business will react to electricity price changes before residential households.
- Both AEMO and Powerlink acknowledge the asymmetrical effects that rising and reducing retail electricity prices have on the demand and energy forecast. With falling electricity prices, lower income households (seniors, disadvantaged and vulnerable) are not expected to materially change their consumption behaviours, however more affluent households may slightly increase their consumption.

Energy regression

An energy regression is developed using historical energy data (described above) as the output variable and total retail electricity price and an economic variable for inputs. A logarithmic relationship between the input and output variables is used in keeping with statistical good practice in energy forecasting.

Input variables are the total retail electricity price and an economic variable selected from 16 economic variables (supplied by consultants). For each of these 16 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 64 regressions being assessed. Of these, the top 25 are selected and placed on a scatter plot as shown in Figure B.2 where the statistical fit and energy forecast at the end of the forecast period are assessed. The statistical fit combines several measures including R-squared, Durbin-Watson test for autocorrelation, mean absolute percentage error and mean bias percentage. All top 25 regressions shown in Figure B.2 qualify as statistically good regressions.

Figure B.2 Energy regression results



The selected regression shown above in red uses Queensland employment with no delay and total electricity price with a one year delay. The selected regression was chosen as it uses broad based input variables and reflects the expected outcome of asymmetrical pricing effects with reducing electricity prices. The 2017 TAPR energy regression used Queensland retail turn-over with no delay and total electricity price with a one year delay.

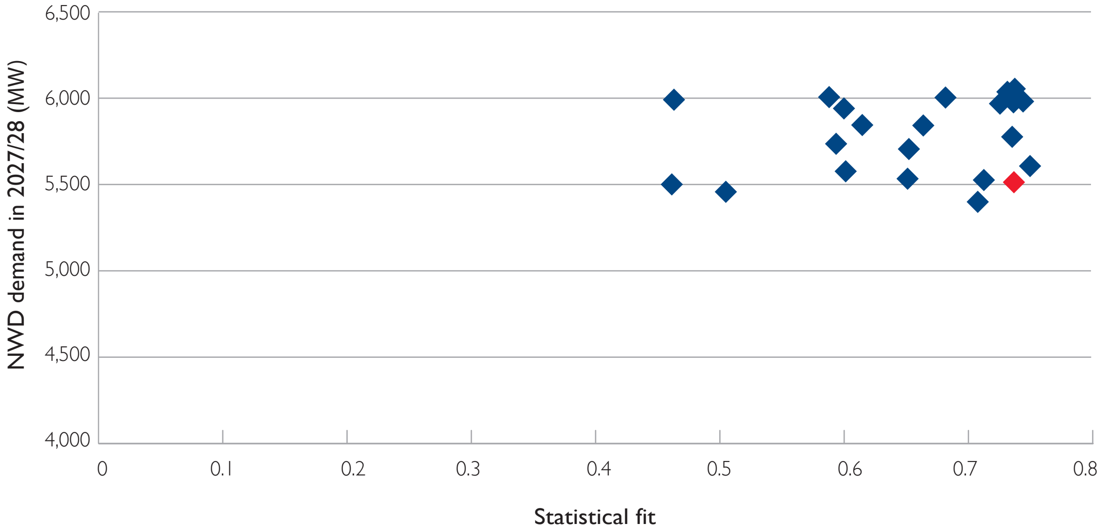
The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The temperature-normalised historical demands are split into two components: non-weather dependent (NWD) demand and weather dependent (WD) demand. NWD demand is determined as the median weekday maximum demand in the month of September. This reflects the low point in cooling and heating requirements for Queensland. The balance is the WD demand. For summer, this is the difference between the corrected summer maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected winter maximum demand and the NWD demand based on the following September.

The forecast NWD demand is therefore used for both the summer and winter maximum demand forecasts. The regression process used to determine the NWD demand is the same as used for energy with the results illustrated in Figure B.3.

Figure B.3 Non-weather dependent demand regression results

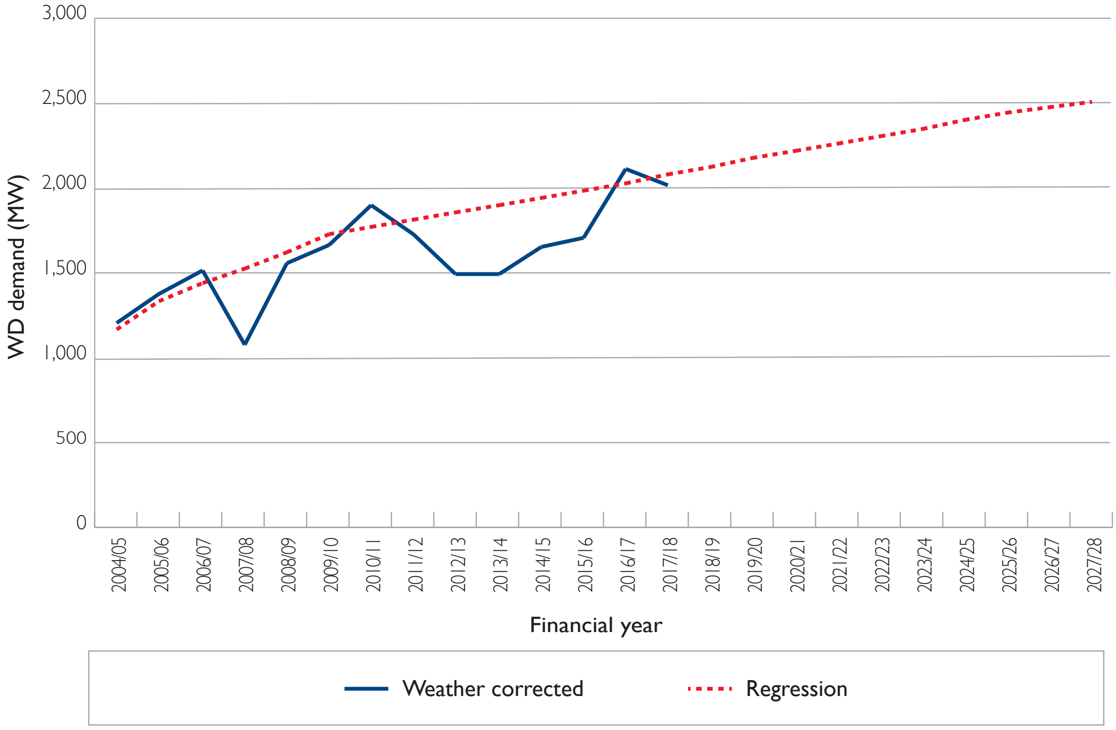


The selected regression shown above in red uses Queensland employment with no delay and total electricity price with a one year delay. The 2017 TAPR NWD regression used Queensland retail turnover and total electricity price both with a one year delay.

The summer and winter WD demand is mainly related to air conditioning usage. These regressions have been based on one input variable, the population multiplied by Queensland air conditioning penetration. Historical air conditioning penetration rates and consumer intensions to purchase air conditioners are provided annually in the Queensland Household Energy Survey (QHES).

The 2016/17 and 2017/18 summer WD demand was substantially higher than the previous four summers. A number of troughs for the summer WD demand have been recorded, these include summer 2007/08 and the period from 2011/12 to 2015/16. Summer 2007/08 aligns with the initial shock of the Global Financial Crisis (GFC) and the period from 2011/12 to 2015/16 aligns with high electricity price increases from about 2009. The QHES results indicate that households were more frugal in their electricity behaviours from 2011 to 2015 and that this behaviour has been tempered from 2016. The summer WD demand regression is illustrated in Figure B.4, with the years impacted by the GFC and high price increases removed from the regression.

Figure B.4 Weather dependent demand regression – summer



Similar to the energy analysis, low, medium and high economic outlook forecasts are produced for maximum demands by applying the appropriate economic forecasts as inputs. For maximum demand it is also necessary to provide three seasonal variation forecasts for each of these economic outlooks leading to nine forecasts in total. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

New technologies

Understanding the future impacts of new technologies is crucial to developing robust and meaningful demand and energy forecasts. Recognising the importance that these technologies will play in shaping future demand and energy, Powerlink is committed to furthering its understanding of these drivers. The new technologies discussed in this section are not incorporated within the energy regression and the summer and winter maximum demand regressions. To include these new technologies, post regression adjustments are made to the DNSP demand and energy forecasts. The new technology adjustments that Powerlink has adopted within the forecasts are summarised in Table B.1.

Table B.1 New technology assumptions

	Rooftop PV	Distribution connected solar and wind farms	Battery storage	Electric vehicles	Tariff reform/ DSM	Customer momentum
Energy (GWh) (1)	2,589	4,244	0	-311	0	1,804
Maximum demand (MW) (2)	0	0	16	0	180	215
Installed capacity in 2027/28 (MW)	4,175	1,583				
Installed capacity in 2027/28 (MWh)			74			
First year of impact	now	now	now	now	2020/21	2018/19

Notes:

(1) This is the energy reduction in financial year 2027/28 compared to 2017/18.

(2) This is the maximum demand reduction in summer 2027/28 compared to summer 2017/18.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow readers to substitute alternative assumptions into the forecast if desired.

Rooftop PV

The installed capacity of rooftop PV in Queensland as at the end of 2017 was in the order of 2,000MW. Growth in rooftop PV capacity has increased from around 15MW per month in 2016/17 to 25MW per month in 2017/18. However the forecast of reducing electricity prices will extend the payback period of new rooftop PV and this is expected to decrease the rate of new capacity over the forecasting period. New rooftop PV capacity is forecast to remain at 25MW per month in 2018/19 before reducing and remaining at 15MW per month from 2020/21.

Analysis has revealed that Queensland will move to a summer evening peak by 2022/23 and so further rooftop PV, which is predominantly installed facing north, is expected to have little impact on maximum demand after this time. Energy impacts have been based on an average output of 14% capacity.

Powerlink is a member of the Australian PV Institute which supplies real time data for rooftop PV. This information allows Powerlink to analyse a range of effects and in particular its impact on maximum demand.

Future impacts of rooftop PV will need to be monitored carefully. As older systems fail, they may be replaced with larger systems or not replaced at all. Furthermore, if enabling factors such as government incentives or rapid uptake of battery storage were to occur, then future rooftop PV installation levels could increase beyond this forecast.

Distribution connected solar farms

The federal government's large-scale renewable energy target (LRET) of 33,000GWh per annum by 2020 and the Queensland government's target of 50% renewable energy by 2030 are driving forecast increases of renewable generation connecting directly to the distribution networks. Previous TAPRs did not model the Queensland government's target of 50% renewable energy by 2030.

The energy forecast includes 654MW of committed semi-scheduled solar farms and 107MW of committed semi-scheduled wind farms to connect to the distribution networks. This is 75% of the committed renewable generation connecting to the distribution networks within Table 6.2. The energy forecast also includes 98MW of committed non-scheduled solar farms connecting to the distribution networks over the next two years.

Solar farms connecting directly to the distribution network will accelerate the delay of the state maximum demand from around 5:30pm to an evening peak.

Battery storage

Battery storage technology has the potential to significantly change electricity consumption patterns. In particular, this technology could 'flatten' electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks. By coupling this technology with rooftop PV, consumers may have the option to go 'off grid'. A number of factors will drive the uptake of this technology, namely:

- affordability
- retail electricity prices
- introduction of time of use tariffs
- continued uptake of rooftop PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

The 2017 QHES indicates that around 8% of Queensland households are considering the purchase of a battery storage system. However the same survey indicates that most people underestimate the current price of installing a storage solution.

The forecast of reducing electricity prices will extend the payback period of battery storage systems and delay the uptake of new systems. As a consequence, the forecast capacity of battery storage systems at the end of the 10-year forecasting period has been significantly reduced within the 2018 TAPR. Powerlink's methodology to estimate the uptake of battery storage and the impact on summer maximum demand involves the following steps:

1. Estimate the maximum population of residential battery storage systems, based on dwelling type, home ownership, and household income factors. This is estimated to be 400,000 households.
2. Bell curved the uptake of battery storage systems based on the financial payback period, with a mean of five years and a standard deviation of 1.75 years.
3. Calculate the pay-back period for a market leading battery storage system for each year in the 10-year outlook period. The installation price of future battery storage systems was estimated using CSIRO's battery cost path from their electricity network transformation roadmap interim program report.
4. From the bell curve of battery uptake (based on the financial payback period) and the calculated yearly payback period of a battery system, calculate the uptake of battery storage systems. Multiply the yearly uptake by the predicted average size of a battery storage system (10kWh), to calculate a predicted yearly uptake in MWh.
5. Calculate the yearly maximum demand reduction by taking into account the maximum discharge rate of the fleet of battery storage systems (a MW figure equivalent to 37% of the energy storage capacity) and the proportion of systems that are expected to be discharging at the time of summer maximum demand (assumed to be 60%).

Electric vehicles

The uptake of EVs in Australia is low compared to world leading countries such as Norway and the Netherlands. Without government policy support for the adoption of EVs, uptake is expected to be limited in the short-term. The availability of affordable EVs assisted by the expected reduction in battery costs will likely lift EV sales in the medium to longterm.

Powerlink has adopted the neutral uptake scenario from the Electric Vehicle Insights paper[1] prepared in September 2017 by Energeia for Australian Energy Market Operator (AEMO).

It is estimated that a 1% penetration of electric vehicles on the road would result in approximately 0.2% increase in total energy usage.

[1] Available on AEMO's website

It is expected that most owners will charge their electric vehicles during off peak periods, resulting in minimal increase in maximum demand. Therefore, Powerlink has not included a specific adjustment for electric vehicles in its maximum demand forecast.

Tariff reform and demand side management

Network tariff reforms could influence consumer behaviour, shifting energy usage away from peak times. In addition to this maximum demand reduction, it is anticipated that network tariff reforms could also influence future use of battery storage technology, encouraging consumers to draw from batteries during maximum demand or high price times. The extent to which this occurs will depend on how quickly new tariffs are offered, the tariff structure and the adoption rate.

> *'In Australia and internationally there is evidence that customers will significantly reduce their demand in response to well-designed price signals that reward off-peak use and peak demand management. Sixty percent of trials internationally have resulted in peak reductions of 10 per cent or more.'*[2]

A challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies could meet with resistance. Some of this peak reduction is already captured through the battery storage allowance described above. An additional 180MW has been assumed within this forecast and represents a further 2% reduction in the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy consumption is expected to be negligible.

Customer momentum factor

Over the last 10 years, many customers have been purchasing appliances with higher energy efficiency ratings and adopting more energy efficient behaviours in an effort to minimise financial impacts. The electricity price metric used in the regression model is forecast to decrease by 34% over the next five years and then low growth is forecast for the last five years of the forecasting horizon. The logic hardwired within the regression model suggests that customers will change their behaviour in response to falling electricity prices.

To allow for this effect, a customer momentum factor has been developed and is explicitly incorporated within the energy and non-weather dependent demand regressions. The impact of price on electricity usage is determined for the last 10 years. Rather than simply accepting the regression model's prediction for the next 10 years, a weighting of two thirds has been applied. This results in a dampening effect, limiting the 'bounce-back' in energy and demand with the forecast reduction of electricity prices.

It is expected that this factor will be reduced or removed in future years as additional information on customers' actual behaviour during falling and moderating electricity prices is captured in the data series.

Weather correction methodology

Maximum demand is strongly related to the temperature. To account for the natural variation in the weather from year to year, temperature correction is carried out to normalise raw demand observations. Three conditions are calculated:

- 10% PoE demand, corresponding to a one in 10-year season (i.e. a particularly hot summer or cold winter)
- 50% PoE demand, which indicates what the demand would have been if it was an 'average' season
- 90% PoE demand, corresponding to a nine in 10-year season (particularly mild weather).

Within each year, separate temperature corrections are calculated for extended summer and extended winter seasons. For the purposes of weather correction, summer is defined as November to March and winter is taken as May to August.

Temperature correction is applied to historical metered load supplied to connection points with Ergon and Energex. Powerlink's other direct-connect customers are largely insensitive to temperature.

[2] Towards a National Approach to Electricity Network Tariff Reform (page 6) – ENA Position Paper December 2014.

Powerlink's temperature correction process is described below:

Develop composite temperature

The temperature from multiple weather stations is combined to produce a composite temperature for all of Queensland. The weighting of each weather station is based on the proportion of Energex and Ergon-supplied load in the vicinity of that weather station.

Exclude mild days and holidays

To ensure that the fitted model accurately describes the relationship between temperature and maximum demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are excluded from the dataset.

Calculate a regression model for each season since 2000

A regression model is calculated for each summer since 2000/01 and winter since 2000, expressing the daily maximum demand as a function of: daily maximum temperature, daily minimum temperature, daily 6pm temperature, and whether the day is a weekday.

For each season, determine the 10% and 50% PoE thresholds using 23 years of weather data

The regression model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the maximum demand would have been on each day if the relationship between maximum demand and temperature described by the model had existed at the time. A Monte-Carlo approach is used to incorporate the standard error from each season's regression model. The maximum demand calculated for each of the 23 years is recorded in a list, and the 10th, 50th and 90th percentile of the list is calculated to determine the 10% PoE, 50% PoE and 90% PoE thresholds.

Final Scaling to avoid bias

To ensure that temperature correction process does not introduce any upward or downward bias, for each summer since 2000/01 and winter since 2000, the ratio of the calculated 50% PoE threshold to the actual maximum demand is calculated. The calculated PoE thresholds are divided by the average of these ratios.

Applying this methodology, the 2017/18 summer peak day was hotter than average. Therefore, the 50% PoE demand is 265MW lower than the observed maximum demand on 14 February. The 2017 winter peak day was warmer than average, resulting in an upwards adjustment of 276MW to the observed winter maximum demand.

Appendices

Appendix C – Estimated network power flows

This appendix illustrates 18 sample power flows for the Queensland region for each summer and winter over three years from winter 2018 to summer 2020/21. Each sample shows possible power flows at the time of winter or summer region 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2, with a range of import and export conditions on the Queensland/New South Wales Interconnector (QNI) transmission line.

The dispatch assumed is broadly based on historical observed dispatch of generators.

Sample conditions[1] include:

Figure C.3	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2019 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2019 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2019 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2020 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2020 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2020 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2019/20 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2020/21 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2020/21 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2021/21 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at the Gladstone South end of Callide A to Gladstone South 132kV double circuit. These open points can be closed depending on system conditions.

Table C.1 provides a summary of the grid section flows for these sample power flows and the limiting conditions capable of setting the maximum transfer.

Table C.2 lists the 275kV transformer nameplate capacity and the maximum loading of the sample power flows.

Figures C.1 and C.2 provide the generation, load and grid section legends for the subsequent figures C.3 to C.20. The reported generation and load is the transmission sent out and transmission delivered defined in Figure 2.4.

[1] The transmission network diagrams shown in this appendix are high level representations only, used to indicate zones and grid sections.

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
FNQ Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)	166/166/166	124/124/124	127/127/127	243/243/243	246/246/246	254/254/254	V
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)	695/695/695	655/654/654	664/665/665	931/931/931	933/933/933	952/952/952	Th V
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)	505/429/390	519/446/397	415/395/399	379/380/382	389/390/393	387/388/391	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) (6) Calliope River into Gin Gin 275kV (2 circuits) (6) Calvale into Halys 275kV (2 circuits)	1,539/1,845/2,032	1,537/1,843/2,067	1,961/2,060/2,059	1,753/1,753/1,753	1,747/1,747/1,747	1,754/1,754/1,754	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	564/564/564	586/586/586	589/589/589	527/527/527	540/540/540	571/571/571	V
SWQ Western Downs to Halys 275kV (2 circuits) (7) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,051/760/651	1,021/725/579	1,009/915/987	1,718/1,717/1,747	1,706/1,707/1,746	1,775/1,778/1,817	(5)

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions *(continued)*

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
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)	3,034/2,876/2,843	3,091/2,933/2,880	2,919/2,865/2,927	3,749/3,747/3,777	3,805/3,803/3,833	3,858/3,858/3,887	V
Gold Coast Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	697/697/760	703/703/766	710/710/773	844/844/875	852/852/883	855/855/886	V

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) Grid power flows are derived from the assumed generation dispatch cases shown in figures C.3 to C.20. The flows estimated for system normal operation are based on the existing network configurations and committed projects. Power flow across each grid section can be higher at times of local zone peak.

(3) All grid section power flows shown are within network capability.

(4) Tr = Transient stability limit, V = Voltage stability limit and Th = Thermal plant rating.

(5) As stated in Section 6.6.6, SWQ grid section is not expected to impose limitations to power transfer under intact system conditions with the existing levels of generating capacity.

(6) Applies by summer 20/21 after the Gin Gin Substation rebuild. CQSQ cutset redefined following Gin Gin Substation rebuild in summer 2020/21. Wurdong into GinGin 275kV becomes Wurdong to Teebar Creek 275kV. Calliope River into Gin Gin 275kV becomes Calliope River to Gin Gin/Woolooga 275kV.

(7) Coopers Gap connects to a Western Downs to Halys circuit from winter 2019.

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers

275kV substation (1)(2)(3)(4)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
(Number of transformers x MVA nameplate rating)		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	15	27	17	25	26	29	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	119	147	133	229	229	234	Barron Gorge generation	Kareeya and Ross zone generation
Ross 275/132kV (3x250MVA)	R	236	160	160	238	243	252	Ross zone generation	North zone generation
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	270	266	269	315	316	316	Mackay GT generation	North zone generation
Strathmore 275/132kV (1x375MVA)	N	123	123	122	155	150	153	Invicta and North zone generation	Ross zone generation
Bouldercombe 275/132kV (1x200MVA and 1x375MVA)	CW	144	146	147	168	169	168		
Calvale 275/132kV (1x250MVA)	CW	131	138	120	167	146	148	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	188	184	198	195	212	217	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132 kV (2x375MVA)	G	49	47	43	50	49	47	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	151	163	165	151	161	150		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	89	87	85	75	78	83	Wide Bay zone embedded generation	CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	231	235	236	232	233	236		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	165	162	147	176	150	141	Surat zone generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	310	319	328	292	296	296	Oakey generation	

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

275kV substation (1)(2)(3)(4)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
(Number of transformers x MVA nameplate rating)		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	42	45	41	20	33	33	Surat zone generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	35	36	36	41	42	41		
Abermain 275/110kV (1x375MVA)	M	153	155	150	188	190	192	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250MVA and 2x375MVA)	M	442	434	450	538	541	553	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250MVA and 1x240MVA)	M	176	178	177	219	220	225		
Goodna 275/110kV (1x375MVA)	M	145	147	151	186	187	189	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	379	382	385	464	469	473	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	354	357	361	431	437	442		
Palmwoods 275/132kV (2x375MVA)	M	308	321	311	354	358	370		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	336	340	345	418	424	415	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Blackstone and Swanbank E generation
South Pine East 275/110kV (3x375 MVA)	M	573	590	580	679	689	690		
South Pine West 275/110kV (1x375MVA and 1x250MVA)	M	255	262	260	305	310	307		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	466	474	479	547	554	559	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector

275kV substation (1)(2)(3)(4)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
(Number of transformers x MVA nameplate rating)		Winter 2018	Winter 2019	Winter 2020	Summer 2018/19	Summer 2019/20	Summer 2020/21	Significant dependence on	Minor dependence on
Mudgeeraba 275/110kV (3x250MVA)	GC	325	329	331	374	378	381	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea

Notes:

(1) Not included are 275/132kV tie transformers within the Calliope River Substation. Loading on these transformers varies considerably with local generation.

(2) Not included are 330/275kV transformers located at Braemar and Middle Ridge substations. Loading on these transformers is dependent on QNI transfer and south west Queensland generation.

(3) To protect the confidentiality of specific customer loads, transformers supplying a single customer are not included.

(4) Nameplate based on present ratings. Cyclic overload capacities above nameplate ratings are assigned to transformers based on ambient temperature, load cycle patterns and transformer design.

(5) Zone abbreviations are defined in Appendix A.

(6) Substation loadings are derived from the assumed generation dispatch cases shown within figures C.3 to C.20. The loadings are estimated for system normal operation and are based on the existing network configuration and committed projects. MVA loadings for transformers depend on power factor and may be different under other generation patterns, outage conditions, local or zone maximum demand times or different availability of local and dowstream capacitor banks.

(7) Substation loadings are the maximum of each of the northerly/zero/southerly QNI scenarios for each year/season shown within the assumed generation dispatch cases in figures C.3 to C.20.

(8) Under outage conditions the MVA transformer loadings at substations may be lower due to the interconnected nature of the subtransmission network or operational switching strategies.

Figure C.1 Generation and load legend for figures C.3 to C.20

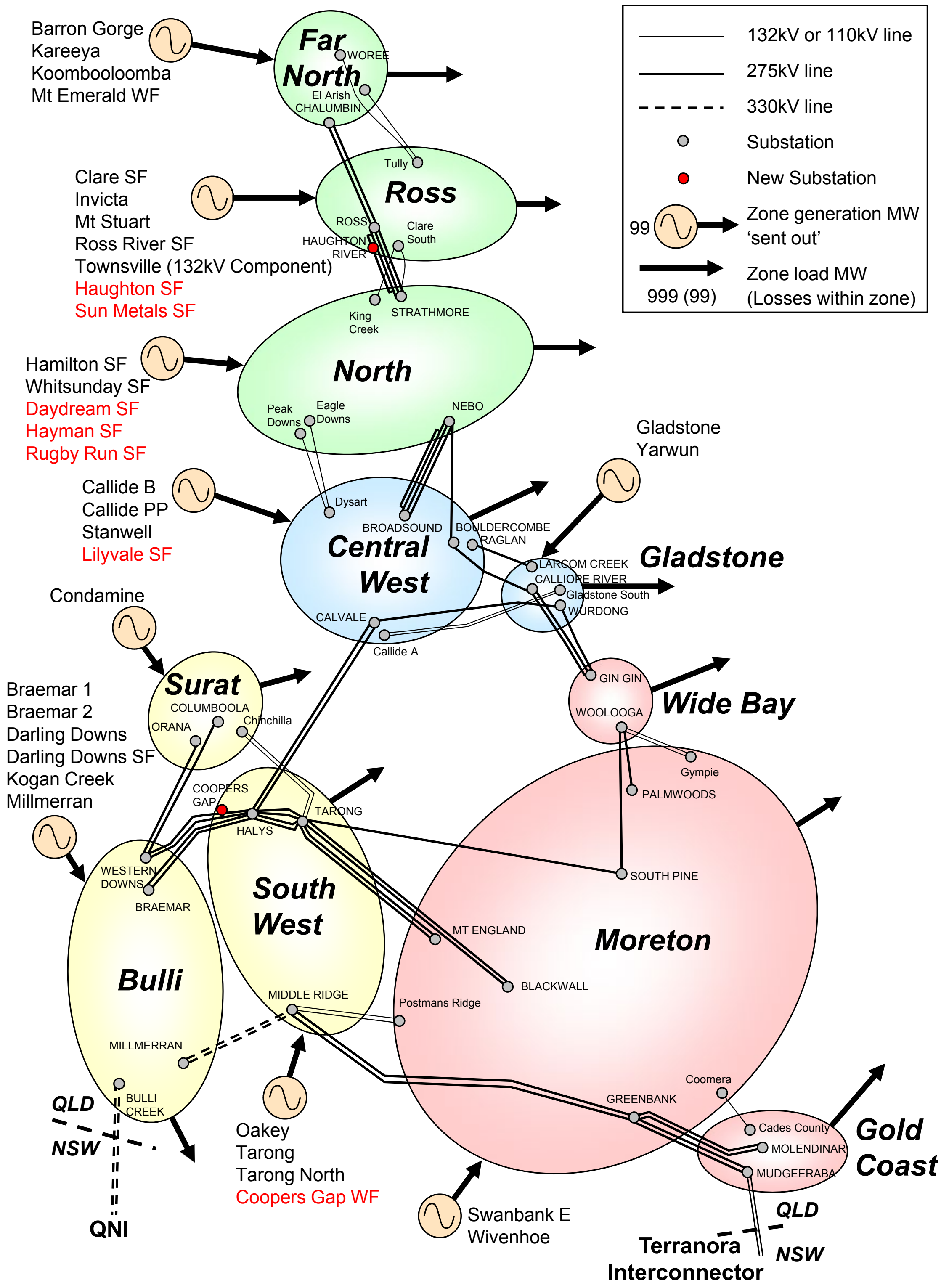


Figure C.2 Generation and load legend for figures C.3 to C.20

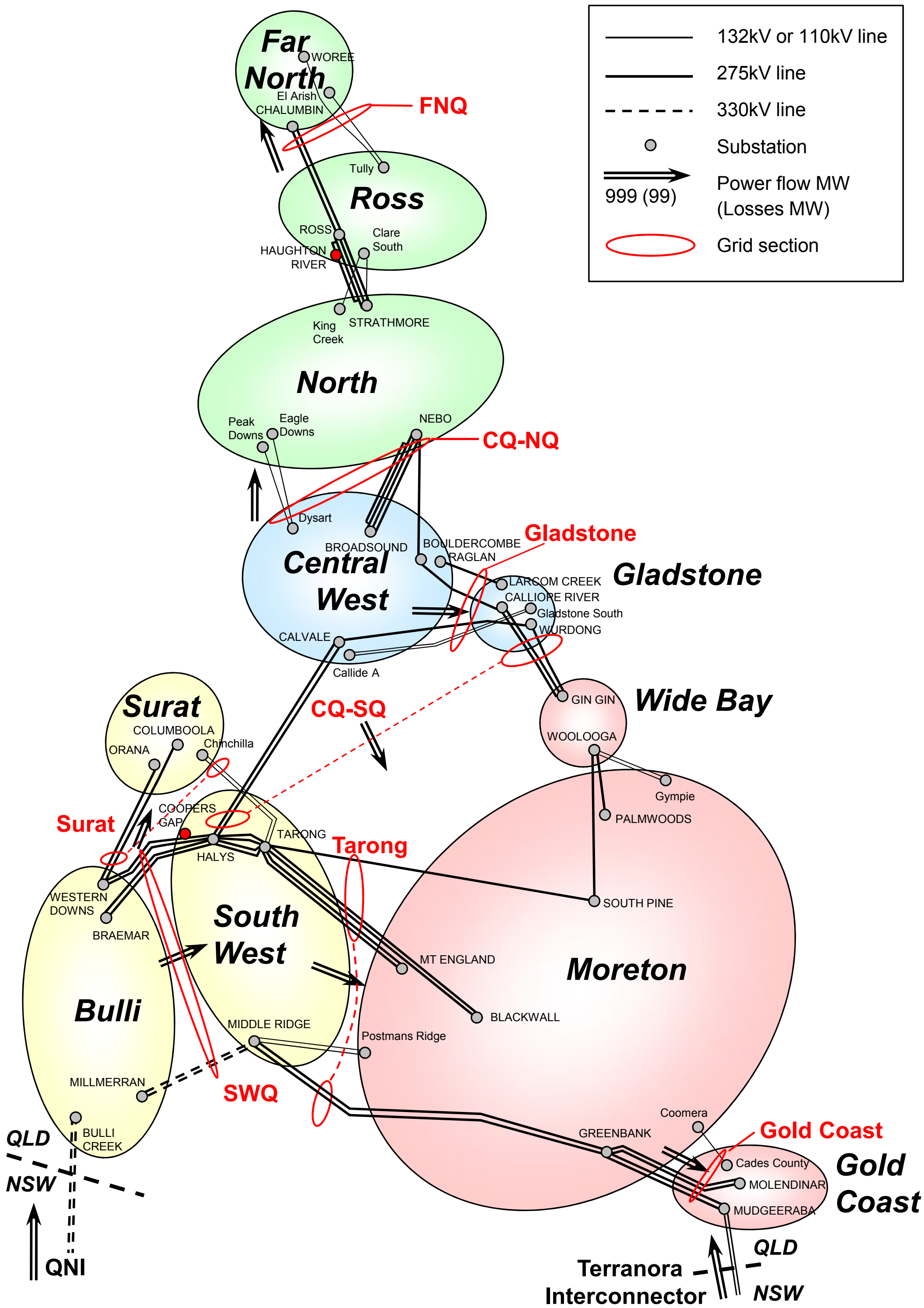
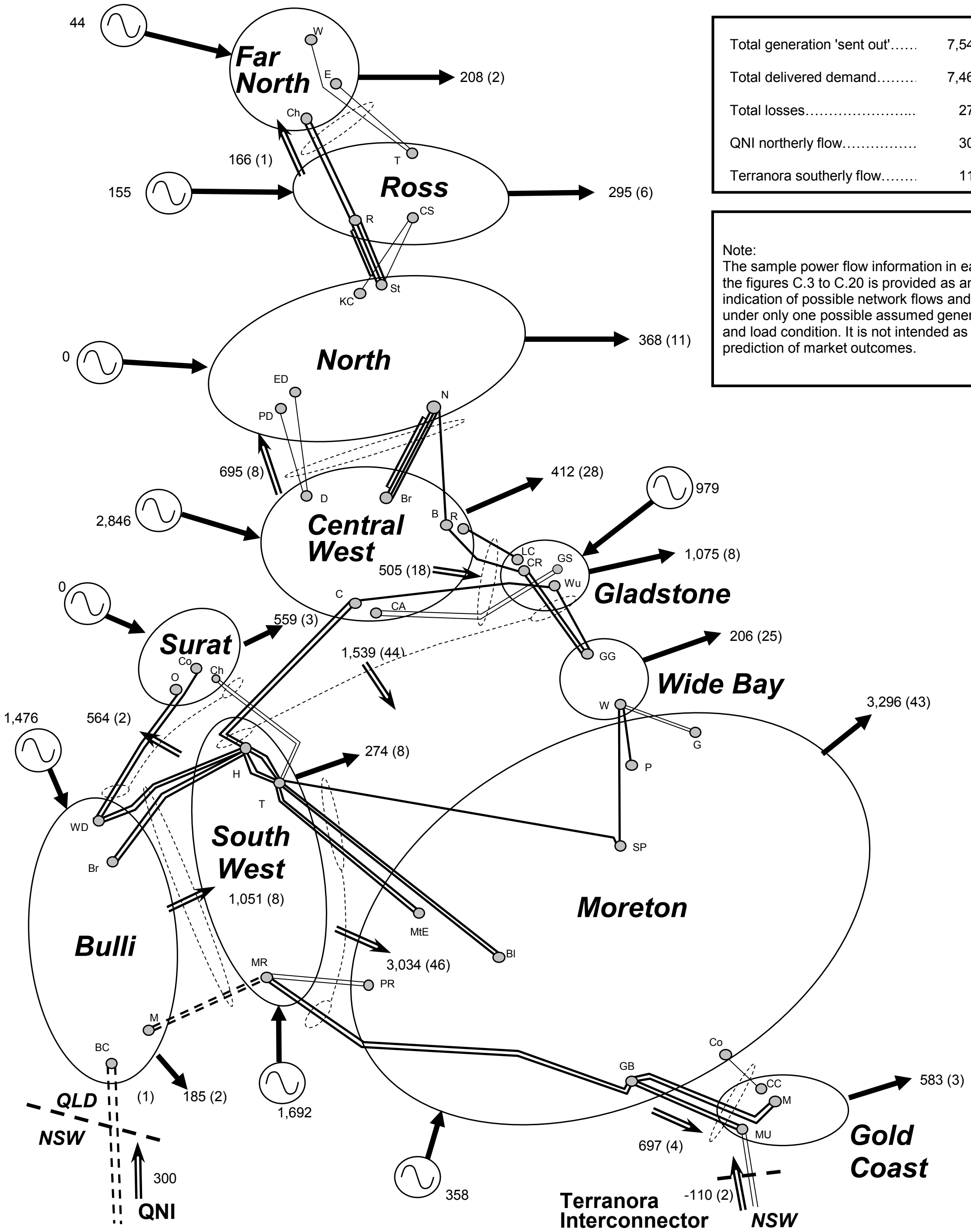


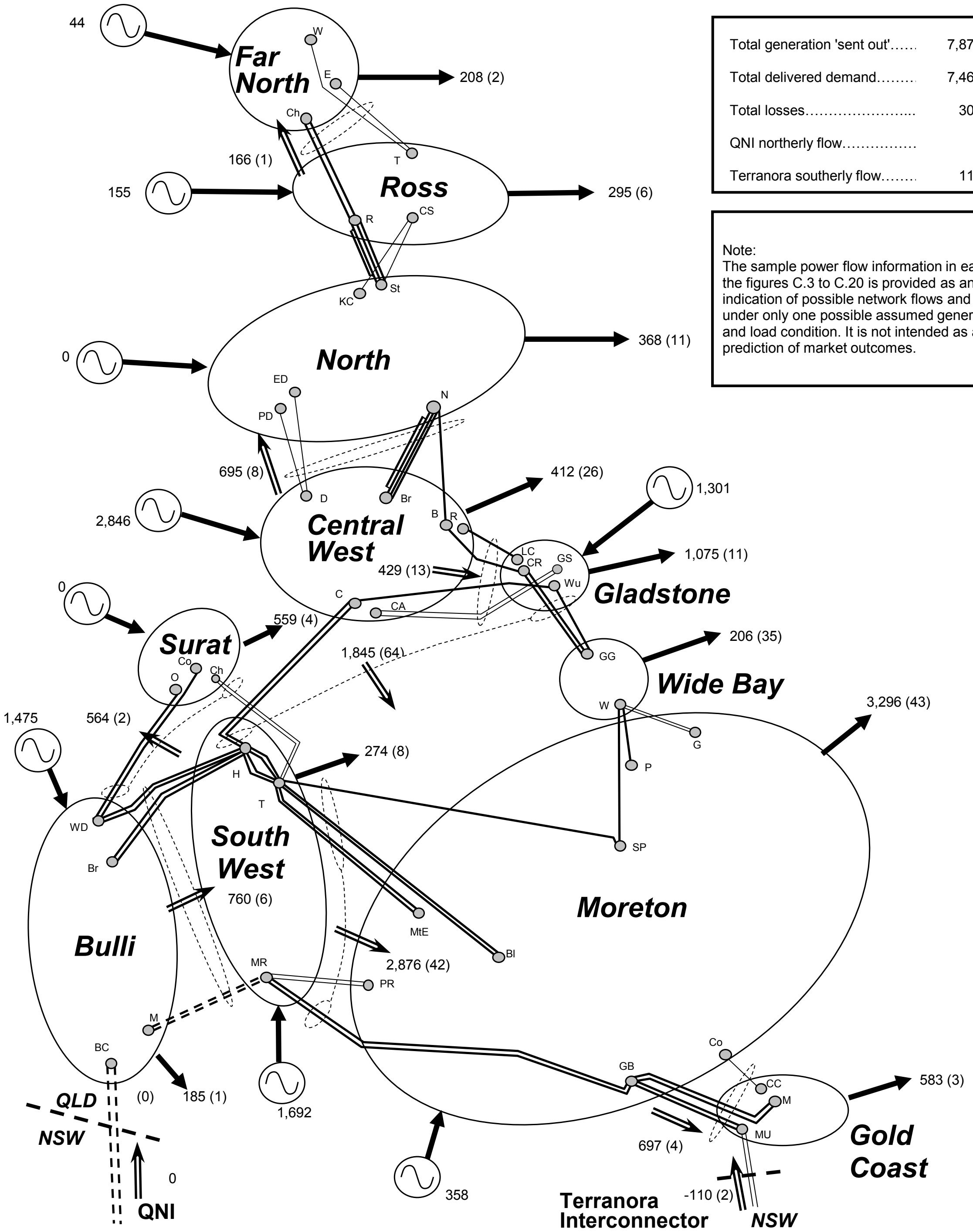
Figure C.3 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'……	7,549 MW
Total delivered demand………	7,461 MW
Total losses…………………..	278 MW
QNI northerly flow…………….	300 MW
Terranora southerly flow……..	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.4 Winter 2018 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'......	7,871 MW
Total delivered demand........	7,461 MW
Total losses........................	300 MW
QNI northerly flow................	0 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.5 Winter 2018 Queensland maximum demand 700MW southerly QNI flow

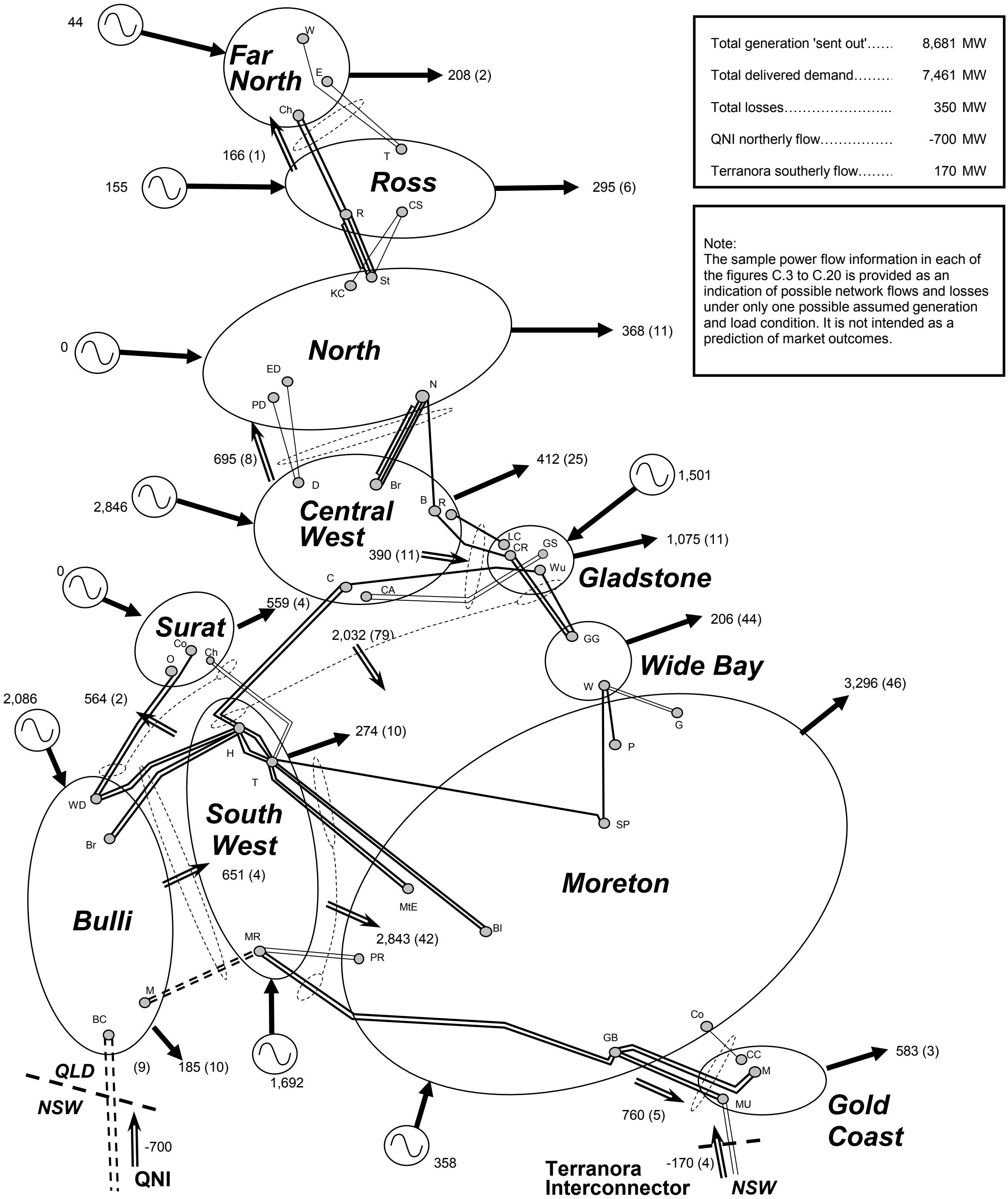
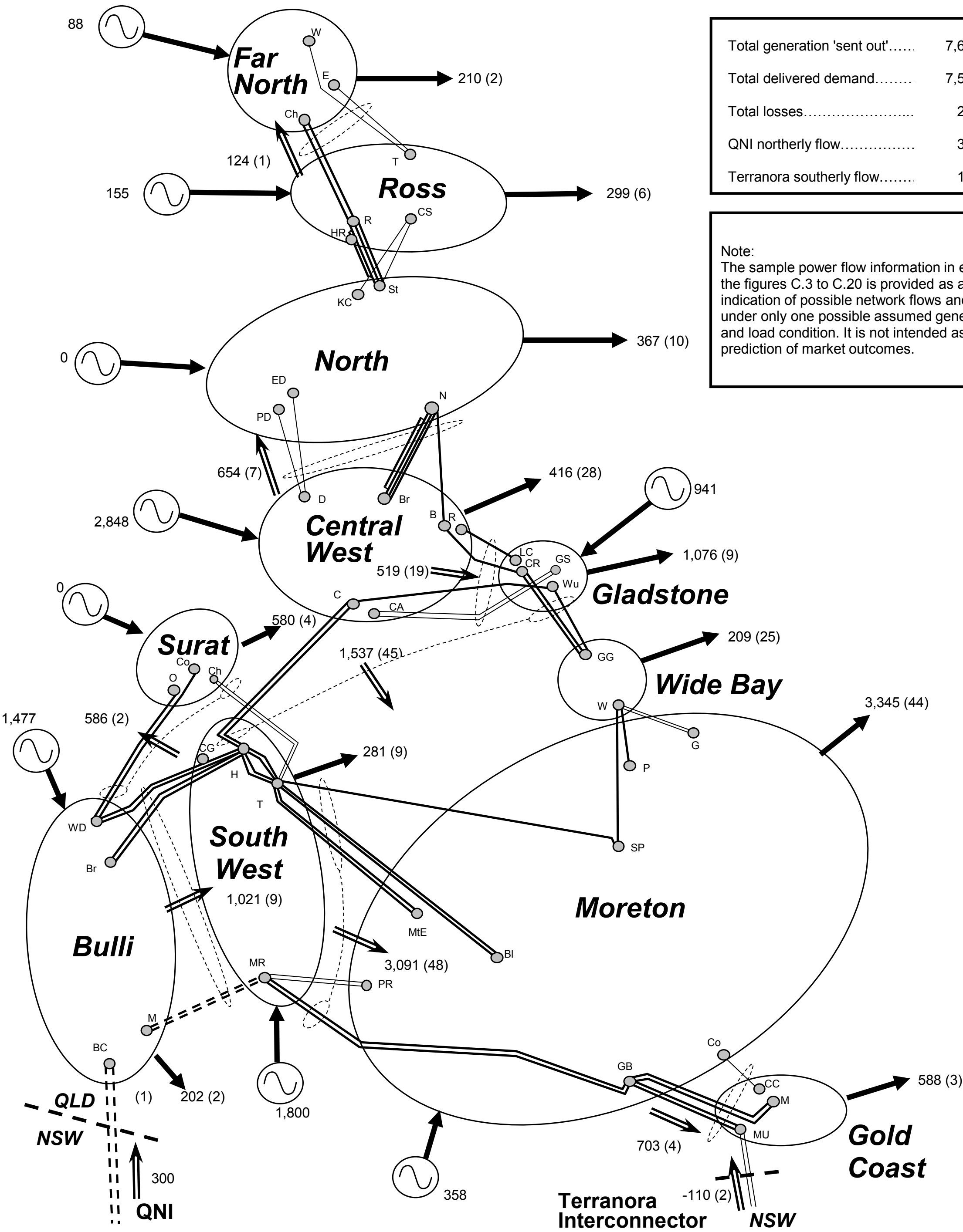


Figure C.6 Winter 2019 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'……	7,667 MW
Total delivered demand……..	7,572 MW
Total losses…………………..	284 MW
QNI northerly flow…………….	300 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.7 Winter 2019 Queensland maximum demand 0MW QNI flow

Total generation 'sent out'……	7,985 MW
Total delivered demand………	7,572 MW
Total losses…………………..	303 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

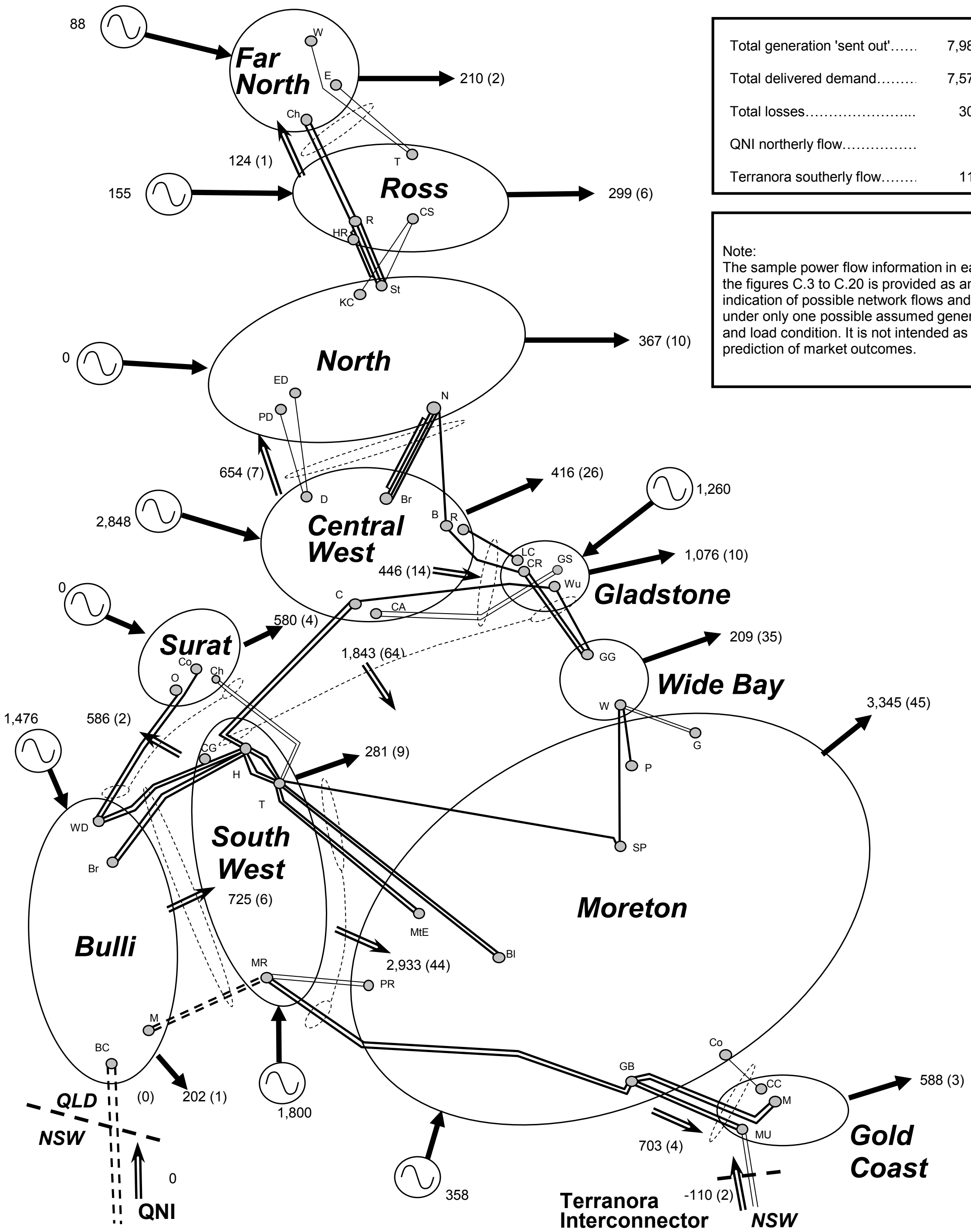
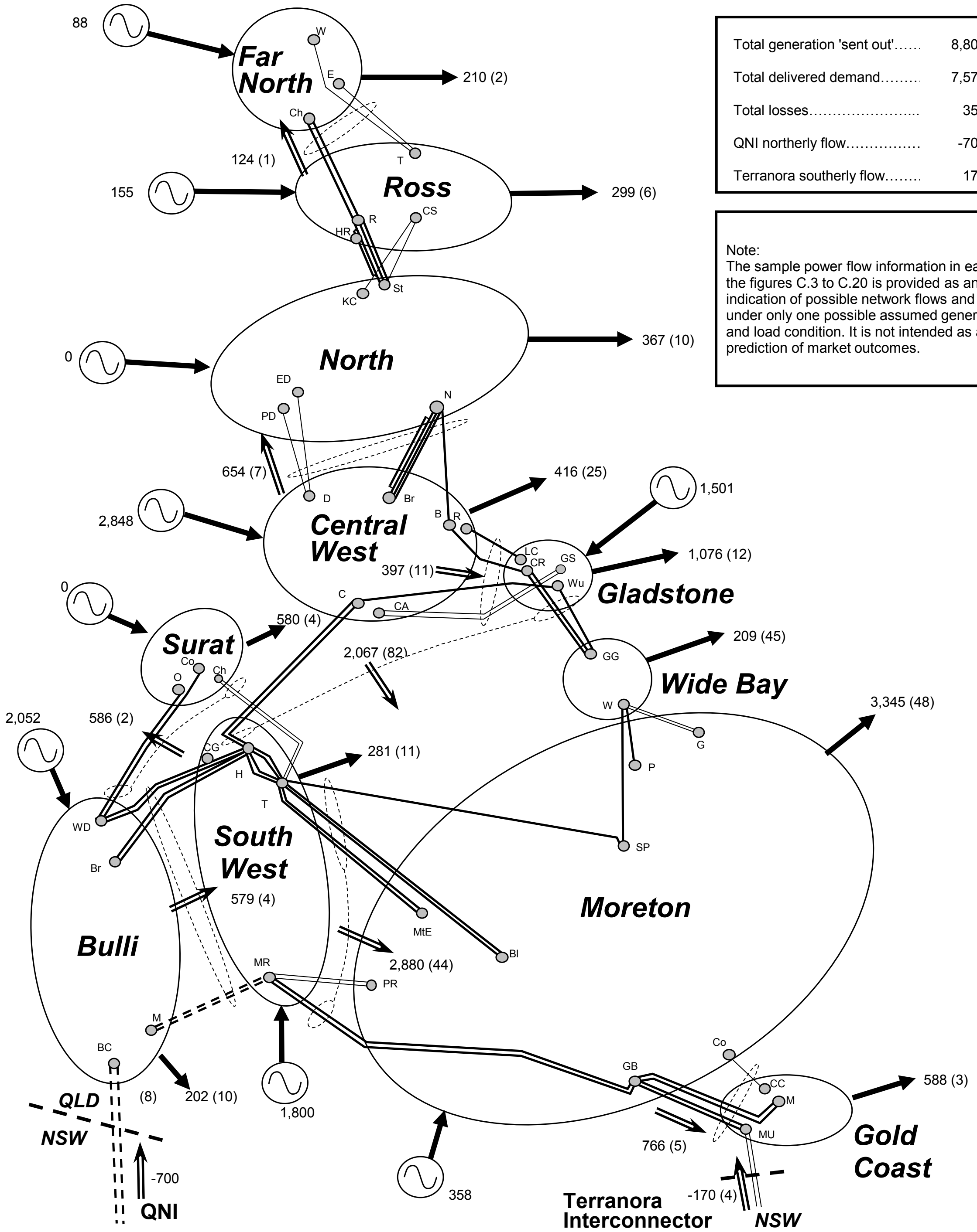


Figure C.8 Winter 2019 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,801 MW
Total delivered demand……..	7,572 MW
Total losses…………………...	358 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow…….	170 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.9 Winter 2020 Queensland maximum demand 300MW northerly QNI flow

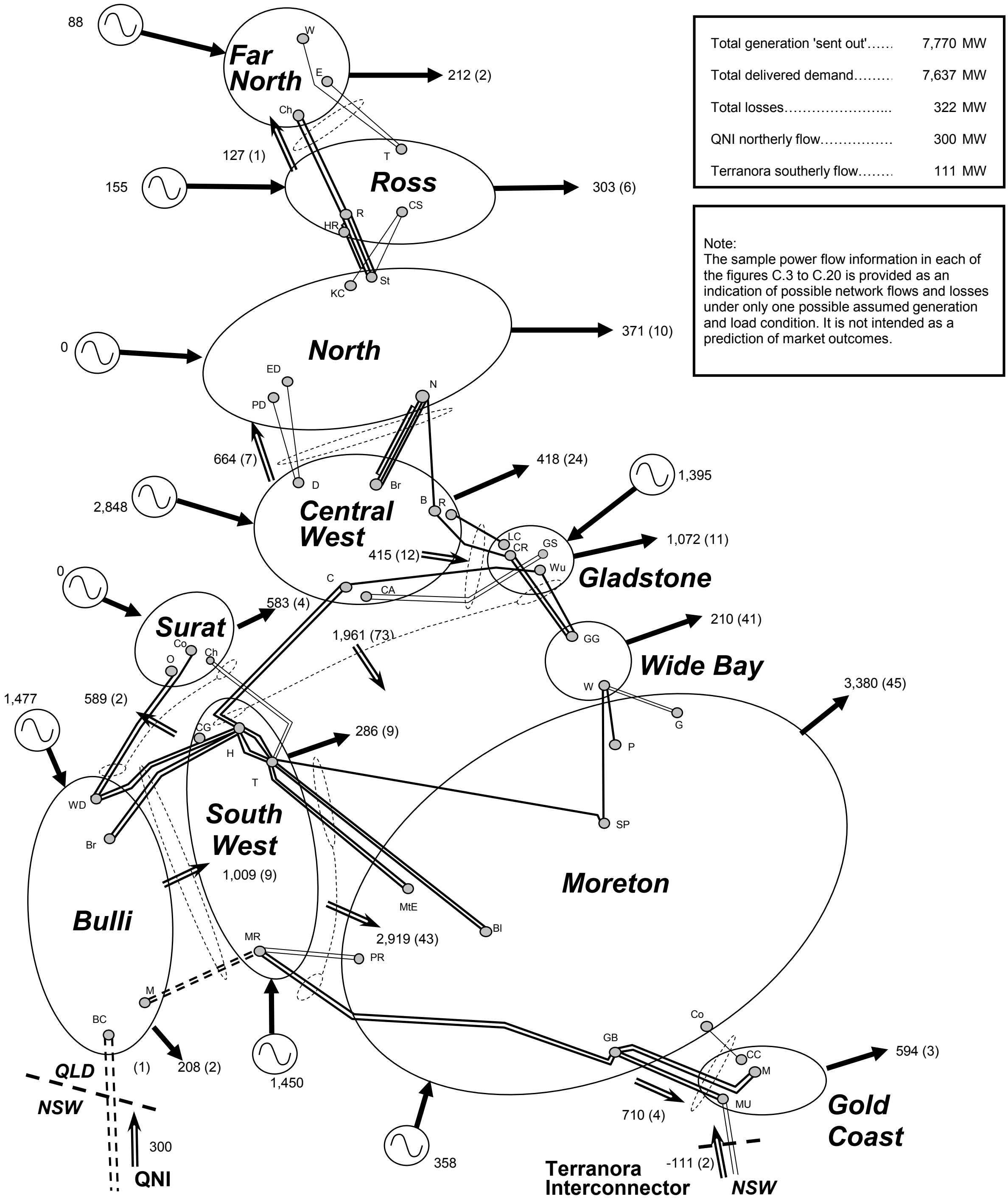
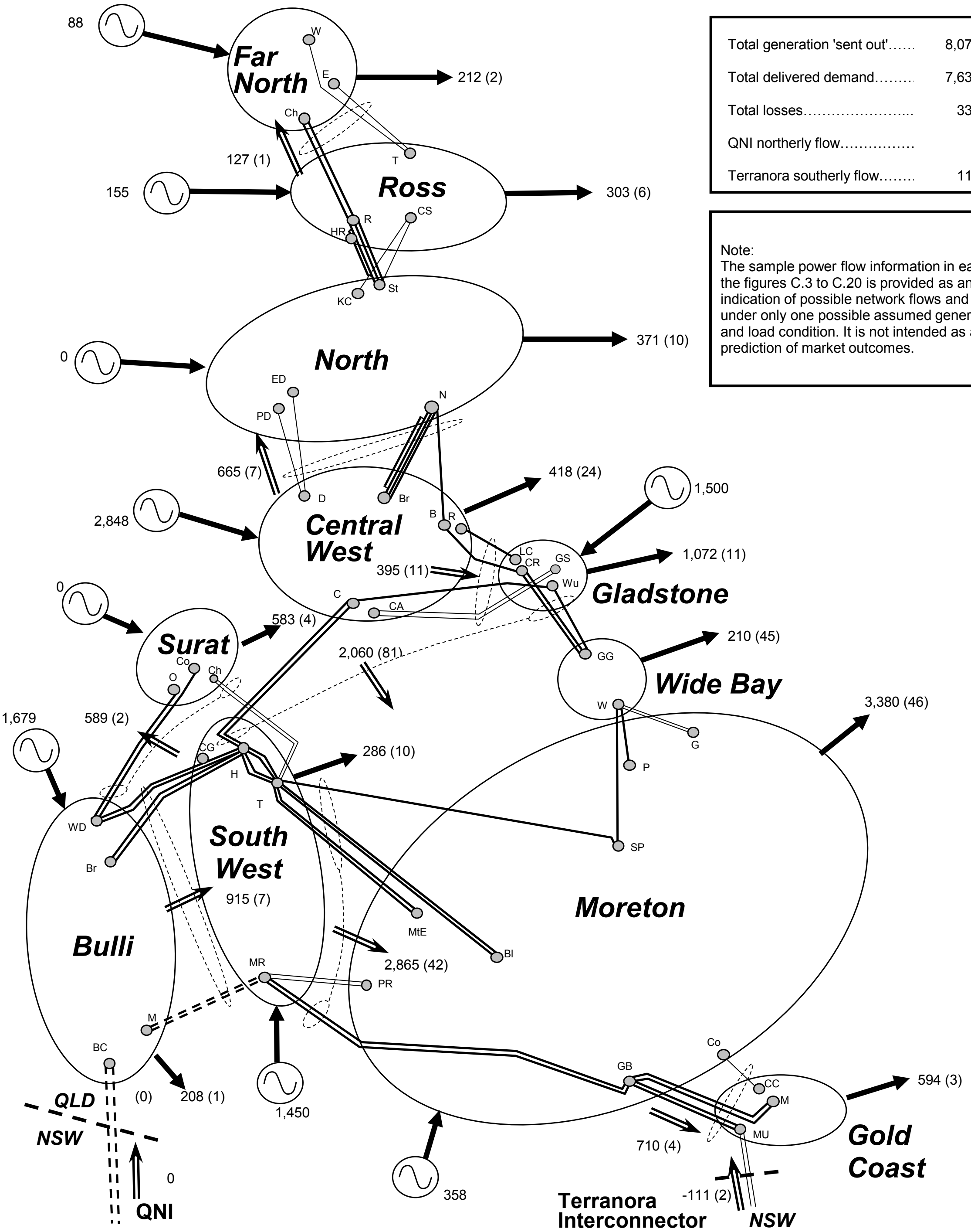


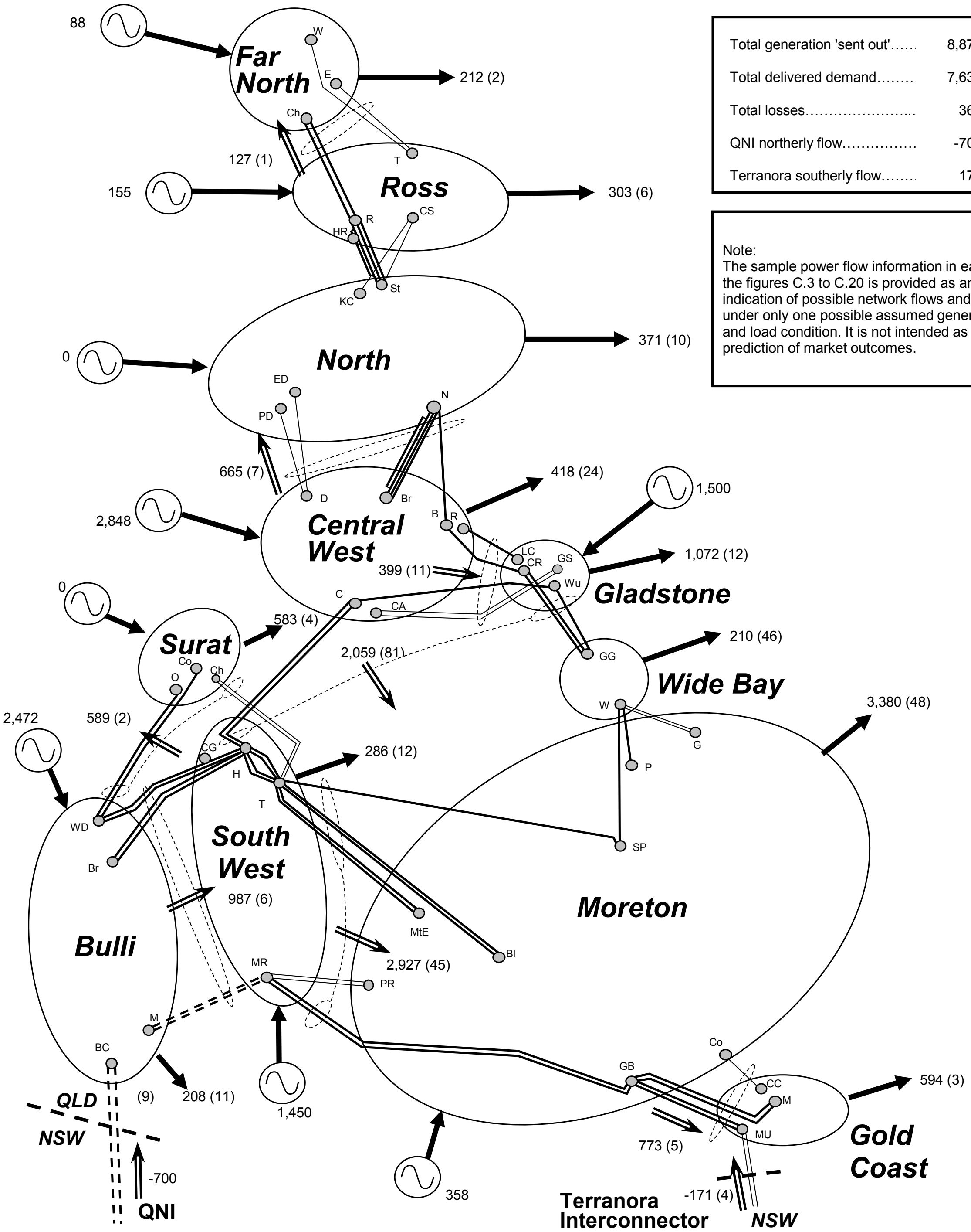
Figure C.10 Winter 2020 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'......	8,078 MW
Total delivered demand........	7,637 MW
Total losses........................	330 MW
QNI northerly flow................	0 MW
Terranora southerly flow........	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

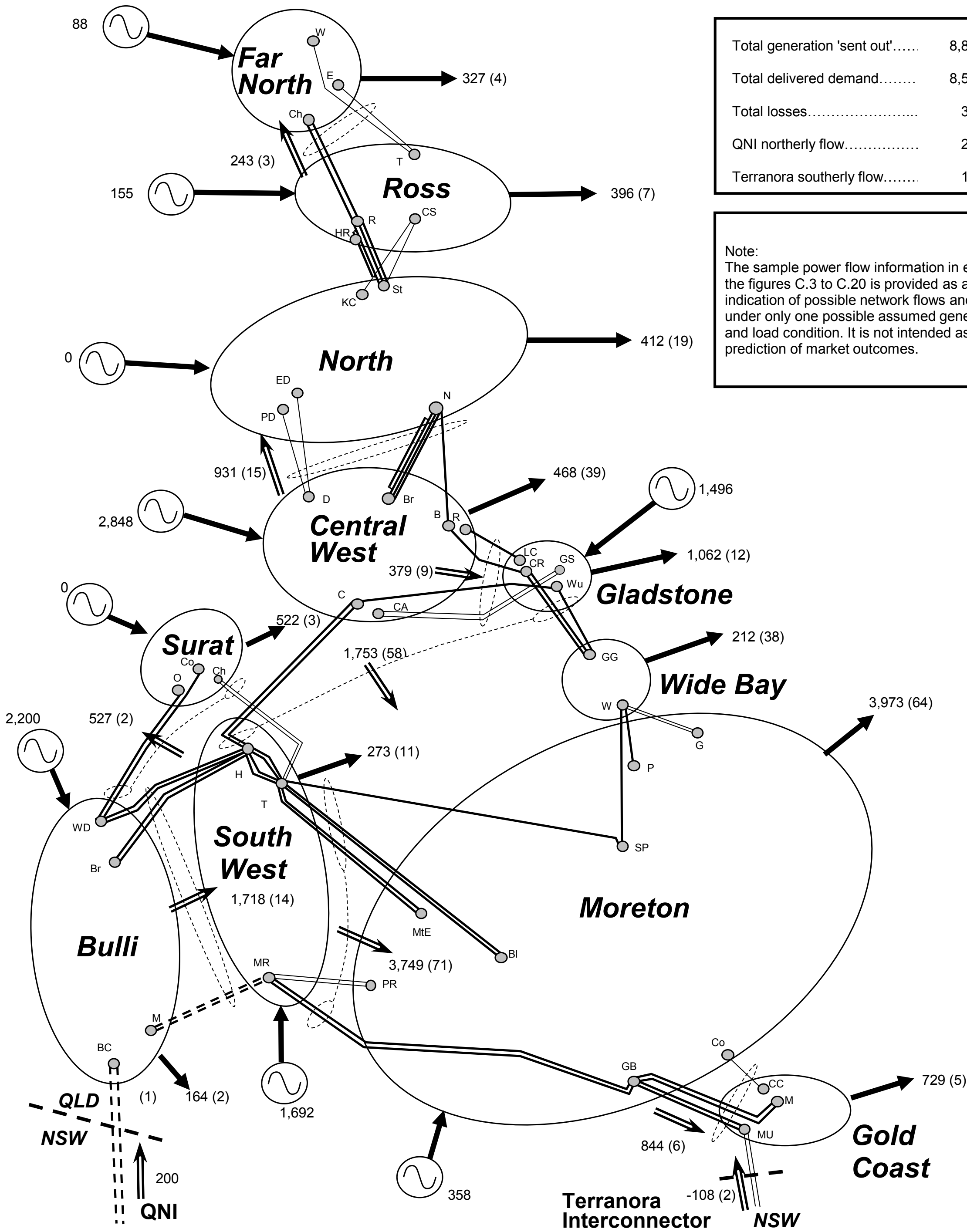
Figure C.11 Winter 2020 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'……	8,872 MW
Total delivered demand………	7,637 MW
Total losses…………………...	364 MW
QNI northerly flow…………….	-700 MW
Terranora southerly flow……..	171 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.12 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'......	8,835 MW
Total delivered demand........	8,538 MW
Total losses........................	389 MW
QNI northerly flow................	200 MW
Terranora southerly flow........	108 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.13 Summer 2018/19 Queensland maximum demand 0MW QNI flow

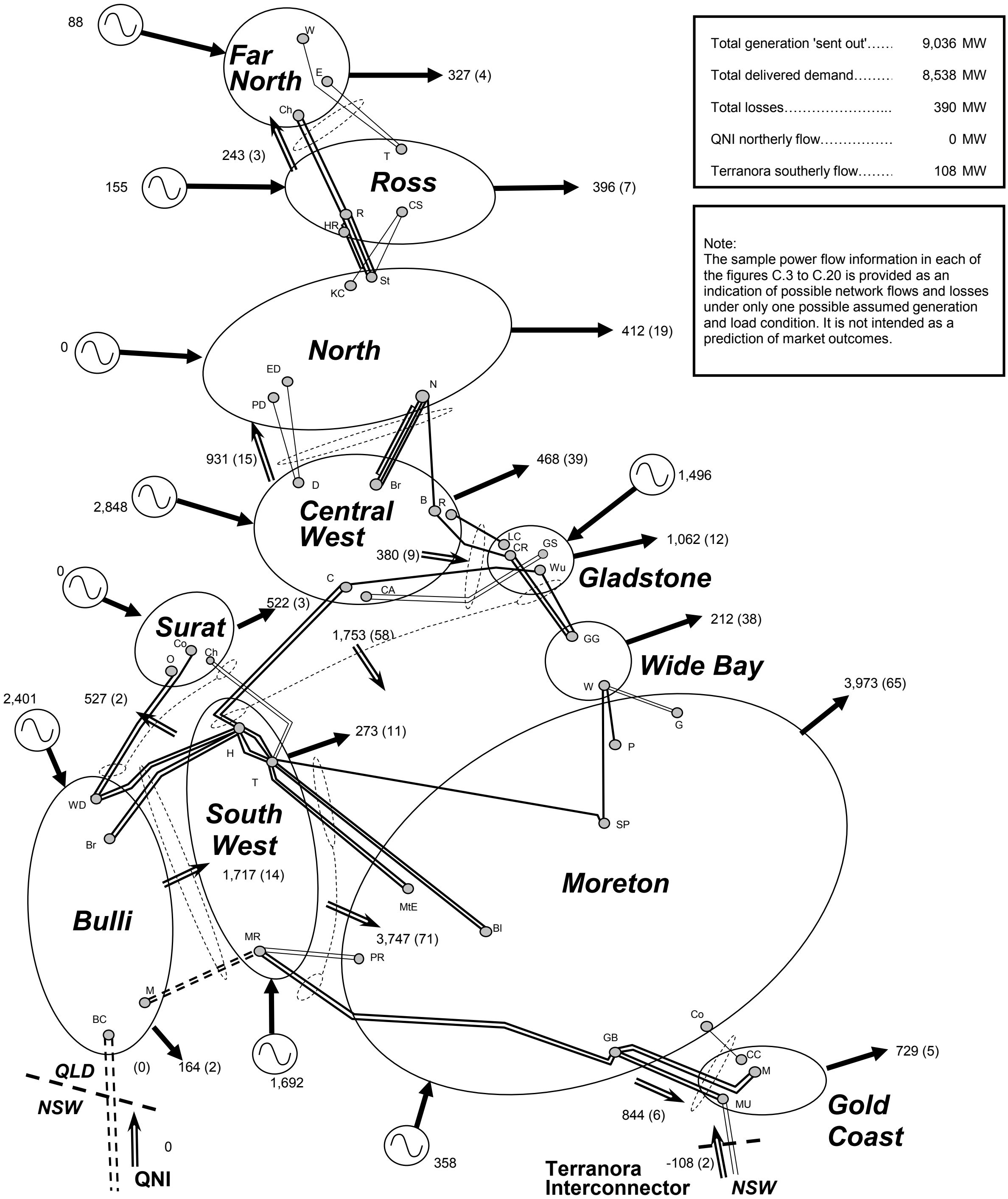


Figure C.14 Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow

Total generation 'sent out'......	9,480 MW
Total delivered demand........	8,538 MW
Total losses........................	404 MW
QNI northerly flow................	-400 MW
Terranora southerly flow.......	138 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

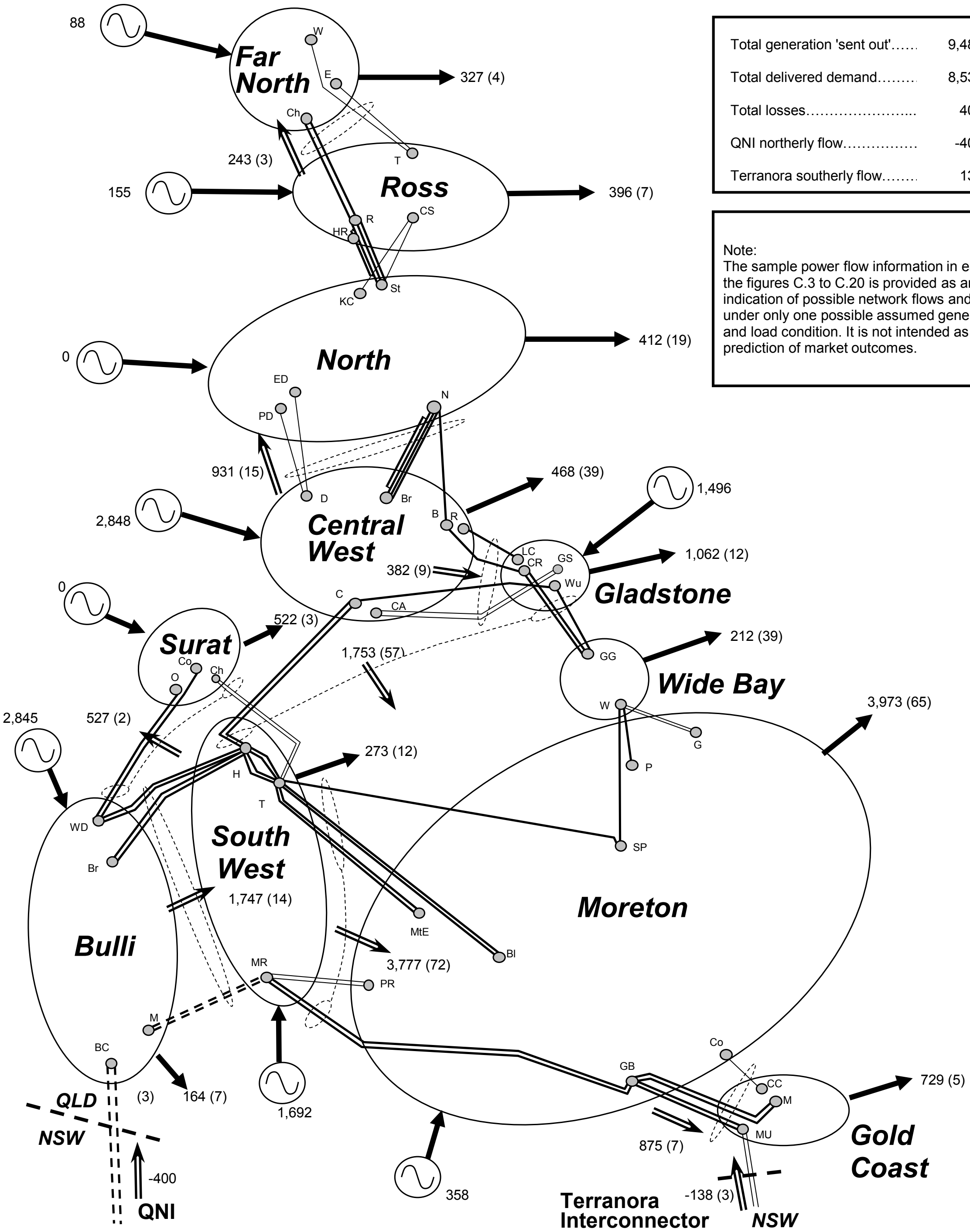
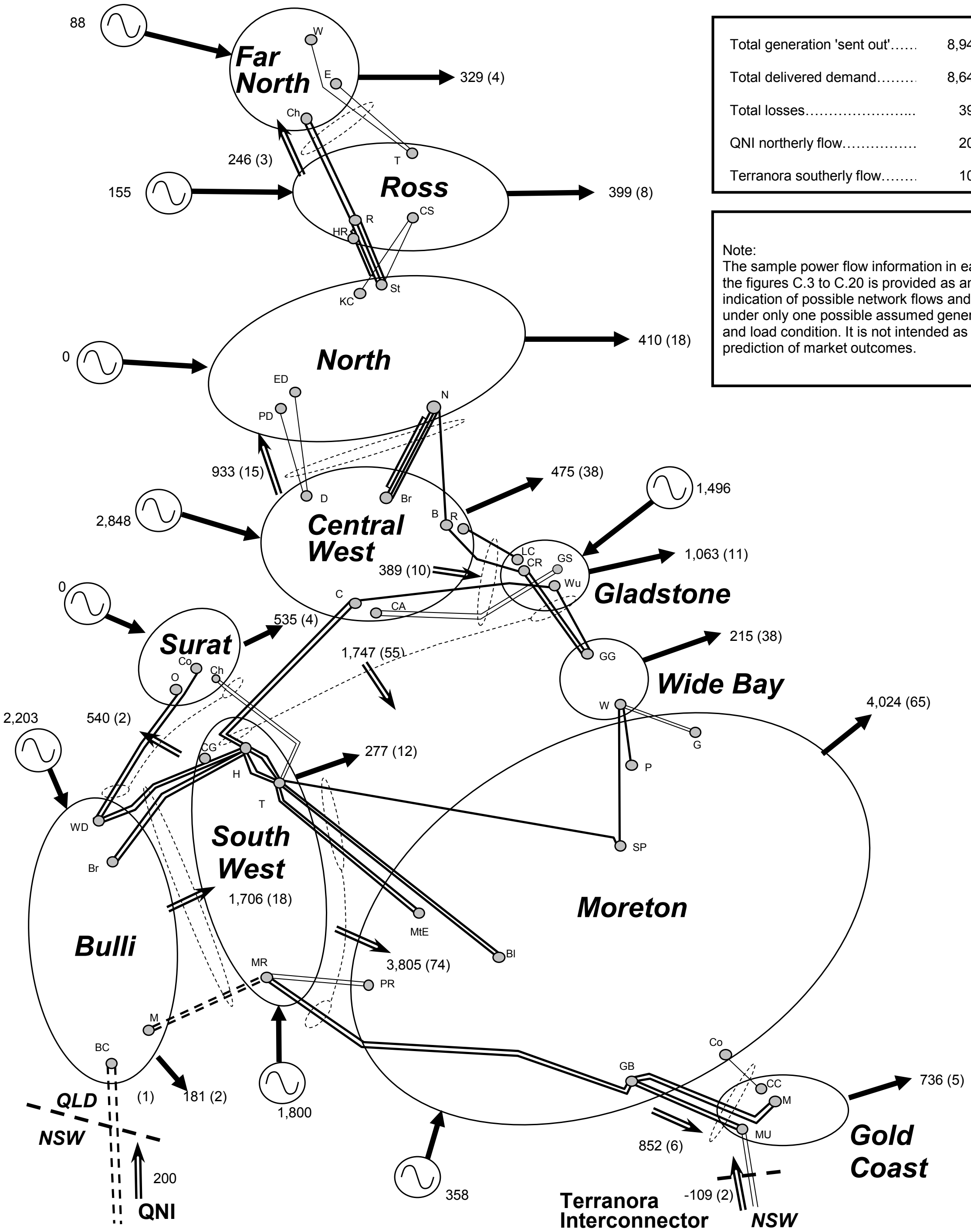


Figure C.15 Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'……	8,947 MW
Total delivered demand………	8,642 MW
Total losses…………………...	396 MW
QNI northerly flow…………….	200 MW
Terranora southerly flow……..	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.16 Summer 2019/20 Queensland maximum demand 0MW QNI flow

Total generation 'sent out'……	9,148 MW
Total delivered demand……..	8,642 MW
Total losses…………………..	397 MW
QNI northerly flow…………….	0 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

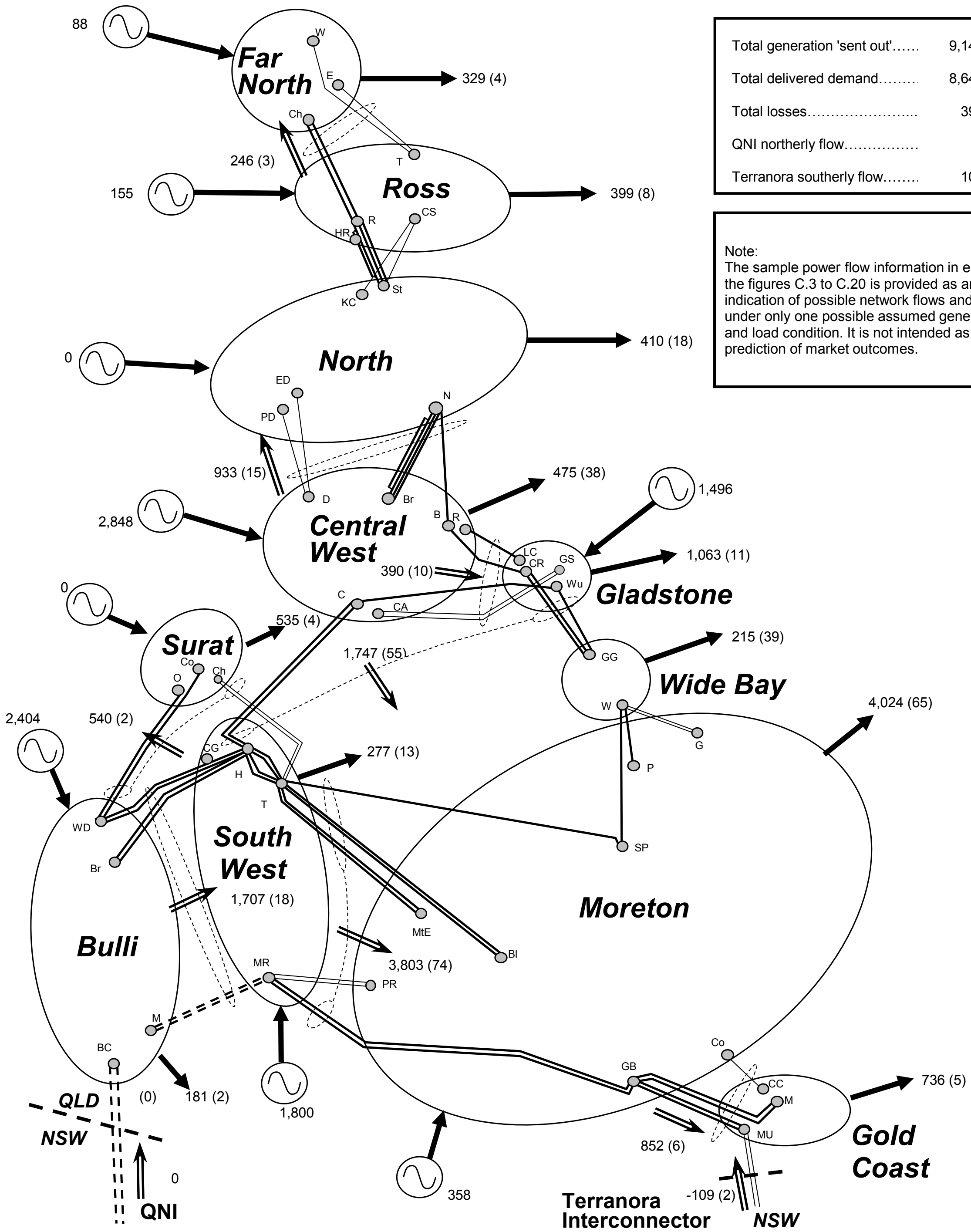


Figure C.17 Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow

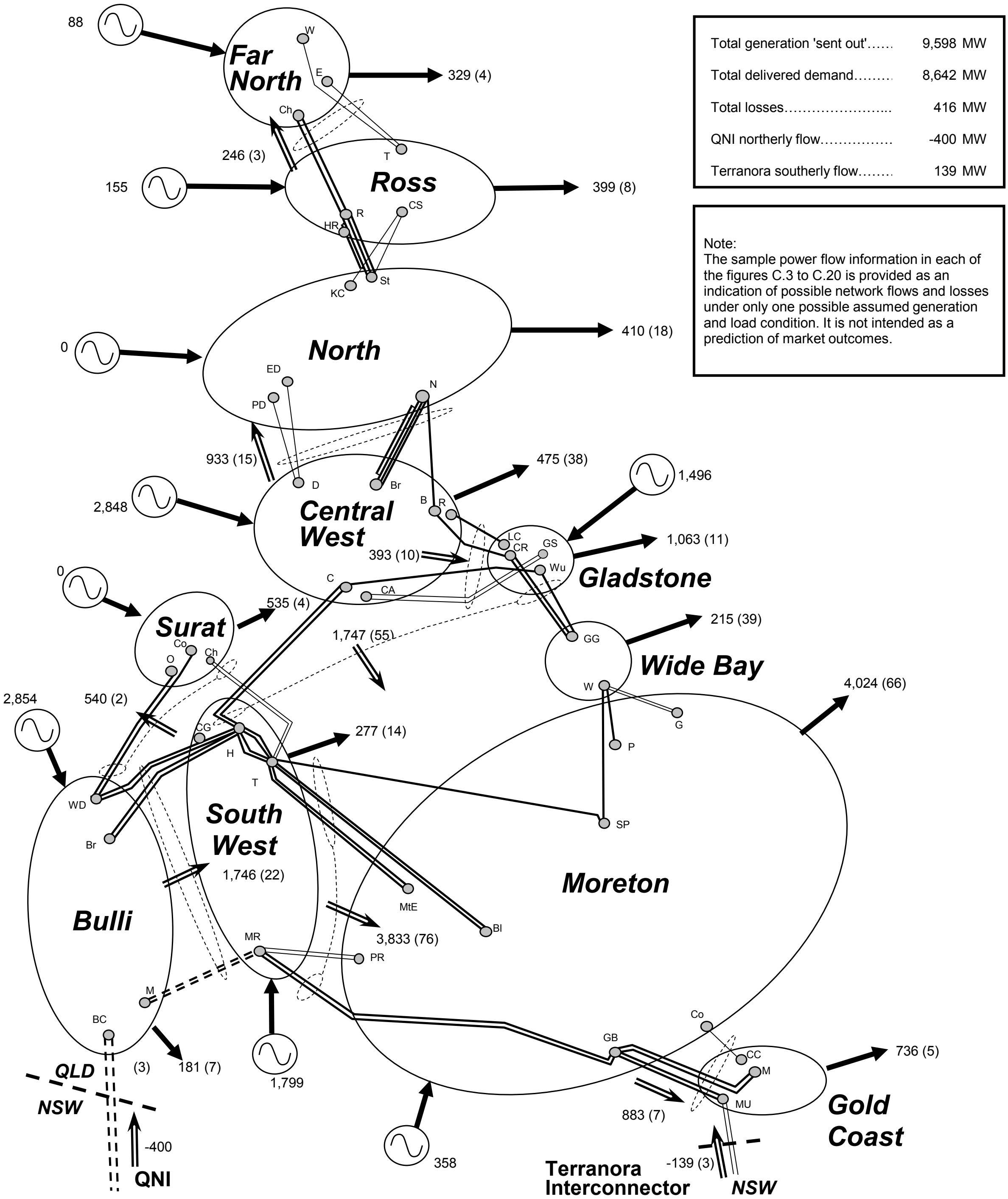


Figure C.18 Summer 2020/21 Queensland maximum demand 200MW northerly QNI flow

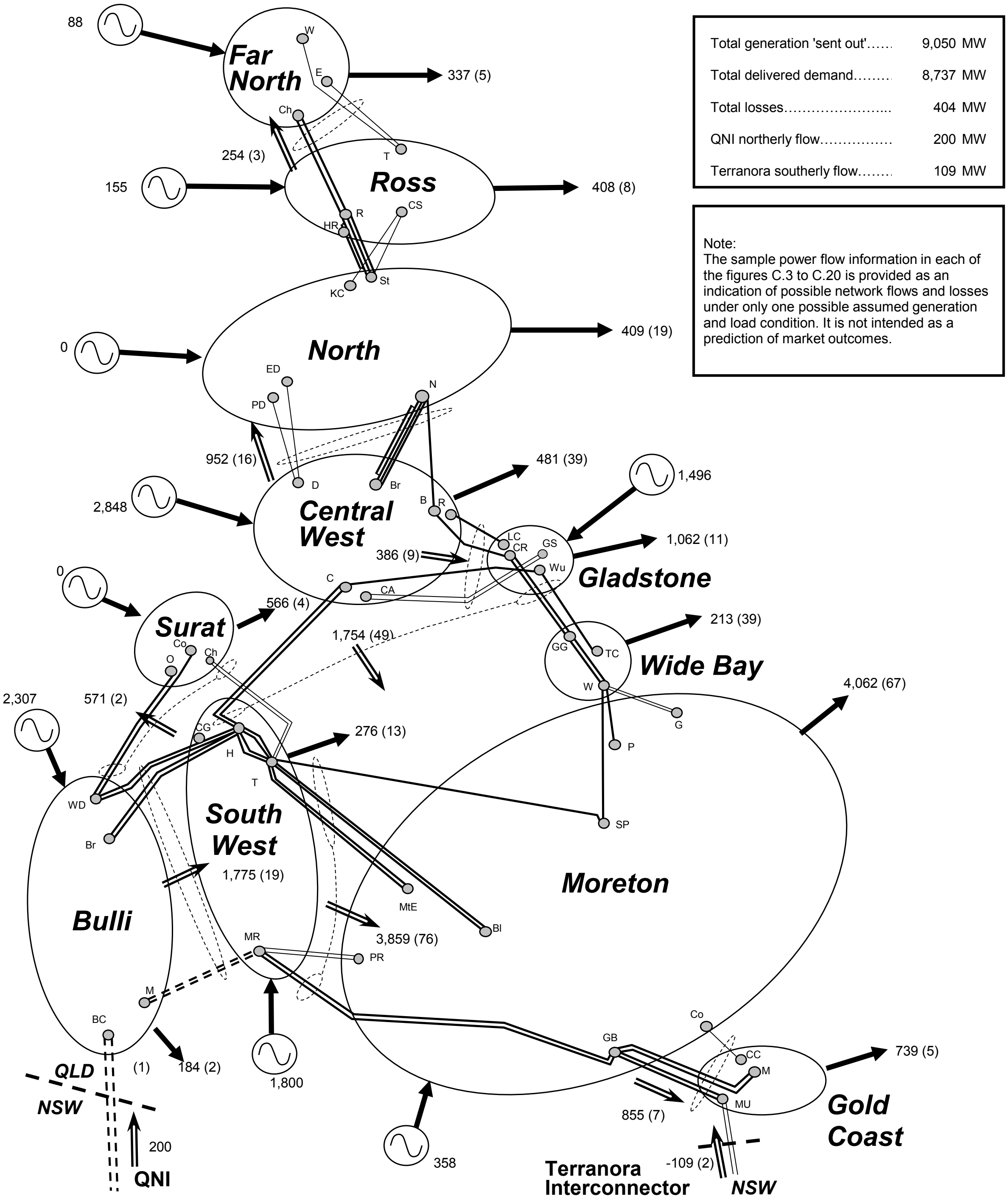
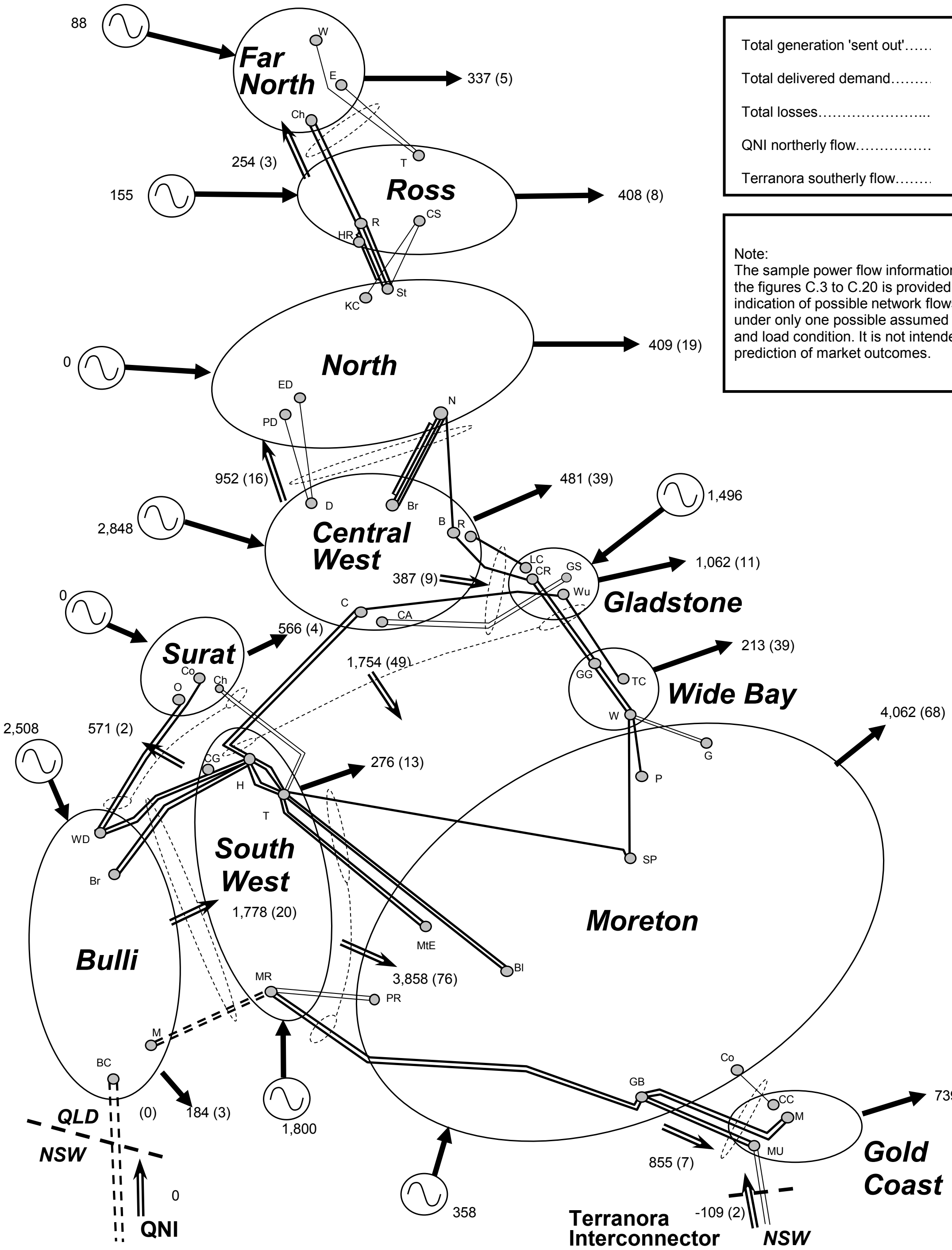


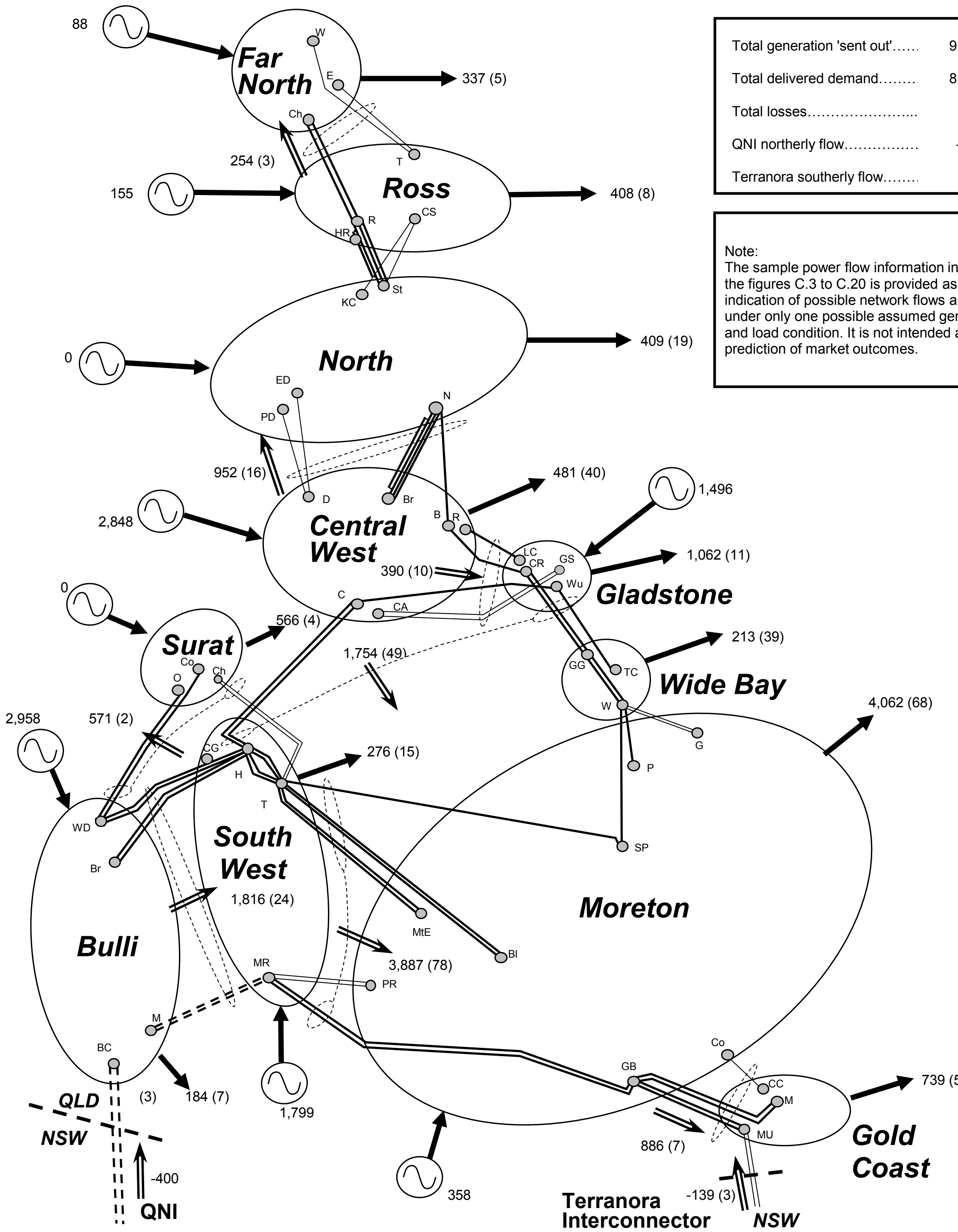
Figure C.19 Summer 2020/21 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'……	9,252 MW
Total delivered demand………	8,737 MW
Total losses……………………	406 MW
QNI northerly flow……………	0 MW
Terranora southerly flow……..	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.20 Summer 2021/21 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'……	9,702 MW
Total delivered demand……..	8,737 MW
Total losses…………………...	426 MW
QNI northerly flow…………….	-400 MW
Terranora southerly flow…….	139 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

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
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
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 + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + Sun Metals Solar Farm + Kidston + Invicta + Clare Solar Farm + Mackay) generation

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

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

Measured variable	Coefficient	
	Equation 1	Equation 2
	Feeder contingency	Townsville contingency (1)
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	-1.000
Total MW generation at Mt Stuart	-0.092	-0.136
Number of Mt Stuart units on line [0 to 3]	22.447	14.513
Total MW generation at Mackay	-0.700	-0.478
Total nominal MVAr shunt capacitors on line within nominated Ross area locations (2)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (3)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (4)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (5)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (6)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (7)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (8)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (8)	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) 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

(3) 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

(4) 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

(5) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:
Strathmore 275kV 1 x 84MVAr

(6) 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

(7) 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

(8) 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 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 120MVAr capacitor banks available at Gin Gin [0 to 1]	63.5367
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, Oakey, Millmerran and Terranora Interconnector and 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.4 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1 Calvale-Halys contingency	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 generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran 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) 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 $= \dfrac{\text{Zone reactive demand}}{\text{active demand}} \times 100$

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.5 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 $= \dfrac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(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 2018/19, 2019/20 and 2020/21.

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 Table 6.1 (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). Minimum short circuit currents are also important in ensuring power system quality and stability and for ensuring the proper operation of protection systems.

Additional to this information, Powerlink provides information in the Generation Capacity Guide on the capacity available to connect new non-synchronous generators.

Tables E.1 to E.3 show indicative minimum symmetrical three phase short circuit currents at Powerlink's substations. These indicative minimum short circuit currents were calculated by analysing half hourly system normal snapshots over the period 1 April 2017 and 31 March 2018. The minimum of subtransient, transient and synchronous short circuit currents over the year were compiled for each substation, with the individual outage of each significant network element.

Minimum system normal short circuit currents are also included, based on the same methodology, instead with all network elements in-service. These short circuit currents could be used to calculate connection capacity for proponents who would be willing to reduce capacity for specific network outages.

These minimum short circuit currents are indicative only, and are based on history. Short circuit currents can be lower for different generation dispatches and/or network elements out of service.

Table E.1 Indicative short circuit currents – northern Queensland –2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.2	3.8	13.2	13.6	13.3	13.7	13.3	13.7
Alligator Creek	132	25.0	3.0	1.7	4.6	6.0	4.6	6.0	4.6	6.0
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	2.0	0.5	2.2	2.5	2.2	2.5	2.2	2.5
Cairns (2T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.7	0.7	5.9	7.8	5.9	7.9	5.9	7.9
Cardwell	132	19.3	1.6	0.9	3.0	3.3	3.0	3.3	3.0	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	3.0	2.3	6.6	7.6	6.7	7.7	6.7	7.7
Clare South	132	40.0	3.4	2.9	7.9	8.1	7.9	8.1	7.9	8.1
Collinsville North	132	31.5	4.4	2.3	8.6	9.5	8.7	9.6	8.7	9.6
Coppabella	132	31.5	2.2	1.4	3.0	3.4	3.1	3.4	3.1	3.4
Crush Creek	275	40.0	-	-	9.1	10.4	9.4	10.7	9.4	10.7
Dan Gleeson (1T)	132	31.5	4.2	3.6	12.5	13.0	12.6	13.1	12.6	13.1
Dan Gleeson (2T)	132	40.0	4.2	3.6	12.5	12.9	12.6	13.0	12.6	13.0
Edmonton	132	40.0	2.5	0.8	5.3	6.5	5.4	6.6	5.4	6.6
Eagle Downs	132	40.0	2.9	1.5	4.4	4.3	4.5	4.4	4.5	4.4
El Arish	132	40.0	2.1	1.0	3.2	4.0	3.2	4.0	3.2	4.0
Garbutt	132	40.0	3.9	1.9	10.9	10.8	10.9	10.9	10.9	10.9
Goonyella Riverside	132	40.0	3.4	2.9	5.7	5.3	5.9	5.4	5.9	5.4
Haughton	275	40.0	-	-	-	-	7.1	7.0	7.1	7.0
Ingham South	132	31.5	1.8	0.7	3.2	3.1	3.2	3.1	3.2	3.1
Innisfail	132	40.0	1.9	1.2	2.9	3.5	2.9	3.5	2.9	3.5
Invicta	132	19.3	2.6	1.7	5.3	4.7	5.3	4.7	5.3	4.7
Kamerunga	132	15.3	2.3	0.8	4.5	5.4	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.7	2.1	5.7	6.3	5.7	6.4	5.7	6.4
Kemmis	132	31.5	3.9	1.7	6.0	6.6	6.1	6.7	6.1	6.7
King Creek	132	40.0	2.9	1.4	4.7	3.9	4.7	4.0	4.7	4.0
Lake Ross	132	31.5	-	-	17.1	19.1	17.4	19.4	17.4	19.4
Mackay (2T)	132	10.9	3.4	2.9	4.9	5.7	4.8	5.5	4.8	5.5
Mackay (1T & 3T)	132	10.9	3.4	2.9	4.7	5.1	4.3	4.1	4.3	4.1

Table E.1 Indicative short circuit currents – northern Queensland –2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Mackay Ports	132	40.0	2.5	1.5	3.5	4.2	3.5	4.2	3.5	4.2
Mindi	132	40.0	3.2	3.0	4.5	3.6	4.5	3.7	4.5	3.7
Moranbah	132	10.9	3.9	3.1	7.4	8.8	7.9	9.3	7.9	9.3
Moranbah South	132	31.5	3.2	2.6	5.4	5.0	5.7	5.2	5.7	5.2
Mt McLaren	132	31.5	1.5	1.4	2.0	2.2	2.1	2.2	2.1	2.2
Nebo	275	31.5	4.0	3.5	10.3	10.6	10.6	10.9	10.6	10.9
Nebo	132	15.3	6.7	5.9	13.5	15.6	13.9	15.9	13.9	15.9
Newlands	132	25.0	2.4	1.3	3.5	3.9	3.5	3.9	3.5	3.9
North Goonyella	132	20.0	2.8	1.0	4.3	3.7	4.4	3.7	4.4	3.7
Oonooie	132	31.5	2.3	1.4	3.2	3.7	3.2	3.7	3.2	3.7
Peak Downs	132	31.5	2.7	1.6	4.0	3.6	4.1	3.7	4.1	3.7
Pioneer Valley	132	31.5	4.0	3.5	7.1	7.9	7.1	7.8	7.1	7.8
Proserpine	132	40.0	2.2	1.5	2.8	3.3	2.8	3.4	2.8	3.4
Ross	275	31.5	2.7	2.3	8.2	9.1	8.5	9.5	8.5	9.5
Ross	132	31.5	4.8	4.3	17.6	19.9	17.9	20.2	17.9	20.2
Springlands	132	40.0	-	-	9.4	10.6	9.5	10.7	9.5	10.7
Stony Creek	132	40.0	2.5	1.2	3.6	3.5	3.6	3.5	3.6	3.5
Strathmore	275	31.5	3.2	2.8	9.2	10.5	9.5	10.9	9.5	10.9
Strathmore	132	40.0	4.8	2.2	9.6	11.1	9.8	11.2	9.8	11.2
Townsville East	132	40.0	4.0	1.6	12.8	12.4	12.8	12.5	12.8	12.5
Townsville South	132	21.9	4.4	3.9	17.1	20.7	17.3	20.9	17.3	20.9
Townsville PS	132	31.5	3.6	2.5	10.5	11.1	10.6	11.2	10.6	11.2
Tully	132	31.5	2.4	1.9	4.0	4.2	4.0	4.2	4.0	4.2
Turkinje	132	20.0	1.7	1.1	2.9	3.2	2.9	3.3	2.9	3.3
Walkamin	275	40.0	-	-	3.2	3.6	3.2	3.6	3.2	3.6
Wandoo	132	31.5	3.2	3.0	4.5	3.3	4.5	3.3	4.5	3.3
Woree (1T)	275	40.0	1.3	0.9	2.8	3.2	2.8	3.3	2.8	3.3
Woree (2T)	275	40.0	1.3	0.9	2.9	3.3	2.9	3.3	2.9	3.3
Wotonga	132	40.0	3.5	1.7	5.9	6.9	6.2	7.1	6.2	7.1
Yabulu South	132	40.0	4.1	3.7	12.5	12.0	12.7	12.0	12.7	12.0

Table E.2 Indicative short circuit currents – central Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Baralaba	132	15.3	3.3	1.4	4.2	3.6	4.2	3.6	4.2	3.6
Biloela	132	20.0	3.5	0.9	7.8	8.1	7.9	8.1	7.9	8.1
Blackwater	132	10.9	4.0	3.0	5.3	6.5	6.3	7.5	6.3	7.5
Bluff	132	40.0	2.5	2.1	3.3	4.1	3.6	4.5	3.6	4.5
Bouldercombe	275	31.5	7.2	6.4	20.0	19.4	20.3	19.6	20.3	19.6
Bouldercombe	132	21.8	8.1	4.7	11.5	13.6	11.6	13.6	11.6	13.6
Broadsound	275	31.5	5.1	4.3	11.7	9.1	12.2	9.3	12.2	9.3
Callemondah	132	31.5	11.0	5.6	22.4	25.0	22.5	25.0	22.5	25.0
Calliope River	275	40.0	7.6	6.8	20.8	23.7	21.0	23.9	21.0	23.9
Calliope River	132	40.0	11.7	9.7	25.1	30.2	25.2	30.3	25.2	30.3
Calvale	275	31.5	7.5	6.7	23.4	25.8	23.5	26.0	23.5	26.0
Calvale (1T)	132	31.5	5.3	1.0	8.7	9.6	8.8	9.6	8.8	9.6
Calvale (2T)	132	31.5	-	-	8.4	9.2	8.4	9.3	8.4	9.3
Dingo	132	31.5	2.1	1.2	2.7	3.0	2.8	3.1	2.8	3.1
Duaringa	132	40.0	1.7	1.1	2.2	2.9	2.3	3.0	2.3	3.0
Dysart	132	10.9	3.1	1.8	4.4	5.1	4.6	5.4	4.6	5.4
Egans Hill	132	25.0	5.5	1.6	7.3	7.4	7.3	7.5	7.3	7.5
Gladstone PS	275	40.0	7.3	6.5	19.4	21.6	19.6	21.7	19.6	21.7
Gladstone PS	132	40.0	10.7	9.0	22.1	25.2	22.1	25.3	22.1	25.3
Gladstone South	132	40.0	9.1	7.5	16.4	17.3	16.4	17.3	16.4	17.3
Grantleigh	132	31.5	2.1	1.8	2.6	2.8	2.6	2.7	2.6	2.7
Gregory	132	31.5	5.6	4.7	8.6	10.0	9.8	11.0	9.8	11.0
Larcom Creek	275	40.0	6.6	3.0	15.4	15.3	15.5	15.4	15.5	15.4
Larcom Creek	132	40.0	6.9	3.8	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.3	2.6	5.6	5.6	6.1	6.0	6.1	6.0
Lilyvale	132	25.0	5.8	4.8	9.0	10.7	10.3	11.9	10.3	11.9
Moura	132	12.3	2.8	1.1	3.9	4.2	3.9	4.2	3.9	4.2
Norwich Park	132	31.5	2.7	1.1	3.3	2.5	3.4	2.5	3.4	2.5
Pandoin	132	40.0	4.9	1.2	6.2	5.8	6.2	5.8	6.2	5.8
Raglan	275	40.0	5.9	3.7	11.9	10.4	12.0	10.4	12.0	10.4
Rockhampton (1T)	132	10.9	4.5	1.7	5.8	6.0	5.8	6.0	5.8	6.0
Rockhampton (5T)	132	10.9	4.4	1.7	5.6	5.8	5.7	5.8	5.7	5.8

Table E.2 Indicative short circuit currents – central Queensland – 2018/19 to 2020/21 *(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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklands	132	31.5	5.2	3.5	6.8	6.1	6.8	6.1	6.8	6.1
Stanwell	275	31.5	7.3	6.7	22.7	24.2	23.0	24.5	23.0	24.5
Stanwell	132	31.5	4.2	3.1	5.4	6.0	5.4	6.0	5.4	6.0
Wurdong	275	31.5	7.1	5.6	16.8	16.7	16.8	16.6	16.8	16.6
Wycarbah	132	40.0	3.4	2.6	4.2	5.1	4.2	5.1	4.2	5.1
Yarwun	132	40.0	6.8	4.2	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	6.7	5.6	18.1	18.6	18.2	18.7	18.2	18.7
Abermain	110	31.5	12.2	10.0	21.4	25.2	21.4	25.3	21.4	25.3
Algester	110	40.0	12.2	11.0	21.5	21.2	21.6	21.2	21.6	21.2
Ashgrove West	110	26.3	11.5	9.1	19.1	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	6.6	5.9	16.8	18.5	16.9	18.6	16.9	18.6
Belmont	110	37.4	14.7	13.2	29.8	37.0	29.9	37.1	29.9	37.1
Blackstone	275	40.0	6.9	6.2	21.0	23.3	21.2	23.4	21.2	23.4
Blackstone	110	40.0	13.4	12.1	25.3	29.0	25.4	29.0	25.4	29.0
Blackwall	275	37.0	7.2	6.4	22.2	24.0	22.4	24.1	22.4	24.1
Blythdale	132	40.0	3.3	2.4	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	6.0	5.3	23.4	25.4	23.6	25.6	23.6	25.6
Braemar (East)	275	40.0	6.9	4.7	26.8	31.0	26.9	31.1	26.9	31.1
Braemar (West)	275	40.0	6.8	4.4	27.2	29.9	27.3	30.0	27.3	30.0
Bulli Creek	330	50.0	6.2	3.6	18.3	14.5	18.4	14.5	18.4	14.5
Bulli Creek	132	40.0	3.1	2.9	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	10.6	7.6	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	5.3	4.3	8.0	7.8	7.9	7.8	7.9	7.8
Clifford Creek	132	40.0	4.3	3.5	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.2	4.2	12.4	11.7	12.5	11.7	12.5	11.7
Columboola	132	25.0	7.9	6.3	16.1	18.2	16.1	18.2	16.1	18.2
Condabri North	132	40.0	7.1	5.8	13.1	12.1	13.1	12.1	13.1	12.1
Condabri Central	132	40.0	5.7	4.7	8.9	6.6	8.9	6.6	8.9	6.6
Condabri South	132	40.0	4.5	3.8	6.5	4.4	6.5	4.4	6.5	4.4
Coopers Gap	275	40.0	-	-	-	-	17.5	15.8	17.5	15.8
Dinoun South	132	40.0	4.8	3.8	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.9	3.6	6.9	8.4	6.9	8.4	6.9	8.4
Fairview	132	40.0	3.2	2.6	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	4.0	3.1	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.1	5.5	10.9	10.1	9.2	8.6	9.2	8.6
Gin Gin	132	20.0	8.1	6.2	12.8	13.9	12.0	13.0	12.0	13.0

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21

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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Goodna	275	40.0	6.5	5.2	16.1	16.0	16.2	16.0	16.2	16.0
Goodna	110	40.0	13.5	12.1	25.4	27.5	25.4	27.5	25.4	27.5
Greenbank	275	40.0	6.9	6.2	20.3	22.5	20.5	22.6	20.5	22.6
Halys	275	50.0	8.0	7.1	31.8	25.9	32.5	27.6	32.5	27.6
Kumbarilla Park (1T)	275	40.0	6.0	1.7	16.7	16.1	16.7	16.1	16.7	16.1
Kumbarilla Park (2T)	275	40.0	6.0	1.7	16.7	16.1	16.7	16.1	16.7	16.1
Kumbarilla Park	132	40.0	8.4	5.7	13.2	15.2	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.3	5.5	14.9	15.4	14.9	15.5	14.9	15.5
Loganlea	110	31.5	13.1	11.8	22.8	27.4	22.9	27.5	22.9	27.5
Middle Ridge (4T)	330	50.0	5.2	3.2	12.6	12.3	12.7	12.3	12.7	12.3
Middle Ridge (5T)	330	50.0	5.3	3.2	13.0	12.7	13.1	12.7	13.1	12.7
Middle Ridge	275	31.5	6.7	6.0	18.1	18.3	18.3	18.4	18.3	18.4
Middle Ridge	110	18.3	10.7	9.0	21.0	24.8	21.3	25.2	21.3	25.2
Millmerran	330	40.0	5.8	5.2	18.4	19.8	18.5	19.8	18.5	19.8
Molendinar (1T)	275	40.0	4.7	2.1	8.3	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	4.7	2.1	8.3	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	11.7	10.2	20.0	25.3	19.3	24.5	19.3	24.5
Mt England	275	31.5	7.1	6.3	22.5	22.8	22.7	22.9	22.7	22.9
Mudgeeraba	275	31.5	5.0	4.2	9.4	9.4	9.3	8.6	9.3	8.6
Mudgeeraba	110	25.0	10.9	10.0	18.7	22.8	17.4	21.0	17.4	21.0
Murarrie (1T)	275	40.0	6.0	2.5	13.1	13.5	13.2	13.5	13.2	13.5
Murarrie (2T)	275	40.0	6.0	2.5	13.1	13.6	13.2	13.7	13.2	13.7
Murarrie	110	40.0	13.5	12.2	24.4	29.4	24.4	29.5	24.4	29.5
Oakey Gt Ps	110	31.5	5.1	1.2	11.3	12.4	11.3	12.4	11.3	12.4
Oakey	110	40.0	4.9	1.3	10.1	10.1	10.1	10.0	10.1	10.0
Orana	275	40.0	5.7	3.4	14.9	13.7	15.0	13.7	15.0	13.7
Palmwoods	275	31.5	5.2	3.4	8.4	8.8	8.5	9.0	8.5	9.0
Palmwoods	132	21.9	9.1	6.8	13.0	15.5	13.1	15.8	13.1	15.8
Palmwoods (7T)	110	40.0	5.9	2.8	7.2	7.5	7.3	7.6	7.3	7.6
Palmwoods (8T)	110	40.0	5.9	2.8	7.2	7.5	7.3	7.6	7.3	7.6
Redbank Plains	110	31.5	12.2	9.2	21.3	20.8	21.4	20.8	21.4	20.8
Richlands	110	40.0	12.4	10.7	22.1	22.7	22.1	22.8	22.1	22.8

Table E.3 Indicative short circuit currents – southern Queensland – 2018/19 to 2020/21 *(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					
					2018/19		2019/20		2020/21	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (1T)	275	31.5	6.0	2.4	13.2	12.3	13.2	12.3	13.2	12.3
Rocklea (2T)	275	31.5	5.0	2.4	8.7	8.4	8.8	8.4	8.8	8.4
Rocklea	110	31.5	13.5	12.1	24.9	28.7	25.0	28.7	25.0	28.7
Runcorn	110	40.0	11.5	8.5	19.4	19.6	19.4	19.7	19.4	19.7
South Pine	275	31.5	7.0	6.3	18.6	21.1	18.8	21.3	18.8	21.3
South Pine (East)	110	40.0	12.9	11.4	21.5	27.5	21.6	27.6	21.6	27.6
South Pine (West)	110	40.0	12.3	10.0	20.4	23.5	20.5	23.5	20.5	23.5
Sumner	110	40.0	12.0	8.9	20.6	20.3	20.7	20.3	20.7	20.3
Swanbank E	275	40.0	6.9	6.2	20.7	22.8	20.9	22.9	20.9	22.9
Tangkam	110	31.5	5.9	4.0	13.3	12.4	13.4	12.4	13.4	12.4
Tarong (1)	275	31.5	8.1	7.1	33.3	34.7	33.9	35.6	33.9	35.6
Tarong (1T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	11.7	7.1	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	4.8	3.2	7.3	7.2	7.4	7.1	7.4	7.1
Teebar Creek	132	40.0	7.6	6.0	10.1	11.2	10.8	11.6	10.8	11.6
Tennyson	110	40.0	10.4	1.7	16.2	16.4	16.3	16.4	16.3	16.4
Upper Kedron	110	40.0	12.3	10.9	21.2	18.7	21.2	18.7	21.2	18.7
Wandoan South	275	40.0	4.0	3.2	7.1	7.7	7.1	7.7	7.1	7.7
Wandoan South	132	40.0	5.4	4.0	8.6	11.0	8.6	11.0	8.6	11.0
West Darra	110	40.0	13.3	12.0	24.9	23.8	24.9	23.9	24.9	23.9
Western Downs	275	40.0	6.6	4.9	25.2	24.5	25.4	24.7	25.4	24.7
Woolooga	275	31.5	5.7	4.9	9.6	10.9	10.0	11.2	10.0	11.2
Woolooga	132	20.0	9.2	7.8	13.0	15.3	13.4	15.7	13.4	15.7
Yuleba North	275	40.0	3.5	2.9	5.8	6.4	5.8	6.4	5.8	6.4
Yuleba North	132	40.0	5.5	4.3	7.7	9.4	7.7	9.4	7.7	9.4

Note:

(1) The lowest rated plant at this location is required to withstand and/or interrupt a short circuit current which is less than the maximum short circuit current and below the plant rating.

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

<table>
<tr><th>Potential project</th><th>Indicative cost (most likely network option)</th><th>Zone</th><th>Indicative non-network requirement</th><th>Possible commissioning date</th><th>TAPR Reference</th></tr>
<tr><td colspan="6">Transmissmion line</td></tr>
<tr><td>Line refit works on the coastal 132kV transmission line between Clare South and Townsville South substations</td><td>$25m</td><td>Ross</td><td rowspan="2">Up to 10MW and 1,000MWh in the Proserpine or Collinsville area</td><td rowspan="2">June 2021</td><td rowspan="2">S5.7.2</td></tr>
<tr><td>Retirement of the inland 132kV transmission line between Clare South and Townsville South substations and installation of a transformer at Strathmore Substation</td><td>$15m (1)</td><td>Ross</td></tr>
<tr><td>Line refit works on the 132kV transmission line between Eton tee and Pioneer Valley Substation</td><td>$8m</td><td>North</td><td>Up to 10MW and 50MWh per day in the Mackay or Pioneer Valley area</td><td>June 2023</td><td>S5.7.3</td></tr>
<tr><td>Line refit works on the 132kV transmission line between Egans Hill and Rockhampton substations</td><td>$14m</td><td>Central West</td><td>Proposals which may significantly contribute to reducing the requirements in the transmission network into the Rockhampton area of up to 100MW</td><td>December 2020</td><td>S5.7.4</td></tr>
<tr><td>Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations</td><td>$5m</td><td>Gladstone</td><td>Up to 180MW and approximately 3,200MWh per day</td><td>June 2019</td><td>S5.7.4</td></tr>
<tr><td>Line refit works on the 110kV transmission lines between South Pine to Upper Kedron</td><td rowspan="2">$24m</td><td rowspan="2">Moreton</td><td>In excess of 150MW in the CBD and inner west suburbs of Brisbane</td><td rowspan="2">June 2021</td><td rowspan="2">S5.7.9</td></tr>
<tr><td>Line refit works on the 110kV transmission lines between Rocklea, Sumner and West Darra</td><td>In excess of 150MW in the south west suburbs of Brisbane</td></tr>
</table>

Note:

(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.

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
Targeted line refit works on sections of the 275kV transmission lines between Greenbank and Mudgeeraba substations	$20m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission network into to the southern Gold Coast and northern NSW area of over 250MW	December 2025	5.7.10
Substations - primary plant and secondary systems					
Kamerunga 132kV Substation replacement	$21m	Far North	Up to 60MW and 900MWh per day on a continuous basis in the northern Cairns region	June 2021	S5.7.1
Woree 275/132kV and SVC secondary systems replacement	$19m	Far North	Proposals which may significantly contribute to reducing the requirements in the Far North region. Currently over 250MW at peak is injected via Woree Substation	June 2022	S5.7.1
Cairns 132kV secondary systems replacement	$8m	Far North	Up to 65MW and 1,000MWh per day in the Cairns area	June 2023	S5.7.1
Dan Gleeson 132kV secondary systems replacement	$5m	Ross	Up to 50MW and 850MWh per day in the vicinity of Dan Gleeson	December 2020	S5.7.2 RIT-T in progress
Townsville South 132kV primary plant and secondary systems replacement	$12m	Ross	Proposals which may significantly contribute to reducing the requirements in the Townsville area of over 200MW at peak, as well as providing connection for over 450MW of generation	December 2021	S5.7.2
Ross 275/132kV primary plant replacement	$24m	Ross	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Townsville area of up to 400MW	December 2022	S5.7.2
North Goonyella 132kV secondary systems replacement	$2m	North	Up to 21MW and approximatley 415MWh	December 2020	S5.7.3
Kemmis 132kV secondary systems replacement	$8m	North	Injection or demand response of up to 32MW on a continuous basis, and up to 760MWh per day	June 2023	S5.7.3
Newlands 132kV primary plant replacement	$4m	North	Up to 23MW and approximately 460MWh	June 2023	S5.7.4

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
Baralaba secondary systems replacement	$8m	Central West	Injection at Moura of up to 36MW or a reduction of 36MW or 34MWH per day at Moura and Biloela	December 2020	S5.7.4 RIT-T in progress
Lilyvale 275/132kV primary plant replacement	$9m	Central West	Proposals which may significantly contribute to reducing the requirements in the transmission network into the central west and northern Bowen Basin area of up to 370MW	June 2021	S5.7.4
Bouldercombe 275/132kV primary plant replacement	$26m	Central West	Injection at either Bouldercombe, or closer to the loads on the Energy Queensland 66kV network, of up to 275MW	December 2022	S5.7.4
Blackwater 132kV secondary systems replacement	$5m	Central West	Up to 260MW and approximately 2,650MWh per day	June 2023	S5.7.4
QAL West 132kV secondary systems replacement	$5m	Gladstone	Up to 40MW and approximately 800MWh	December 2022	S5.7.4
Gladstone South 132kV secondary systems replacement	$15m	Gladstone	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Gladstone area of up to 200MW	June 2023	S5.7.4
Tarong 66kV Cable Replacement	$3m	South West	Up to 24MW and approximately 200MWh per day	June 2019	S5.7.6
Tarong 275kV secondary systems replacement	$11m	South West	Proposals which may significantly contribute to reducing the requirements in the transmission network into the South West zone of over 55MW at peak as well as providing connection for over 2,000MW of generation and power transfer capacity of over 3,600MW	December 2021	S5.7.6

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
Palmwoods 275kV secondary systems replacement	$7m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into South-East Queensland, as well as providing injection to Energex for the Sunshine Coast and Caboolture areas of over 400MW	June 2021	S5.7.9
Belmont 275kV secondary systems replacement	$9m	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 700MW	December 2020	S5.7.9
Abermain 110kV secondary systems replacement	$7m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into the Ipswich, Lockrose, Gatton areas and into the south-western suburbs of Brisbane of over 200MW	June 2021	S5.7.9
Redbank Plains 110kV primary plant replacement	$3m	Moreton	Up to 25MW and approximately 350MWh per day	June 2022	S5.7.9
Murarrie 110kV secondary systems replacement	$25m	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 2023	S5.7.9
Mudgeeraba 275kV secondary systems replacement	$16m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area of over 250MW	December 2021	S5.7.10

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					
Ingham South 132/66kV transformers replacement	$6m	Ross	Up to 20MW and 300MWh per day on a continuous basis: Installation of one transformer only and either: (i) non-network of up to 20MW and 300MWh per day (ii) dynamic voltage support of up to 15MVAr, and network support of up to 10MW and 110MWh per day	December 2019	5.7.2 RIT-T in progress
Kemmis 132/66kV transformer replacement	$4m	North	Up to 32MW and approximately 760MWh per day	December 2020	S5.7.3
Lilyvale 132/66kV transformers replacement	$10m	Central West	Up to 120MW and approximately 1,700MWh per day, or up to 25MW and 300MWh per day (to support two smaller transformers)	June 2021	S5.7.4
Bouldercombe 275/132kV transformers replacement	$7m	Central West	Injection at either Bouldercombe, or closer to the loads on the Ergon Energy 66kV network, of up to 275MW and 3,500MWh per day	June 2021	S5.7.4
Blackwater 132/66/11kV transformers replacement	$5m	Central West	Provide support to the Ergon Energy 66kV network of up to 160MW and 2,000MWh per day in the Blackwater area	June 2022	S5.7.4
Redbank Plains 110/11kV transformers replacement	$5m	Moreton	Up to 25MW and approximately 350MWh per day	June 2024	S5.7.9

Appendix G — Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
BSL	Boyne Smelter Limited
CAA	Connection and Access Agreement
CBD	Central Business District
CEH	Clean Energy Hub
COAG	Council of Australian Governments
CPI	Consumer Price Index
CQ	Central Queensland
CQ-SQ	Central Queensland to Southern Queensland
CQ-NQ	Central Queensland to North Queensland
CSG	Coal Seam Gas
DCA	Dedicated Connection Assets
DER	Disbributed Energy Resources
DILGP	Department of Infrastructure, Local Government and Planning
DNRME	Deparment of Natural Resources, Mines and Energy
DNSP	Distribution Network Service Provider
DSM	Demand Side Management
EDQ	Economic Development Queensland
EFI	AEMO's Electricity Forecast Insights
EII	Energy Infrastructure Investments
EMS	Energy Management System
EOI	Expression of Interest
ESOO	Electricity Statement of Opportunity
EV	Electric vehicles
EY	Ernst & Young
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FIT	Feed-in tariff

FNQ	Far North Queensland
GFC	Global Financial Crisis
GIS	Geospatial Information Systems
GSP	Gross State Product
GWh	Gigawatt hour
HV	High Voltage
HVDC	High Voltage Direct Current
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovoltage
LNG	Liquified Natural Gas
LTTW	Lightning Trip Time Window
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNESR	Non-network Engagement Stakeholder Register
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
NWD	Non-weather dependent

Appendix G - Glossary *(continued)*

OFGS	Over Frequency Generation Shedding
PoE	Probability of Exceedance
PSITAG	Power System Issues Technology Advisory Group
PS	Power Station
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
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
	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rates of change of frequency
RTA	Rio Tino Aluminium
SCR	Short Circuit Ratio
SDA	State Development Area
SEQ	South East Queensland
SAET	South Australian Energy Transformation
SPS	Special Protection Scheme
SQ	South Queensland
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VRE	Variable renewable energy
VSC	Voltage Source Converter
WD	Weather dependent