



ASSET MANAGEMENT DISTRIBUTION ANNUAL PLANNING REPORT 2022

December 2022

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DISCLAIMER

Essential Energy is registered as a Distribution Network Service Provider. This Distribution Annual Planning Report 2022 has been prepared and published by Essential Energy under clause 5.12.2 and 5.13.2 of the National Electricity Rules to notify Registered Participants and Interested Parties of the results of the distribution network annual planning review and should only be used for those purposes.

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Contact

For all enquiries regarding the Distribution Annual Planning Report 2022 and for making written submissions contact:

Essential Energy
DM Coordinator
PO Box 5730
Port Macquarie NSW 2444
Email: dmcoordinator@essentialenergy.com.au

EXECUTIVE SUMMARY

Since 1 January 2013, the National Electricity Rules (NER) have stated that all Distribution Network Service Providers (DNSPs) operating in the National Electricity Market (NEM) are required to:

- Conduct an annual planning review and publish a Distribution Annual Planning Report (DAPR)
- Conduct economic assessments of potential project options under a new Regulatory Investment Test for Distribution (RIT-D)
- Implement a Demand Side Engagement Strategy to consult with and engage non-network providers in the development and evaluation of potential solutions to identified network needs.

The annual planning review includes the planning for all assets and activities carried out by Essential Energy that would materially affect the performance of its network. This includes planning activities associated with the replacement and refurbishment of assets and negotiated services. The objective of the annual planning review is to enable DNSPs to plan for and adequately address possible future issues in a timely manner. The outcome of the annual planning review is the DAPR.

Essential Energy is required to prepare and publish a DAPR that is compliant with the requirements of the NER (Section 5.13.2 and Schedule 5.8) to:

- Provide transparency to Essential Energy's decision-making processes and provide a level playing field for all regions in the NEM in terms of attracting investment and promoting efficient decisions
- Set out the results of Essential Energy's annual planning review, including joint planning, covering a minimum five year forward planning period for distribution assets
- Inform registered participants and interested parties on the annual planning review outcomes - report on capacity and load forecasts for sub-transmission lines, zone substations and transmission-distribution connection points, plus, where they have been identified, any primary distribution feeders which were overloaded or forecast to be overloaded within the next two years
- Provide information on Essential Energy's demand management activities and actions taken to promote non-network initiatives each year, and plans for demand management and embedded generation over the forward planning period
- Assist non-network providers, Transmission Network Service Providers (TNSPs), DNSPs and connection applicants to make efficient investment decisions.

The DAPR covers a minimum five year forward planning period for distribution network assets.

Amendment History

V1 – Issued December 2022
- Initial Release

1. INTRODUCTION

1.1 About Essential Energy

Essential Energy's purpose is '*enabling energy solutions that improve life*', with a vision to be '*empowering communities to share and use energy for a better tomorrow*'.

The organisation operates and maintains one of Australia's largest electricity networks, across 95 per cent of New South Wales (NSW) and parts of southern Queensland. Serving more than 880,000 customers – including homes, hospitals, schools, businesses, and community services – Essential Energy is an economic enabler for regional, rural, and remote communities.

Essential Energy aims to continuously improve safety performance for employees, contractors, and the community, along with the reliability, security, and cost efficiency of the network, while striving to maintain downward pressure on the network component of customers' electricity bills and deliver an acceptable Return on Capital Employed.

Essential Energy's business objectives are:

- Continuous improvements in safety culture and performance
- Operate at industry best practice for efficiency, delivering best value for customers
- Deliver real reductions in customers' distribution network charges
- Deliver a satisfactory Return on Capital Employed
- Reduce the environmental impact of Essential Energy where it is efficient to do so.

These will be achieved through enhanced customer engagement; investing in best practice systems, processes and technology; improving commercial capabilities to enable the business to operate safely and efficiently; and taking a more holistic approach to the sustainability of our operations.

Essential Energy's network area is divided into ten operations areas encompassing a wide range of geographical, climatic, and environmental conditions.

In the Far West of NSW, an operating division, Essential Water, services a population of approximately 18,000 people. A secure water supply is delivered to around 10,500 customers in Broken Hill, Sunset Strip, Menindee, and Silverton, as well as rural customers. Reliable sewerage services are provided to around 9,600 customers in Broken Hill. Essential Water operates a network of dams, water treatment plants, sewage treatment plants, reservoirs, water, and sewage pumping stations, mains, and other related infrastructure.

1.1.1 Operating Environment

Essential Energy is a NSW Statutory State Owned Corporation and Energy Services Corporation, regulated by state and national statutory and legislative requirements. In addition to being subject to specific electricity distribution laws and rules, Essential Energy is subject to most of the statutory and other legal requirements that other businesses are subject to, including workplace health and safety (WHS), environmental, competition, industrial, consumer protection and information laws. Essential Energy is also required to follow government and regulatory direction.

At a national level, Essential Energy is subject to the National Electricity Law (NEL) and the National Electricity Rules (NER) which regulate the National Electricity Market (NEM). Essential Energy operates in the NEM as a Distribution Network Service Provider (DNSP). The Australian Energy Regulator (AER) regulates the transmission and distribution sectors of the NEM under the NEL and NER.

At a state level, Essential Energy's activities are governed by the NSW Electricity Supply Act 1995, the Energy Services Corporations Act 1995 and a NSW Distribution Network Service Provider licence. The Independent Pricing and Regulatory Tribunal (IPART) is responsible for monitoring compliance with licence conditions.

Essential Energy ensures compliance with these laws and regulations through its internal codes and policies and a common control framework, which comprises plans, policies, procedures, delegations, instruction and training, audits of compliance and risk management. Operations are guided by policies and codes, including Health, Safety and Environment Policy, Statement of Business Ethics, and Code of Conduct.

1.1.2 Essential Energy Statistics

Table 1 – Essential Energy Statistics for 2021/22

Category	Number at 30/6/2022
Distribution Customer Numbers (Total)	881,693
Customer Numbers (Coastal)	118,371
Customer Numbers (Ranges)	58,471
Customer Numbers (Mid North Coast)	175,965
Customer Numbers (Northern Tablelands)	81,665
Customer Numbers (North Western)	28,809
Customer Numbers (Macquarie)	101,919
Customer Numbers (Riverina Slopes)	77,852
Customer Numbers (South Eastern)	121,202
Customer Numbers (Murray)	68,908
Customer Numbers (Central)	48,531
Maximum Demand (MW)	2,420
Feeder Number CBD	0
Feeder Number Urban	280
Feeder Number Short Rural	942
Feeder Numbers Long Rural	244
Energy Received by Distribution Network to Year End GWh	13,114
Energy Distributed (Residential) GWh	4,806
Energy Distributed (Non-Residential including un-metered supplies) GWh	7,646
Energy Distributed (Coastal) GWh	814
Energy Distributed (Ranges) GWh	763
Energy Distributed (Mid North Coast) GWh	1,442
Energy Distributed (Northern Tablelands) GWh	1,167
Energy Distributed (North Western) GWh	326
Energy Distributed (Macquarie) GWh	3,389
Energy Distributed (Riverina Slopes) GWh	1,247
Energy Distributed (South Eastern) GWh	1,174
Energy Distributed (Murray) GWh	938
Energy Distributed (Central) GWh	1,191
System Loss Factor (%)	5.05
Substation - Zone (Number) ¹	339
Substation - Distribution (Number)	140,153
High Voltage Overhead (km)	157,702

¹ The number of zone substations reported include only those sites where the forecast is published within this document.

Category (Continued)	Number at 30/6/2022
High Voltage Underground (km)	2,964
Low Voltage Overhead (km) ²	25,354
Low Voltage Underground (km)	7,102
Pole (Number) ³	1,337,686
Streetlights (Number)	165,512

Notes: Distances for overhead and underground lines are circuit km.

1.2 Essential Energy's Network



Figure 1 – Essential Energy's Network Area

Essential Energy's network includes 183,057km of overhead powerlines traversing 737,000 square kilometres of landmass. The network has a large number of asset types across different voltage levels. Customers can be connected at any voltage level from 220,000 volts down to low voltage (400/230 volts), depending on their power

² LV Services and Streetlight circuits excluded, LV Services classification only includes the last span from the pole to the Point of Attachment, and no longer includes the road crossing section.

³ This number is the sum of urban, short rural and long rural poles published in the annual RIN.

needs. Figure 2 illustrates the variety of network components owned by Essential Energy, with shaded portions showing examples of connected customers and bulk supply points not owned by Essential Energy – the distribution network is one component of an integrated system by which electricity is generated, transmitted and distributed to customers.

The majority of costs associated with electricity distribution are not driven by the number of customers or their demand on the network. Rather, network costs are driven by the number of assets required to deliver electricity to each customer. Whether there are 50 customers connected to one pole or 50 poles connecting one customer, each asset needs to be inspected, safely maintained and replaced at the end of its life.

1.2.1 Number and Types of Distribution Assets

Essential Energy's network consists of 183,057km of overhead sub-transmission, high voltage distribution and low voltage distribution power lines, 10,066km of underground cables and over 1.3 million poles. Approximately 95 per cent of the network is of an overhead construction type and 95 per cent of distribution substations are pole-mounted due to the predominately rural nature of the network.

The majority of the distribution network is radial, with most parts supplied from one source. This provides little opportunity for interconnection with other circuits for security and supply continuity when performing maintenance activities or in the event of unplanned outages. This is equally true of the radial 132,000 volt and 66,000 volt sub-transmission networks.

Essential Energy reviews the level of reliability received by our customers against the nationally defined Value of Customer Reliability (VCR) and ensures that the level of network investment is in line with this measure of customer expectation. This approach does limit the level of reliability able to be delivered to our remote customers, primarily due to the level of investment required. Essential Energy is, however, committed to continually reviewing the reliability of its network in all parts of its supply area. Where suitable, Essential Energy will aim to utilise available technologies and appropriate practices to provide the maximum reliability and security of supply possible within these constraints.

Table 2 – Network Assets as at 30 June 2022

ASSETS	Circuit kilometres		Transformers	
	Overhead lines	Underground cables	Number	Nominal capacity (MVA)
220kV	3.0	0	0	0
132kV	2,172	12	82	3,169.50
110kV	21	0	3	300
66kV	7,559	38	420	5,983.58
33kV	5,400	51	1,608	1,733.81
22kV	42,549	380	35,203	2,660.40
11kV and below	70,355	2,442	94,817	7,772.54
SWER (all voltages)	29,644	41	8,683	149.16
Low voltages	25,354	7,102	0	0
Total network	183,057	10,066	140,816	21,768.99

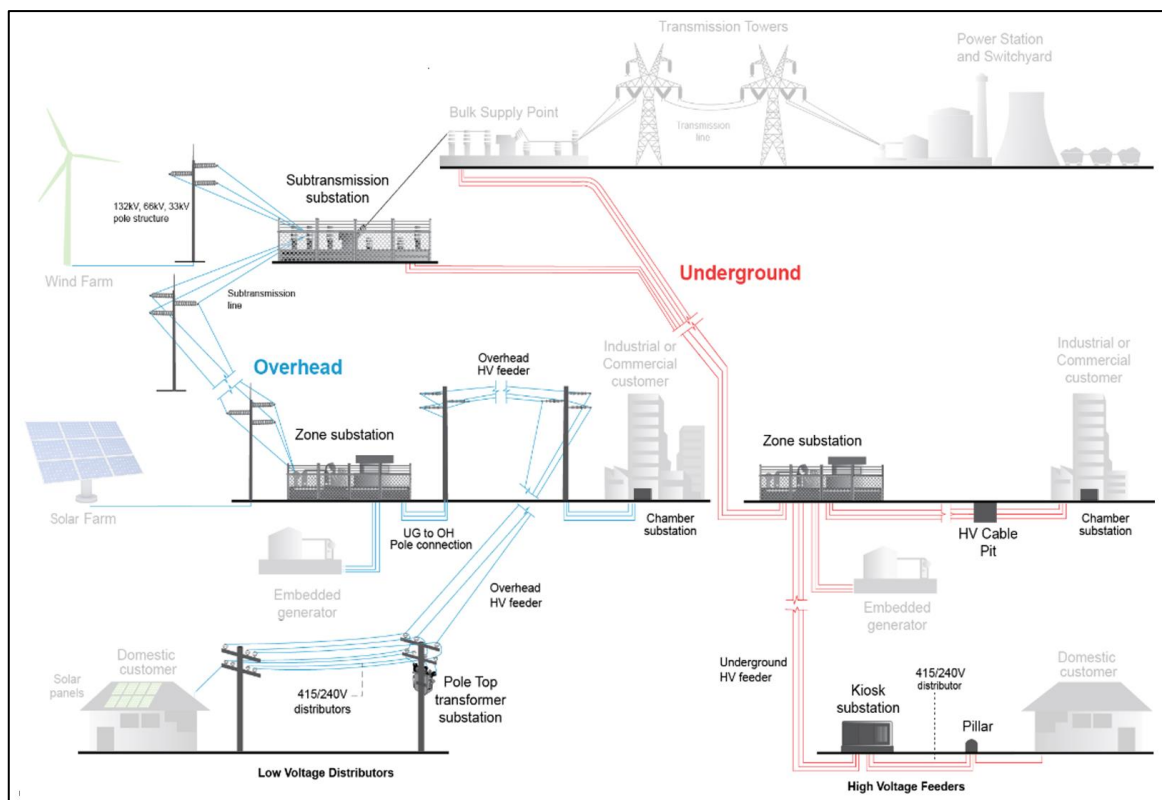


Figure 2 – Typical components of Essential Energy's electricity network

1.3 Annual Planning Review

The NER require that the Annual Planning Review includes the planning for all assets and activities carried out by Essential Energy that would materially affect the performance of its network. This includes planning activities associated with the replacement and refurbishment of assets and negotiated services. The objective of the Annual Planning Review is to identify possible future issues that could adversely impact the performance of the distribution network to enable DNSPs to plan for and adequately address such issues in a timely manner. The outcome of the Annual Planning Review is the DAPR.

This DAPR provides information to Registered Participants and interested parties on the nature and location of emerging constraints on Essential Energy's sub-transmission and high voltage distribution network assets, commonly referred to as the Distribution Network. The timely identification and publication of emerging network constraints allows the market to identify potential non-network solutions and Essential Energy to develop and implement appropriate and timely solutions to them.

The DAPR document is supplemented by three data attachments which can be found on Essential Energy's website <https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/regulatory-reports-and-network-information>

- DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx
- DAPR2022 Limitations Annual Data Essential Energy.xlsx
- DAPR2022 Limitations Load Trace Essential Energy.xlsx

Essential Energy has worked closely with the Institute of Sustainable Futures (ISF) to publish network opportunity maps. These maps use the Australian Renewable Energy Mapping Infrastructure (AREMI) platform to provide a visualisation of emerging constraints over the next 10 years. These maps can be accessed through the AREMI website <https://nationalmap.gov.au/>, under Energy, Electricity Infrastructure, Network Opportunities.

The 2022 DAPR can be visualised through the website <https://dapr.essentialenergy.com.au/>. This site contains an interactive map of the network, including forecasts, limitations, and planned investments.

1.3.1 Network Planning Process

The planning and development process for the distribution network is carried out in accordance with the NER Chapter 5 Part D Planning and Expansion.

Essential Energy carries out network planning at both a strategic and project level. The processes used for each of these levels of network planning are set out in the Essential Energy procedural guideline “*Sub-transmission and Distribution Network Planning Criteria and Guidelines*”, housed and administered through Essential Energy’s Business Management System.

The Essential Energy investment governance process ensures continuous review and assurance that capital prudence and efficiency are being achieved, as well as being consistently aligned with longer term strategic planning as set out within the Essential Energy Corporate Objectives, Strategic Business Plans and Strategic Asset Management Plan (SAMP).

The Essential Energy network planning process uses a quantified approach to monetise the value of risk for Network Constraints and a value-based approach to identify the most effective ways to minimise risk, while delivering benefit to network users.

The first stage of the network planning process involves researching the data required to assess all constraints and assemble a whole-of-network view. This includes historical and existing peak demands, the preparation of a range of seasonal demand forecasts, examining network capacity limits, assessing asset condition and risk of failure, forecasting new customer connections (including new or augmented ‘spot’ loads and/or embedded generators) and taking into account duty of care and regulatory obligations.

The forecast adequacy of the network is assessed against key criteria, including:

- Meeting modern infrastructure standards, including safety and security of the network and environmental compliance
- Addressing any ‘demand – capacity’ imbalance
- Risk, reliability, and power quality performance
- Asset condition and re-investment considerations
- Customer connection requirements (loads and embedded generation).

When emerging network limitations are identified and quantified according to Essential Energy Asset Risk Management and Appraisal Value Frameworks, a range of feasible options, including both network and non-network solutions, are developed to address the network need and to ensure continuing compliance.

All relevant potential credible options, including non-network and operational alternatives are considered in determining how to best meet network performance obligations and the objectives of the NEL.

There is a robust selection process based on analysis of the Net Present Value of options and a range of sensitivity analyses that explicitly trade off alternative investment options. These options use quantified estimates for credible option costs and market benefits against business performance targets to identify the optimum portfolio of projects that minimises the risk and cost of achieving the desired performance.

In accordance with NER obligations and statutory requirements, network augmentation and demand management options are assessed impartially using a consistent value-based review process. Demand management and non-network options are evaluated on the extent to which they can avoid or defer the need for traditional network augmentation.

This DAPR seeks to inform stakeholders and provides advice on emerging network limitations and network adequacy. It also provides details of the expected time required to allow appropriate corrective network augmentation, non-network alternatives or modifications to connection facilities.

The Essential Energy network planning approach is outlined in its Network Management Plan and is consistent with the principles of the NSW Government Total Asset Management framework.

Essential Energy is required to comply with mandatory service standards in accordance with the *Reliability and Performance Licence Conditions for Electricity Distributors (July 2014)* and subsequent variations. This document provides information for locations where investment is required to address network limitations due to forecast demand and other prudent considerations.

1.4 Significant changes from previous DAPR

The 2022 DAPR follows the same format as previous years, with many of the changes being related to network configuration and forecasting methodology improvements. The content has been improved based on feedback from various stakeholders including the AER.

1.4.1 Analysis and explanation of forecast changes

Another mild summer has seen network wide peak demand continue to remain in the winter season. Individual site forecasts continue to show low steady growth on average, though the continued impacts from previous events such as drought, bushfires and the ongoing pandemic have affected some sites where it is unclear what the long-term effects of these events will be.

As site data and the forecasting process is improved, the quality of each forecast is also improving. At all levels from Transmission-Distribution Connection Points to the sub-transmission and zone substation level, forecasts have been adjusted to account for expected load transfers for new and decommissioned sites.

The forecasting process is constantly evolving, particularly as new and / or developing characteristics are identified on the network that impact demand. A summary of the current forecasting methodology is described in further detail in Section 2.2.

1.4.2 Analysis and explanation of changes in other information

The main focus for this document was data quality improvements and adjustments to the forecasting methodology, so the majority of sections within the document contain only minor changes.

2. FORECASTS FOR THE FORWARD PLANNING PERIOD

This section provides a detailed assessment of the current peak demand forecast process.

Peak demand forecasts provide Essential Energy with the basis for identifying network limitations, evaluating the credible network and non-network options to address those limitations and (if applicable) commencing the RIT-D process. It also feeds into the SAMP and identification of the capital and operating investment expected to be required for the forward planning period.

Essential Energy's Network System peak demand for the Summer 2021/22 and Winter 2022 periods peaked in Winter at 2,420 megawatts (MW) at 6:30pm (AEST) on Thursday, 9 June 2022.

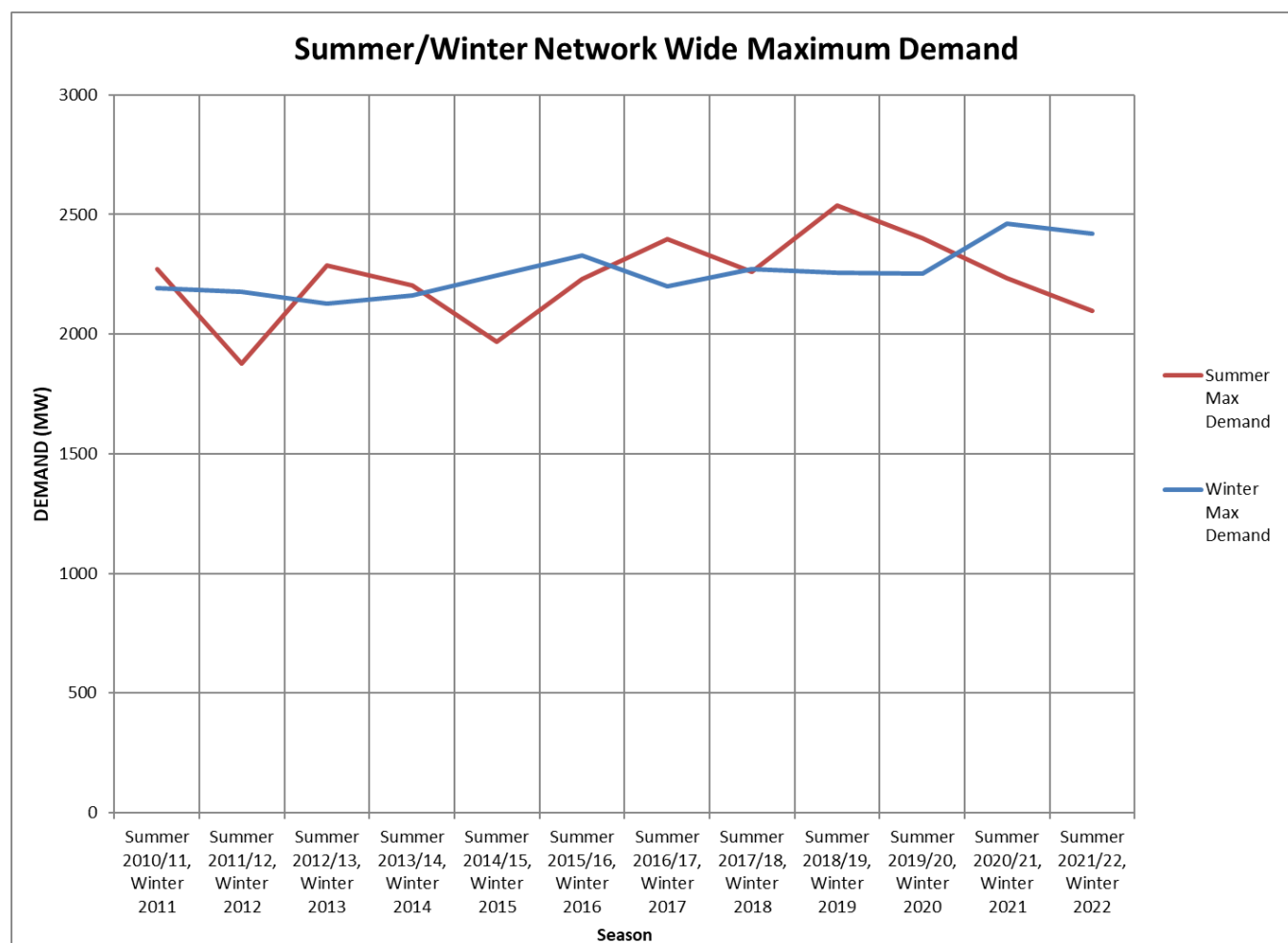


Figure 3 – Essential Energy's recorded maximum demands

2.1 Load Forecasting Strategy

A primary driver in network development and the identification of specific investments is the forecast of electricity demand and energy. The spatial demand forecast is a critical process that supports planning, development of the capital program and the regulatory submission.

Given the importance of the demand forecast on the required capital expenditure and the SAMP, Essential Energy's main objectives are:

- Efficient, closed-loop development and refinement of the forecasting process, data, and documentation
- Engagement of the wider audience to appropriately inform the impacts and building blocks of demand.

In the process of moving towards achieving these objectives, Essential Energy has seen a substantial transition in the network forecasting methodology and process from a relatively simplistic process (such as minimal weather correction and reconciliation between top-down and bottom-up forecasts) which required a high level of subjectivity to a more complex, repeatable process using concepts from the AEMO connection point forecasting methodology.

2.2 Load Forecasting Methodology and Process

The forecasting methodology has been developed and refined using two main vision items as the driving force, these items are:

- That the demand forecasting process undertaken is commensurate with the benefits the forecast provides
- That all demand forecasts are auditable and repeatable.

Essential Energy has developed a methodology which provides for the establishment of the building blocks required to achieve this vision. This methodology is summarised in Figure 4.

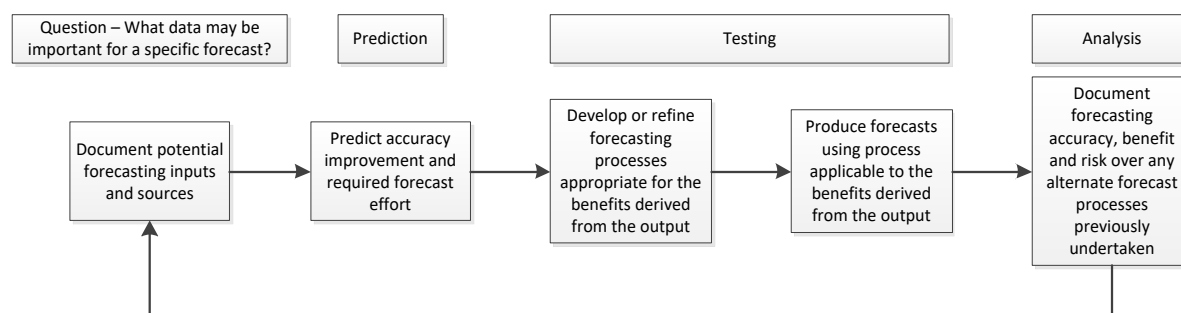


Figure 4 – Forecasting Methodology

As shown in Figure 4, Essential Energy's methodology calls for continuous improvement in the forecasting process specific to the site in question and dependent on the predicted cost/benefit. As an example, some sites may have poor input data and hence poor forecasting accuracy, however if no benefits can be identified from improving the forecast, the cost to improve the process cannot be justified and the forecast inaccuracy specific to the site in question will remain. Alternatively, high benefits (such as capital deferral) would justify substantial forecasting effort and the appropriate level of expense and rigour.

To assist in the network planning process and to identify regional growth patterns, several levels of forecast are used by Essential Energy:

- Overall Essential Energy network forecast
- Regional Transgrid and other TNSP connection point forecasts
- Sub-transmission feeder forecasts
- Zone substation forecasts
- Local distribution feeder forecasts as necessary.

The forecasting process used by Essential Energy is heavily influenced by the Australian Energy Market Operators' (AEMOs) published Connection Point Forecasting Methodology⁴.

⁴ Australian Energy Market Operator – AEMO Connection Point Forecasting Methodology – Forecasting Maximum Electricity Demand in the National Electricity Market 29 July 2016

At a high level, the process consists of:

- **Data collection and collation**

To cater for regional and local needs, a forecast of the demand at each zone substation is developed based on historical demands and information provided by major customers. Account is taken of load diversity between connection points. Embedded generation is recognised and included in the forecast where it offers firm capacity at the time of demand.

- **Outlier removal / Data preparation**

To ensure only system normal conditions are evaluated, short-term network switching, and abnormal metering outputs are removed.

- **Weather correction (or normalisation)**

Historical demand is weather corrected to provide a reference set of conditions from which each year can be compared (with a probability of exceedance of 50 per cent). Daily temperatures and solar irradiance from relevant weather stations covering the last thirty (30) years are used in the correction to account for various forms of demand behaviour.

- **Repeat for each season over the time periods available**

The forecast covers both summer and winter demands and uses data going back up to ten (10) years.

- **Determine the most applicable growth rate based on known variables**

A series of short and long-term trends in the ten years of weather-corrected historical demand is analysed and growth rate selected based on the median of such trends. Where the median does not accurately reflect a sites' growth (e.g., significant changes in historical configuration, customer mix, etc) an alternative growth rate is selected to reflect the current status of the site. In some cases, it may be necessary to remove certain time periods from the analysis where configuration changes have been deemed to significantly impact the trend analysis.

- **Determine starting point of forecasts**

Forecasts generated from weather-corrected and raw history trends, plus results from autoregressive time series models are compared and the most suitable model is chosen as the starting point of each sites' forecast. Where all models generate poor results (e.g. because of small dataset, major configuration changes, etc) then the starting point is taken to be either the most recent historical seasonal maximum demand or overall average maximum demand, whichever is more suitable.

- **Calculate forecast load**

The forecast extends over a planning horizon of ten years, with the first five years published in this report. The forecast power factor used is the median of the forecast power factor distribution derived from the estimated relationship between active and reactive power components.

- **Apply any post model adjustments**

Where there is known potential for the connection of major spot load developments, such as mining loads and major subdivisions, the forecast takes into account any reasonably firm step load increases in the medium term.

- **Reconciliation of forecasts**

Calculations are undertaken to ensure each forecast aligns with upstream and downstream network components, as well as identification of changes to previously developed forecasts.

2.2.1 Sources of load forecast input information

Potential inputs to an individual forecast and the applicable source data may include:

Table 3 – Potential sources of load forecast input information

Potential Inputs	Potential Source Data
Historic demands	Interval meter data, supervisory control and data acquisition (SCADA) data, recloser data, derived loads, assumed factors
Seasonal indicators	Seasonal trends
Future step loads (large customer or residential subdivision)	Information from network planning and major connections
Residential growth rates	Department of Planning
Economic conditions	Australian Bureau of Statistics
Weather patterns	Bureau of Meteorology
Generation	Interval meter data, Bureau of Meteorology, customer information
Individual customer demands	Interval meter data
Regulatory variation	AER documentation, Minimum Energy Performance Standards (MEPS) reports, other government initiatives
Distribution changes	Network information (planning, operations, load control)
Distribution programs	Network program information (planning, load control)
Tariff changes	Network Tariff information
Residential Solar Generation	Solcast estimates from measured solar irradiance
Electric Vehicle Charging	Interval meter data, historic registrations, forecasts of new car sales, connection applications, government incentives / pledges

2.2.2 Assumptions applied to load forecasts

Numerous assumptions are required to streamline the forecasting process. Some of these assumptions are that:

- All large customers and embedded generators are recorded appropriately
- Historic demand data used for summer forecasts comprise the high temperature days from months November to March inclusive while winter forecasts consider the low temperature days from months May to September
- All load information is actual (i.e., no erroneous readings, metering drift, etc)
- All switching events are recorded or easily detected in analysis
- All weather-related data is actual
- The selected weather sites are the best currently available to Essential Energy for representation of the conditions at the load sites
- All historic network changes have been accounted for
- Information provided by large load customers and developers will come to fruition
- Sub-transmission feeder forecasts are a special case, using a proportion of the Bulk Supply point forecast rather than an actual forecast. Hence, sub-transmission forecasts may not reconcile to zone substation forecasts
- Site forecasts are performed individually. Deviations to combined upstream forecasts can easily occur due to individual peak demands occurring at different times.

2.3 Forecast use of Distribution Services by Embedded Generating Units

Forecasts of PV exports are included within the data attachments (DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx). This analysis is in response to an additional section in the NER rules as of this year. An initial method has been established which will be further improved responding to both the learnings of this year and the addition of data as it becomes available. A summary of the methodology is given below:

- Smart meter export data over the last 12 months was collected and summarised to each relevant network site
- Historic yearly installed PV capacity was collected and summarised to each relevant network site
- A logistic growth model was fitted to the historic PV capacity data and forecasts generated based on this model and qualitative assumptions
- For each site, the maximum export value from the smart meter data was calculated
- Each PV capacity forecast yearly growth rate was then multiplied by the corresponding maximum exported value to obtain the PV export forecast

The following assumptions were made to streamline the process:

- The history of installed PV capacity includes areas that have export limits already imposed
- The forecast of PV capacity assumes continual positive growth (no “saturation”), at a reduced rate. This allows for both the natural increase of the ratio of PV to non-PV customers to be realised, while also allowing existing customers to replace older PV systems with larger ones over time.
- Scaling the maximum export value to each PV capacity growth rate was used as some of the energy from the smart meter export data is self-consumed, and the same ratio is assumed to continue in the forecasts
- Sites with large embedded generation connected were included and adjusted accordingly
- Sites with a combined load / export tariff were excluded.

2.4 Supply Areas

The following section contains descriptions and line drawings of Essential Energy’s supply areas. Sub-transmission feeder load and Sub-transmission Substations and Zone Substation load forecasts are available in the data attachment.

2.4.1 Terranora Supply Area

Description of Terranora area

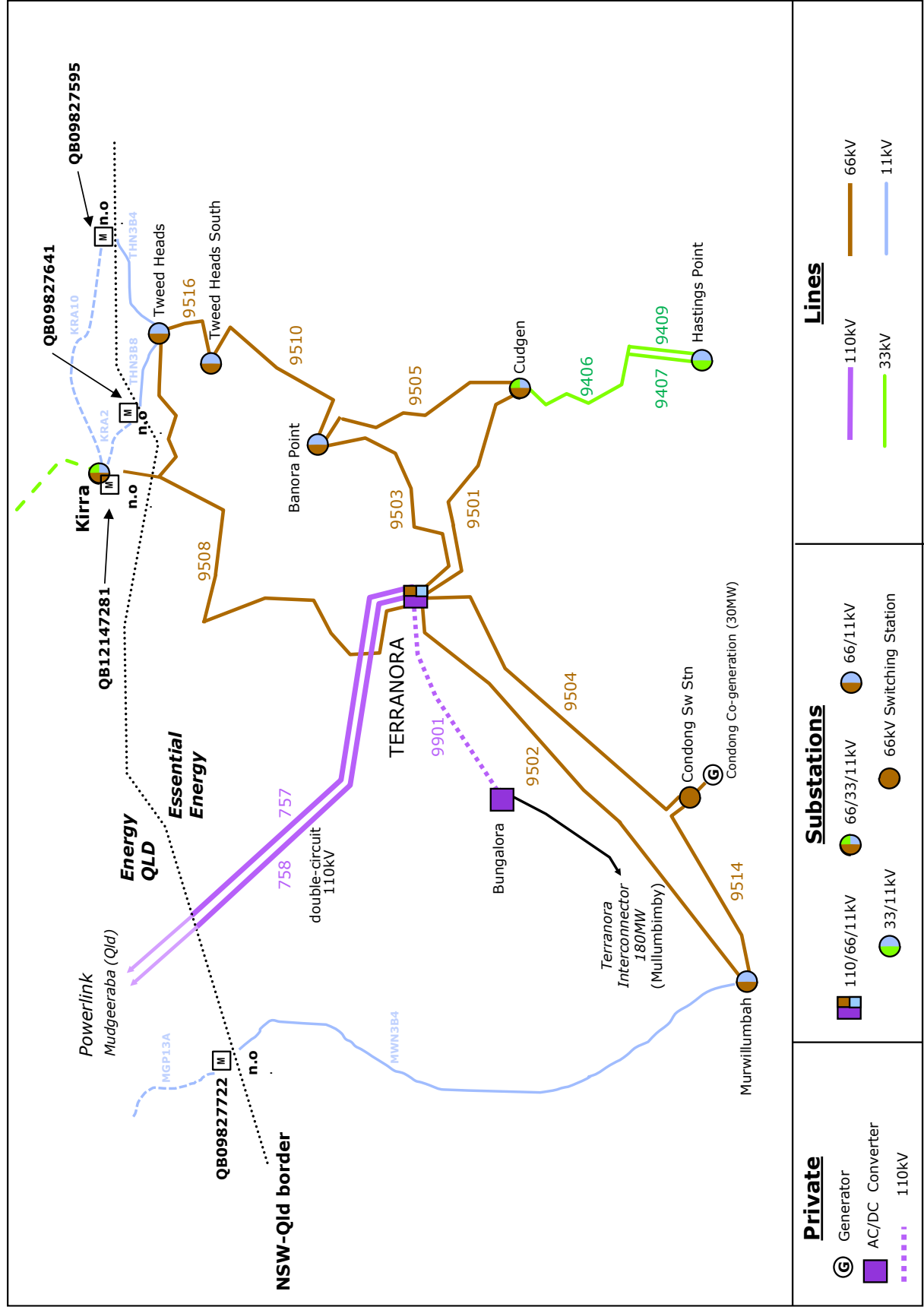
All zone substations in the Terranora area are in the Coastal region.

The Terranora sub-transmission substation is owned by Essential Energy and is supplied from the Queensland transmission system via 2 x 110kV lines that are jointly owned by Essential Energy and Powerlink.

A high voltage direct current transmission network is connected between Mullumbimby and Terranora (via Bungalora) which allows supply to be either injected into the Lismore area from Terranora or injected into the Terranora area from Lismore.

A 30MW biomass generator is located at Condong and is connected to the Terranora 110/66kV sub-transmission substation at 66kV via feeders 9504, 9514 and 9502.

Sub-transmission Single Line Diagram of Terranora area



2.4.2 Lismore Supply Area

Description of Lismore area

Zone substations in the Lismore area are spread across both the Coastal and Ranges regions.

The Lismore 132/66kV sub-transmission substation is owned by Essential Energy. It receives its supply via three Essential Energy 132kV lines from the Transgrid 330/132kV sub-transmission substation at Lismore.

A high voltage direct current transmission network is connected between Mullumbimby and Terranora (via Bungalora) which allows supply to be either injected into the Lismore area from Terranora or injected into the Terranora area from Lismore.

A 30MW biomass generator is located at Broadwater and is connected to the Lismore 132/66kV sub-transmission substation at 66kV via feeder 0892.

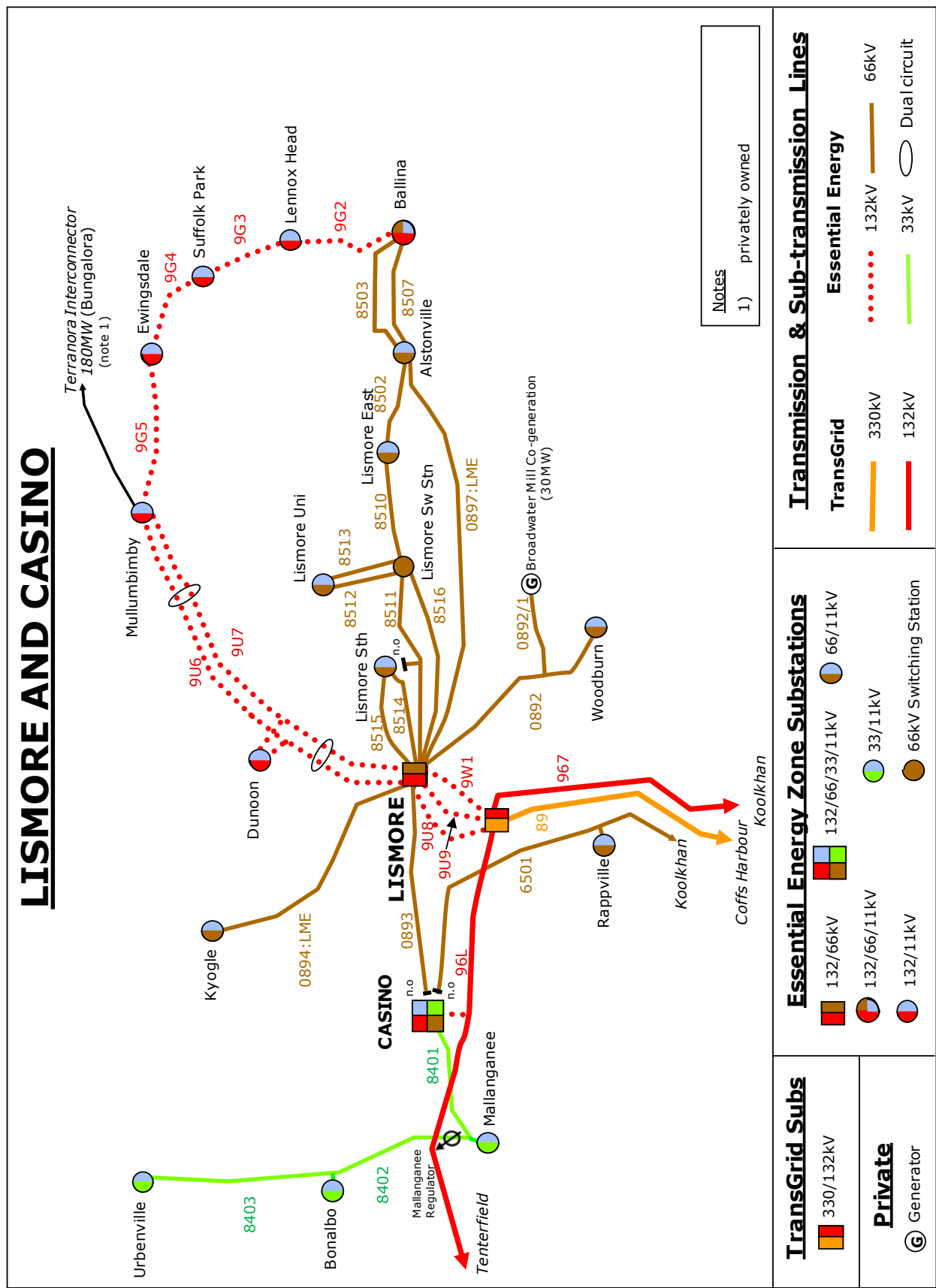
2.4.3 Casino Supply Area

Description of Casino area

All zone substations in the Casino area are in the Ranges region.

The Casino area sub-transmission system is supplied from the Essential Energy 132/66kV sub-transmission substation at Casino which is teed off the Transgrid 132kV Tenterfield to Lismore line. On loss of the single 132/66kV transformer, 66kV supply reverts to Lismore 132/66kV substation via the Lismore – Casino 66kV line (0893).

Sub-transmission Single Line Diagram of Lismore area

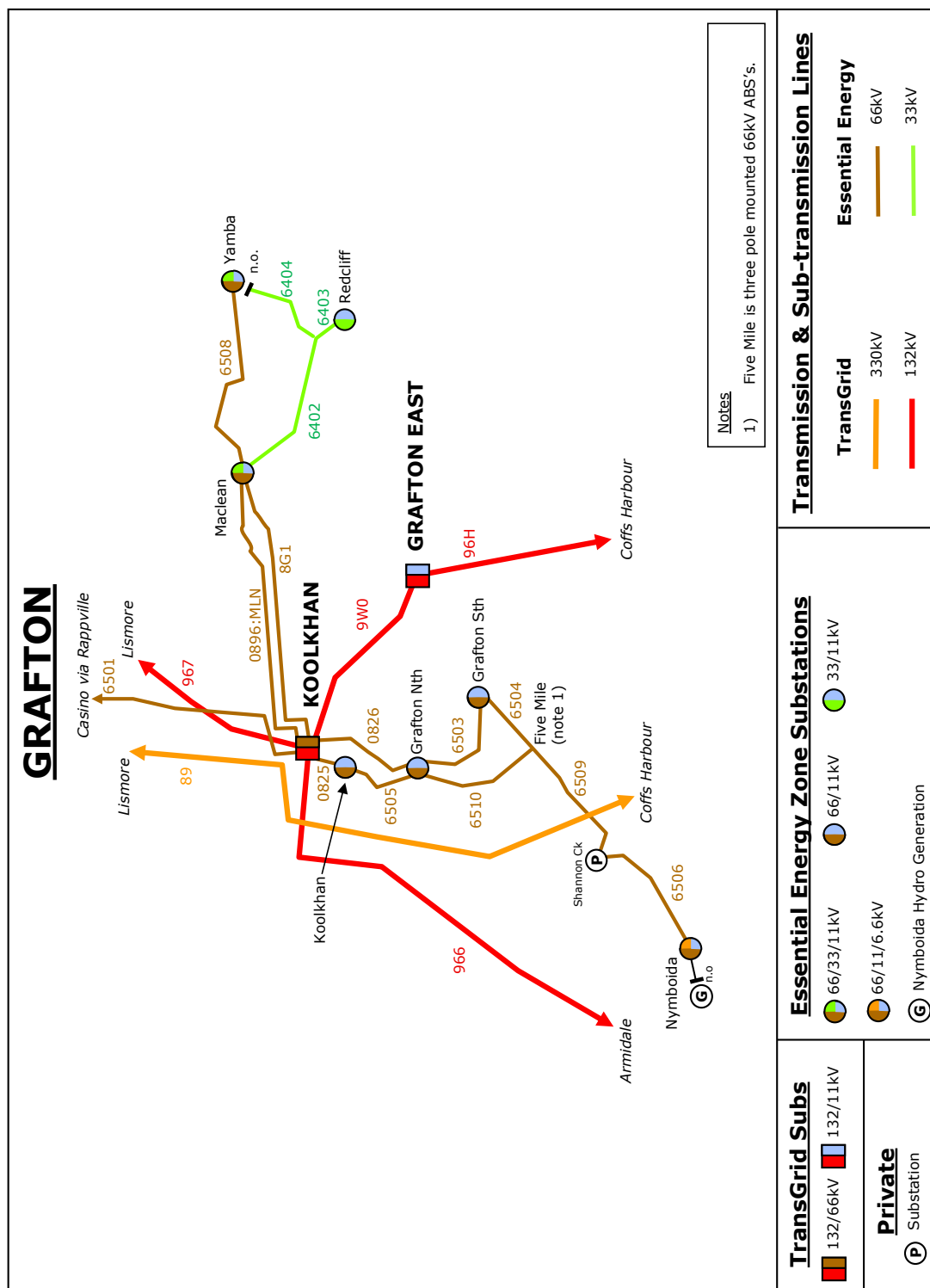


2.4.4 Grafton Supply Area

Description of Grafton area

All zone substations in the Grafton area are in the Coastal region. The Grafton area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Koolkhan.

Sub-transmission Single Line Diagram of Grafton area



2.4.5 Coffs Harbour Supply Area

Description of Coffs Harbour area

All zone substations in the Coffs Harbour area are in the Mid North Coast region.

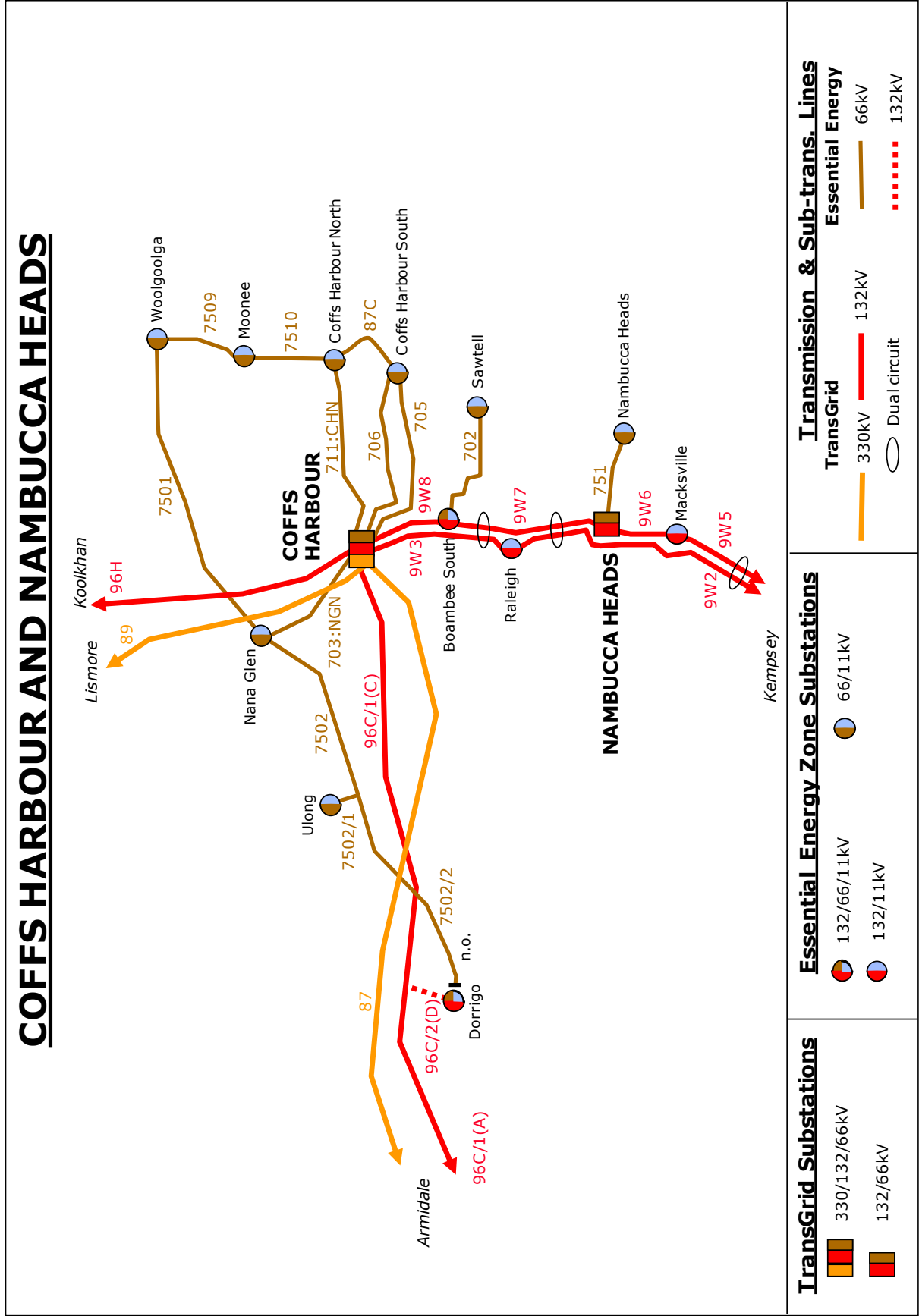
The Coffs Harbour area sub-transmission system is supplied from the Transgrid 330/132/66kV sub-transmission substation at Coffs Harbour (Karangi). The Dorrigo substation is normally connected via the Essential Energy 132kV tee line from the Transgrid 132kV transmission line between Armidale and Coffs Harbour with back up from the 66kV system. Boambee South is an Essential Energy 132/66/11kV zone substation that is supplied by the Transgrid 132kV transmission network between Kempsey and Coffs Harbour.

2.4.6 Nambucca Heads Supply Area

Description of Nambucca Heads area

All zone substations in the Nambucca Heads area are in the Mid North Coast region.

The Nambucca Heads area sub-transmission system is supplied from the Transgrid 132kV transmission network. Nambucca Heads is a 66/11kV zone substation supplied via a 66kV line from Transgrid's Nambucca 132/66kV substation, while Raleigh and Macksville are 132/11kV zone substations supplied from the Transgrid 132kV transmission network between Kempsey and Coffs Harbour.

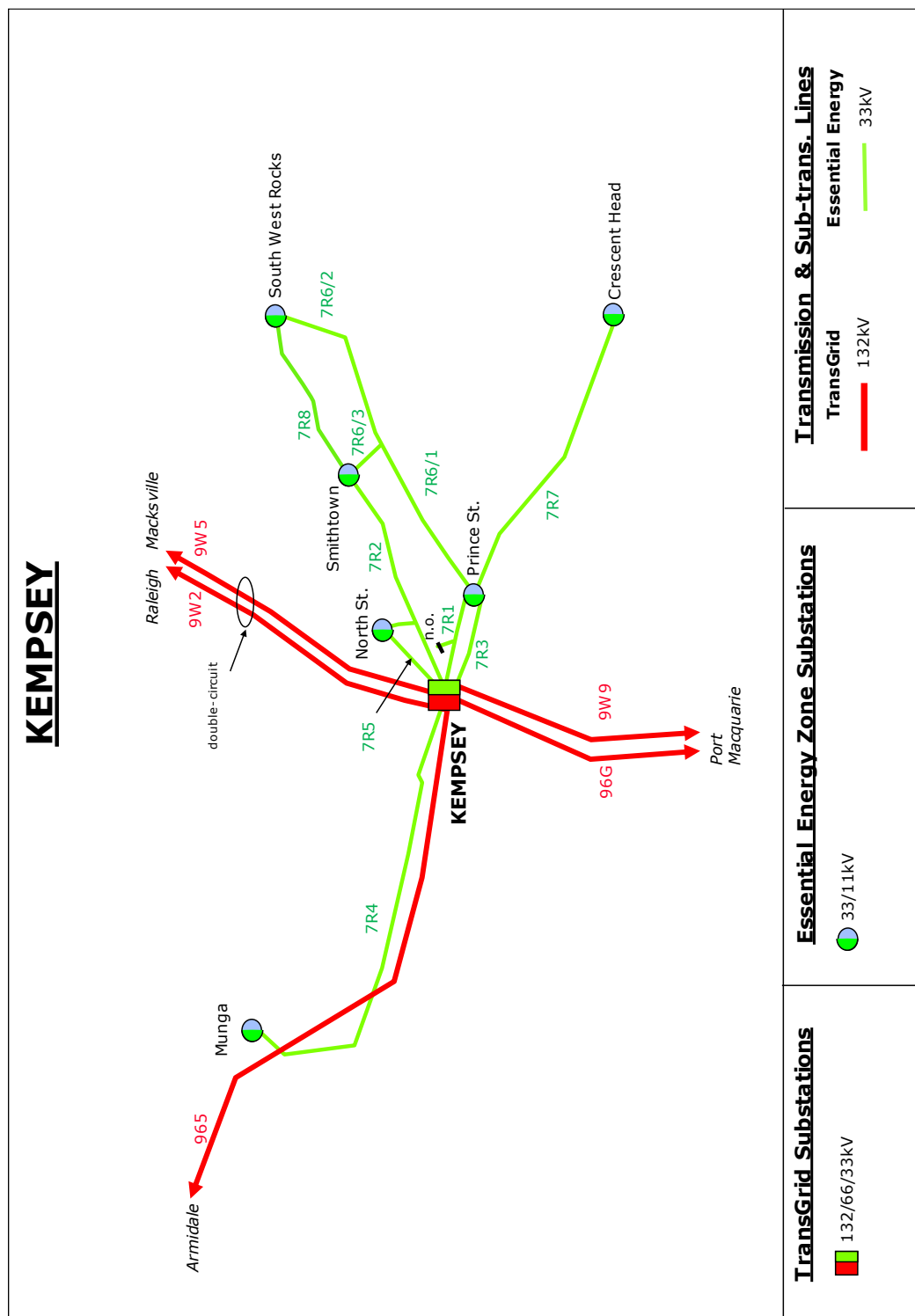


2.4.7 Kempsey Supply Area

Description of Kempsey area

All zone substations in the Kempsey area are in the Mid North Coast region. The Kempsey area sub-transmission system is supplied from the Transgrid 132/33kV sub-transmission substation at Kempsey.

Sub-transmission Single Line Diagram of Kempsey area

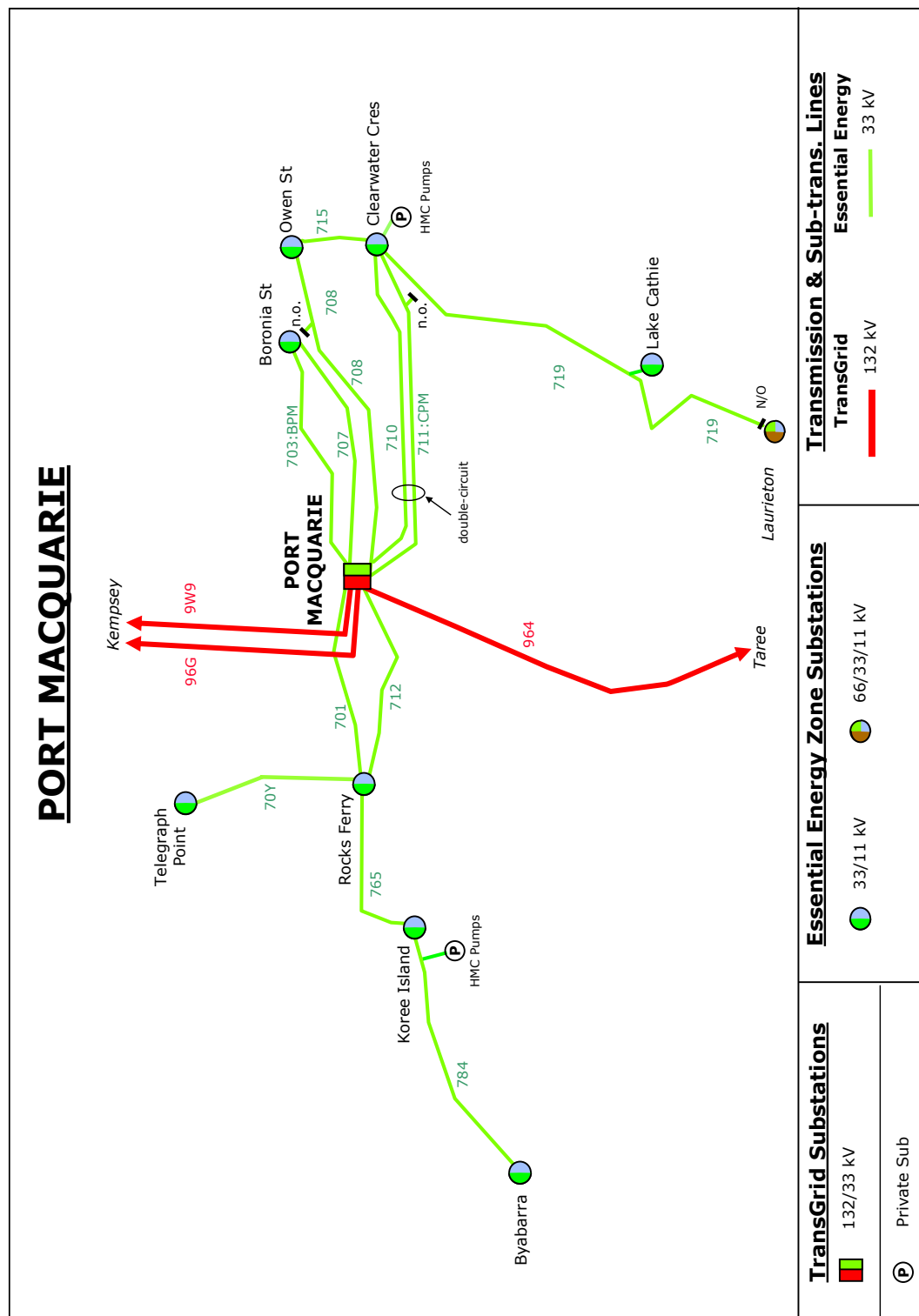


2.4.8 Port Macquarie Supply Area

Description of Port Macquarie area

All zone substations in the Port Macquarie area are in the Mid North Coast region. The Port Macquarie area sub-transmission system is supplied from the Transgrid 132/33kV sub-transmission substation at Port Macquarie.

Sub-transmission Single Line Diagram of Port Macquarie area



2.4.9 Herons Creek Supply Area

Description of Herons Creek area

All zone substations in the Herons Creek area are in the Mid North Coast region.

The Herons Creek 132/66kV substation is owned by Essential Energy. It receives supply via a tee off Transgrid's Taree – Port Macquarie 132kV line (#964). Johns River, Kew and Laurieton 66/11kV zone substations take normal 66kV supply from Herons Creek, and backup 66kV supply from Transgrid's Taree 132/66/33kV substation via the Essential Energy 66kV line (#862).

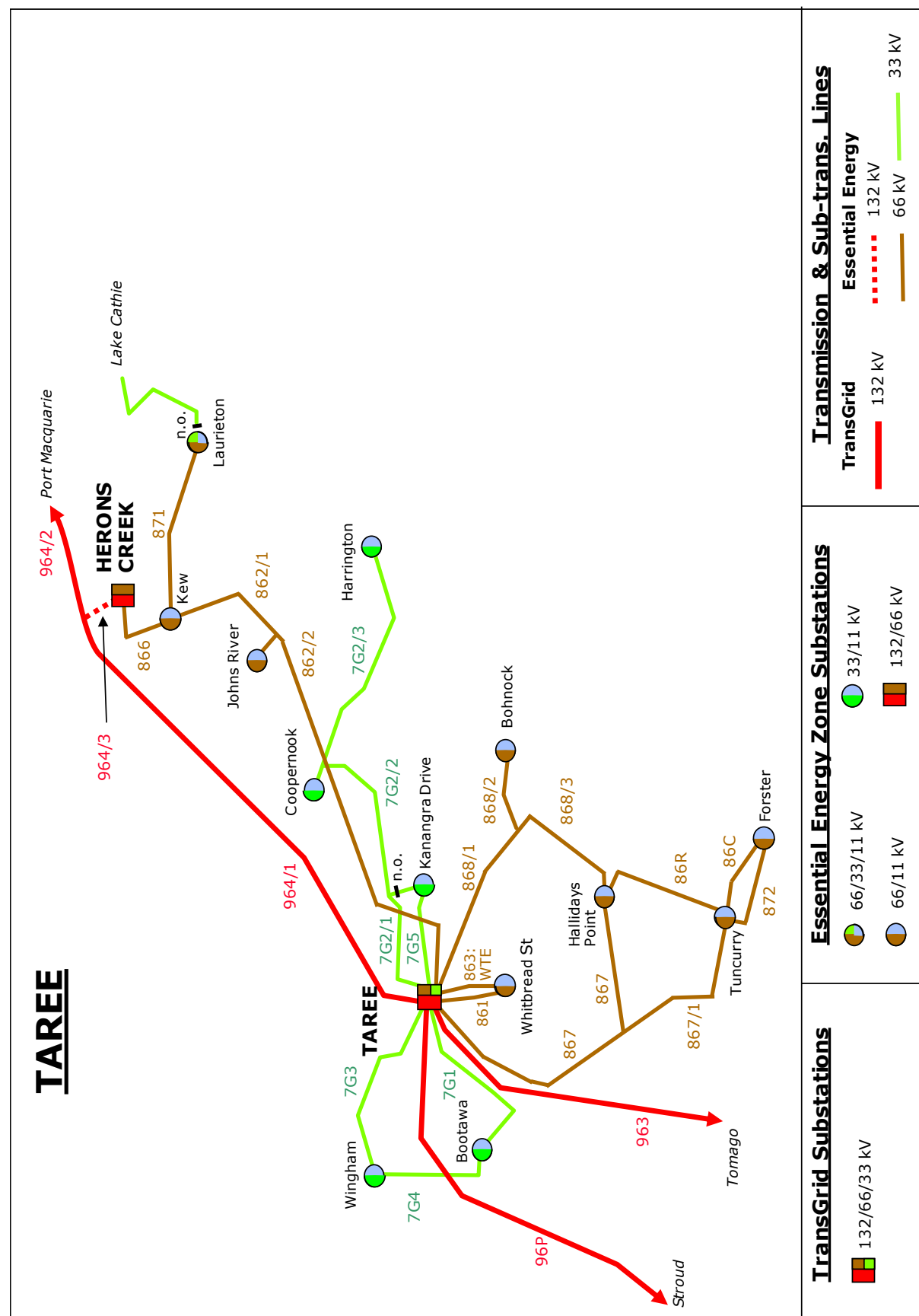
2.4.10 Taree Supply Area

Description of Taree area

All zone substations in the Taree area are in the Mid North Coast region.

The Taree area sub-transmission system is supplied from the Transgrid 132/66/33kV sub-transmission substation at Taree.

Sub-transmission Single Line Diagram of Taree area



2.4.11 Stroud Supply Area

Description of Stroud area

All zone substations in the Stroud area are in the Mid North Coast region.

The Stroud 132/33kV sub-transmission substation is owned by Essential Energy. It receives supply via two Transgrid 132kV lines. sub-transmission supply to Martins Creek and Gresford is taken from Stroud, with a secondary supply that emanates from Ausgrid's Network. The 33kV sub-transmission line is partly owned by Essential Energy.

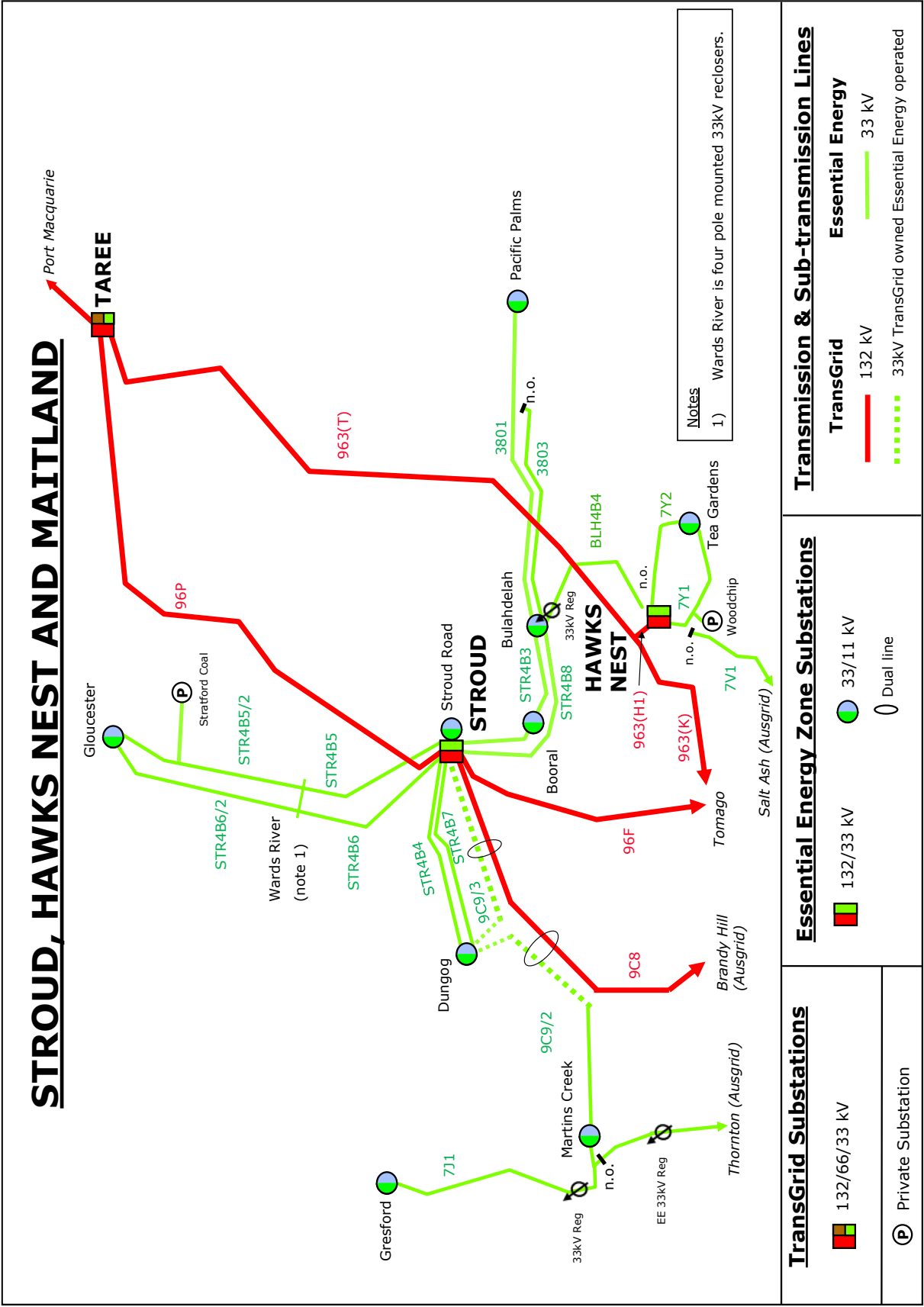
2.4.12 Hawks Nest Supply Area

Description of Hawks Nest area

All zone substations in the Hawks Nest area are in the Mid North Coast region.

The Hawks Nest 132/33kV sub-transmission substation is owned by Essential Energy. It receives supply via a tee off the Transgrid Tomago to Taree 132kV line (#963). Tea Gardens zone substation takes normal supply from the Hawks Nest 132/33kV substation. Tea Gardens zone substation takes backup supply from a 33kV sub-transmission line that emanates from Ausgrid's Tomago network. A partial backup supply for Tea Gardens is via the 33kV network emanating from the Stroud substation via Bulahdelah.

Sub-transmission Single Line Diagram of Stroud area



2.4.13 Armidale Supply Area

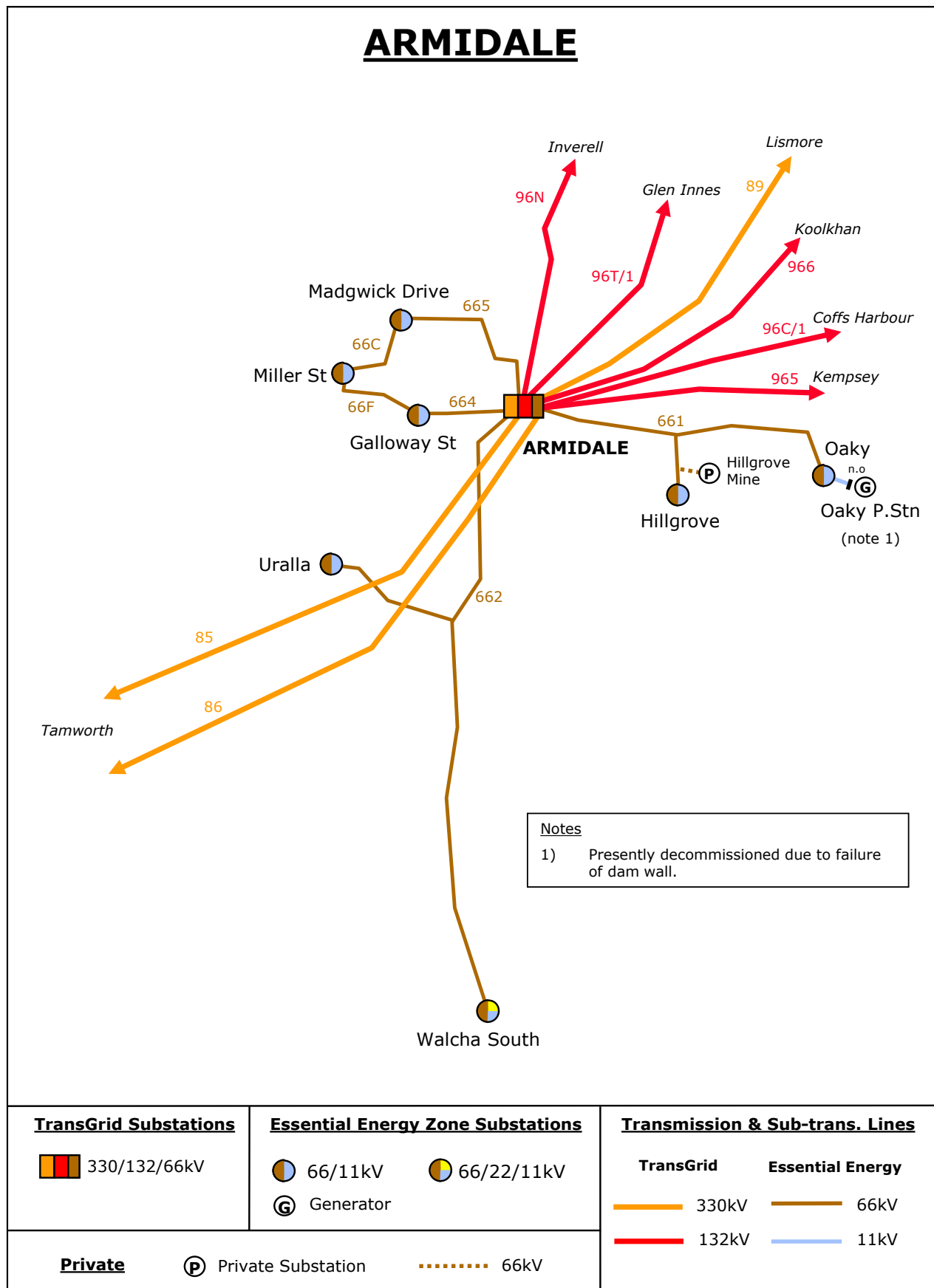
Description of Armidale area

Zone substations in the Armidale area are spread across both the Ranges and Northern Tablelands regions.

The Armidale area sub-transmission system is supplied from the Transgrid 330/132/66kV sub-transmission substation at Armidale.

The 5MW hydro generation at Oaky is presently decommissioned after failure of the dam wall.

Sub-transmission Single Line Diagram of Armidale area



2.4.14 Glen Innes Supply Area

Description of Glen Innes area

Zone substations in the Glen Innes area are spread across both the Ranges and Northern Tablelands regions.

The Glen Innes area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Glen Innes.

A 5.5MW hydro generator is located at Pindari Dam and is connected to the Transgrid Glen Innes 132/66kV sub-transmission substation at 66kV via feeders 6AE, 6NE, 886 and 887.

2.4.15 Tenterfield Supply Area

Description of Tenterfield area

All zone substations in the Tenterfield area are in the Ranges region.

The Tenterfield area is supplied at 22kV and 11kV from the Transgrid 132/22/11kV sub-transmission substation at Tenterfield. Essential Energy is responsible for the 22/11kV substation area.

2.4.16 Waggamba (Ergon) Supply Area

Description of Waggamba area

All zone substations in the Waggamba area are in the Northern Tablelands region.

The Waggamba area sub-transmission system is supplied from the Ergon 132/66/33kV sub-transmission substation at Goondiwindi. The 132/66/33kV substation is supplied by a 132kV network from Powerlink's Bulli Creek substation.

Backup supply to Goondiwindi is limited to a maximum of 20MVA via 66kV from Inverell.

2.4.17 Inverell Supply Area

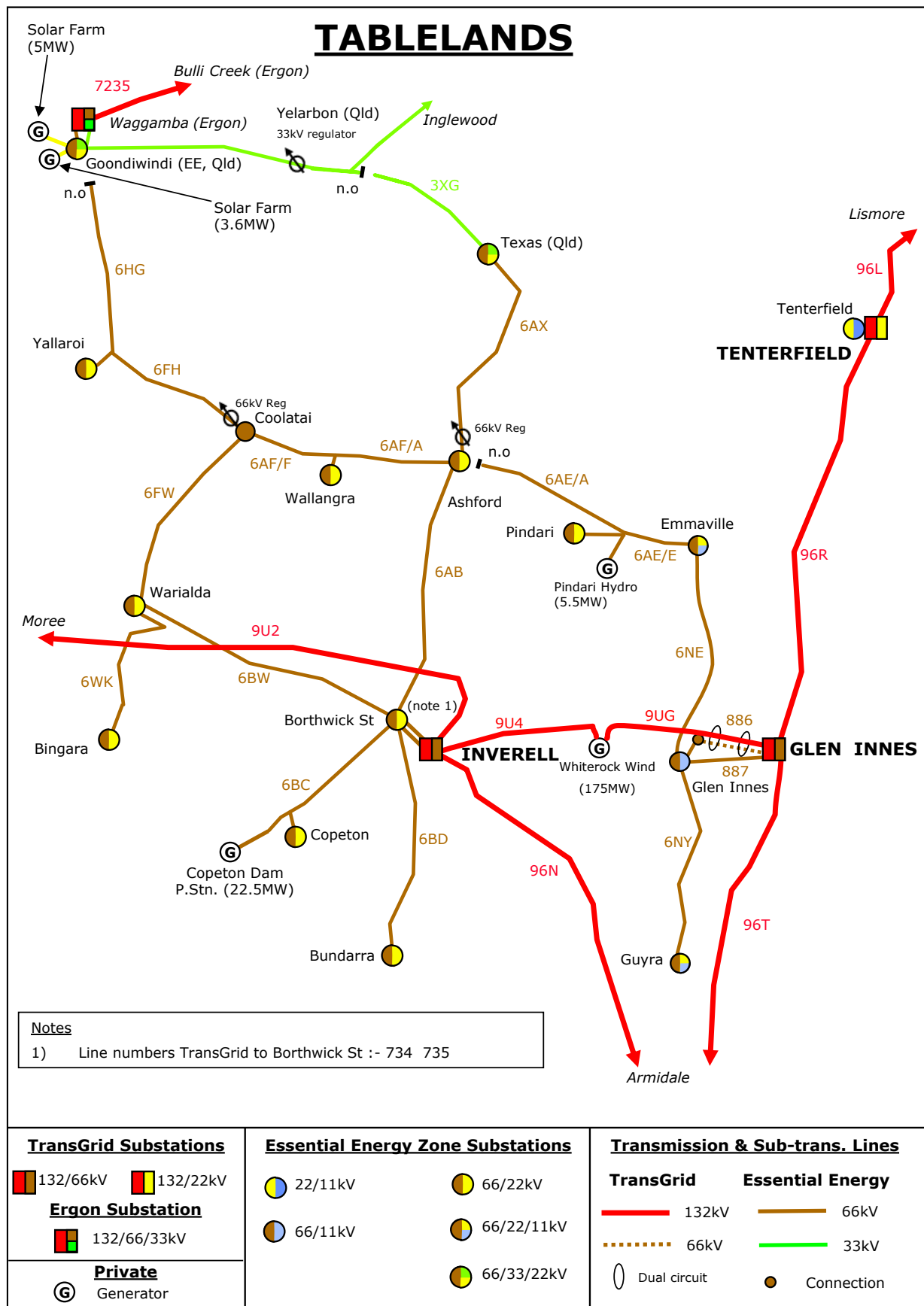
Description of Inverell area

All zone substations in the Inverell area are in the Northern Tablelands region.

The Inverell area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Inverell.

A 23MW hydro generator is located at Copeton Dam and is connected to the Transgrid Inverell 132/66kV sub-transmission substation at 66kV via feeders 6BC, 734 and 735.

Sub-transmission Single Line Diagram of Glen Innes area



2.4.18 Moree Supply Area

Description of Moree area

All zone substations in the Moree area are in the Northern Tablelands region.

The Moree area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Moree.

A 56MW solar generator is located at Moree Solar Farm and is connected to Transgrid's Moree 132/66kV sub-transmission substation at 66kV via feeder 876.

A 5MW solar generator is located at Wenna on the 22kV network.

2.4.19 Narrabri Supply Area

Description of Narrabri area

Zone substations in the Narrabri area are spread across both the Northern Tablelands and North Western regions.

The Narrabri area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Narrabri.

A 10MW and 6MW gas generator located at Wilga Park is connected to the Transgrid Narrabri 132/66kV sub-transmission substation at 66kV via feeder 861.

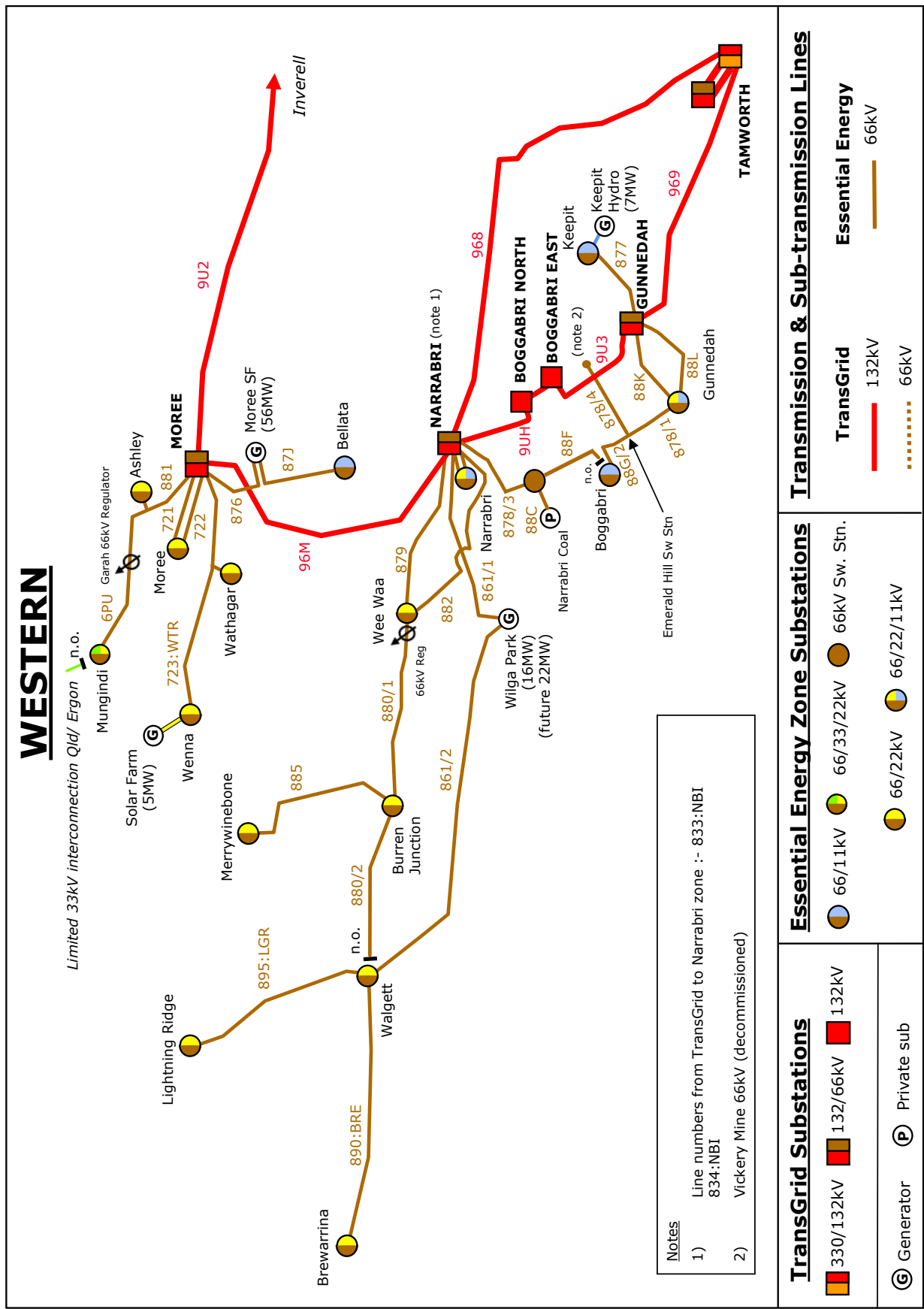
2.4.20 Gunnedah Supply Area

Description of Gunnedah area

All zone substations in the Gunnedah area are in the Northern Tablelands region.

The Gunnedah area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Gunnedah.

A 7MW hydro generator is located at Lake Keepit and is connected to the Transgrid Gunnedah 132/66kV sub-transmission substation at 66kV via feeder 877.

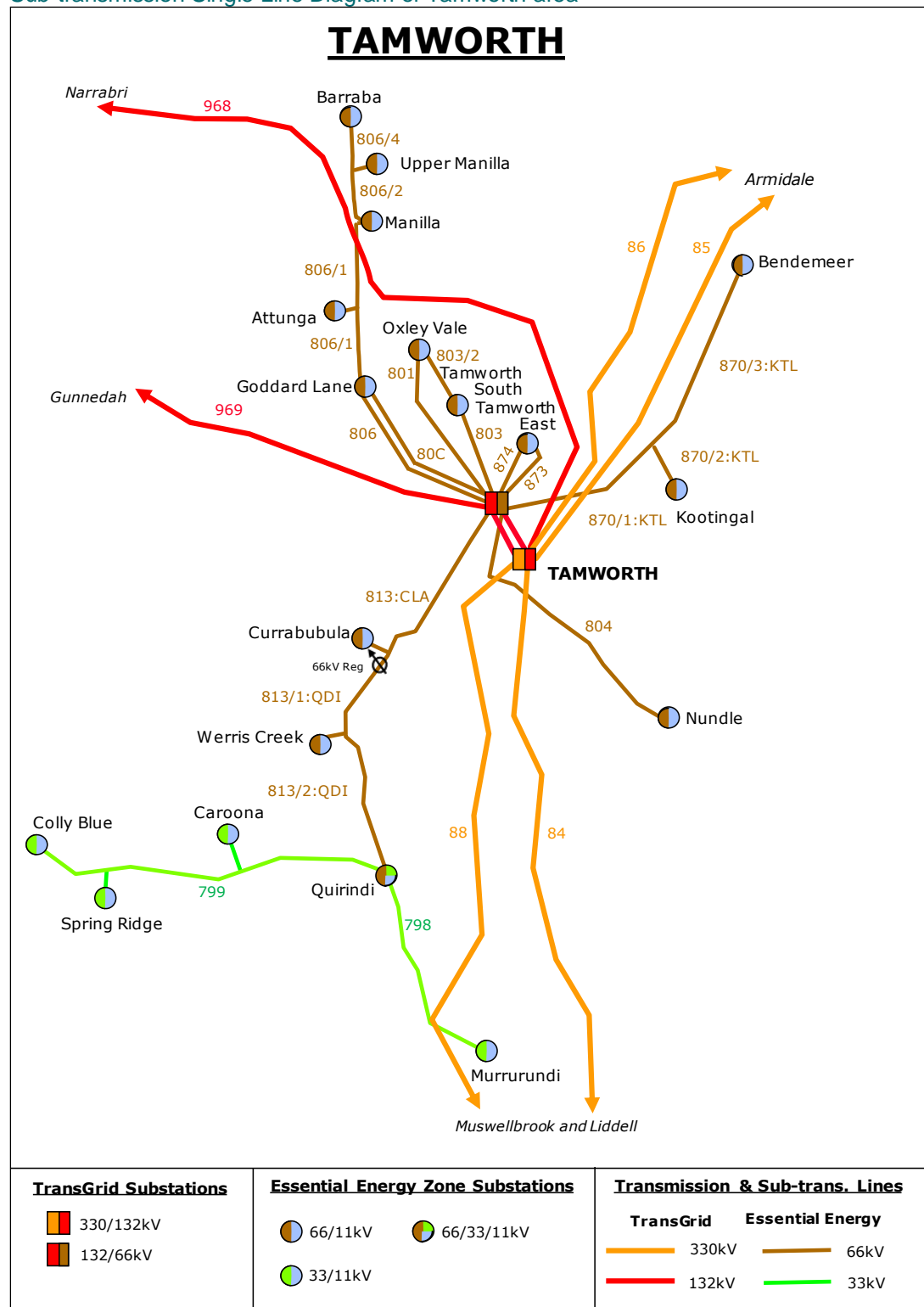


2.4.21 Tamworth Supply Area

Description of Tamworth area

All zone substations in the Tamworth area are in the Northern Tablelands region. The Tamworth area sub-transmission system is supplied from the Transgrid 132/66kV sub-transmission substation at Tamworth.

Sub-transmission Single Line Diagram of Tamworth area



2.4.22 Beryl Supply Area

Description of Beryl area

Zone substations in the Beryl area are spread across both the Northern Tablelands and Macquarie regions.

The Beryl area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation. The Mudgee substation is normally connected to the Essential Energy 132kV teed line from the Transgrid Mt Piper to Beryl 132kV transmission line with back up from the Beryl 66kV system via Gulgong.

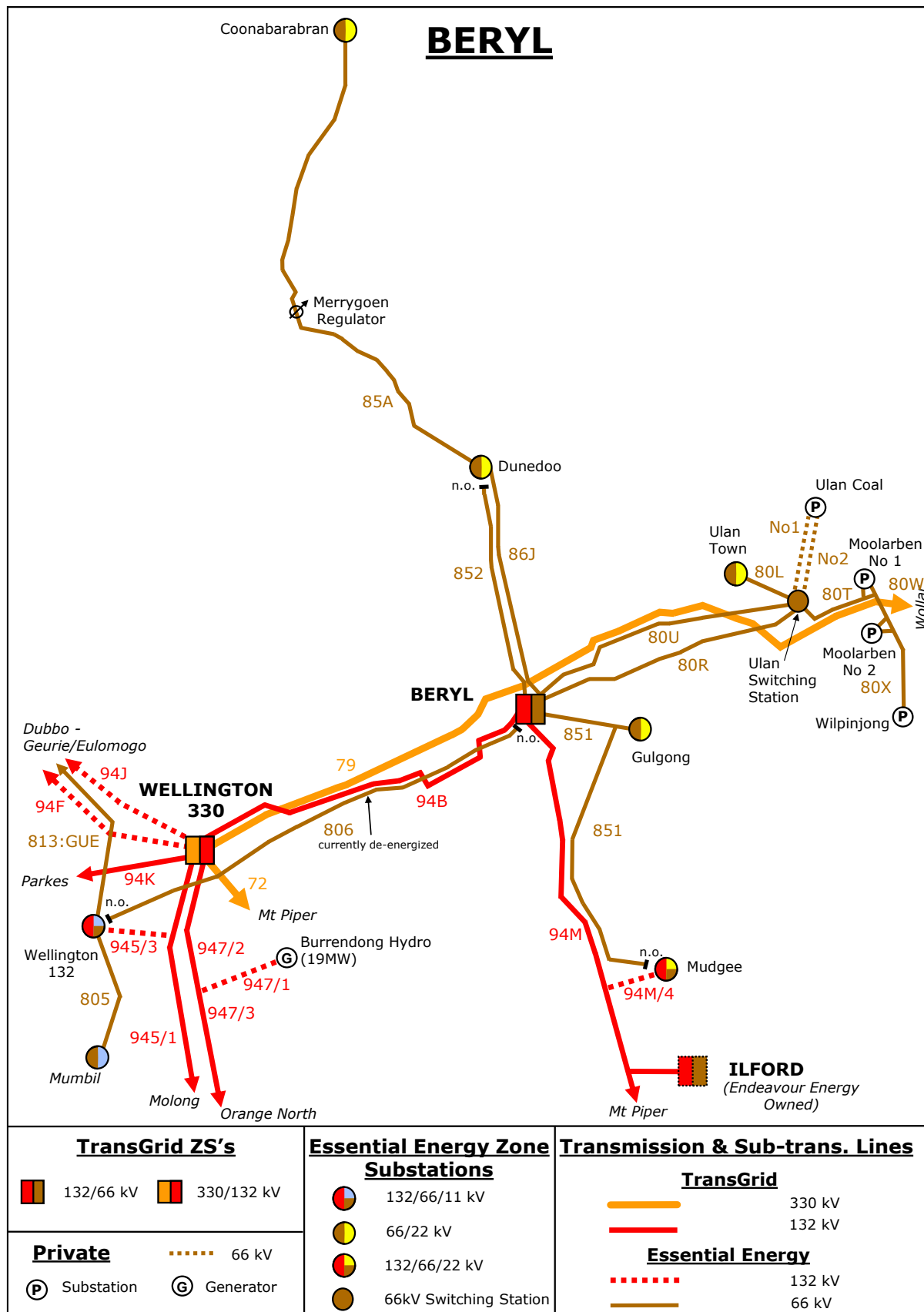
2.4.23 Wellington Supply Area

Description of Wellington area

All zone substations in the Wellington area are in the Macquarie region.

The Essential Energy Wellington 132/66/11kV zone substation is normally connected to the Essential Energy 132kV tee line #945/3 from Transgrid's Wellington to Molong 132kV transmission line #945. The 66kV supply for Mumbil is obtained from the Wellington 11kV busbar via a step up 66/11kV transformer. The backup supply for Wellington and Mumbil is via the 66kV powerline #813 from Eulomogo.

Sub-transmission Single Line Diagram of Beryl area



2.4.24 Dubbo Supply Area

Description of Dubbo area

Zone substations in the Dubbo area are spread across both the Macquarie and North Western regions.

Essential Energy owns two 132kV powerlines emanating from the Transgrid owned Wellington 330/132kV sub-transmission substation that support the Dubbo 132/66kV sub-transmission substation and Nyngan 132/66kV sub-transmission substation supply areas.

The Narromine zone substation is supplied from the Narromine South Switching station connected between Dubbo South and Nyngan 132kV.

The Nevertire zone substation is normally supplied from the 132kV network via a tee, off the 94W Dubbo to Nyngan 132kV line, with back up supply available from Nyngan 66kV system via Nyngan Town.

A 9.2MW solar generator is located at Narromine on the 22kV network, and a 14.5MW solar generator is connected at Dubbo South on the 11kV network.

A 105MW solar generator is located at Nevertire and is connected to the Dubbo 132/66kV sub-transmission substation at 132kV via the feeder 94W.

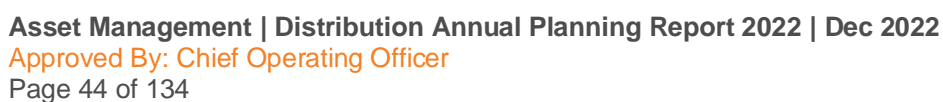
2.4.25 Nyngan Supply Area

Description of Nyngan area

All zone substations in the Nyngan area are in the North Western region.

Essential Energy's Nyngan 132/66kV substation is supplied from our Dubbo 132/66kV sub-transmission substation via two Essential Energy 132kV transmission lines. The 94W Dubbo to Nyngan 132kV line has a tee connection into Nevertire, with back up supply available from Nyngan 66kV system via Nyngan Town and the 94J-9GU Dubbo to Nyngan 132kV line via Narromine South switching station.

A 102MW solar generator is located at Nyngan Solar Farm and is connected to the Nyngan 132/66kV sub-transmission substation at 132kV via the feeder 9UT.



2.4.26 Broken Hill Supply Area

Description of Broken Hill area

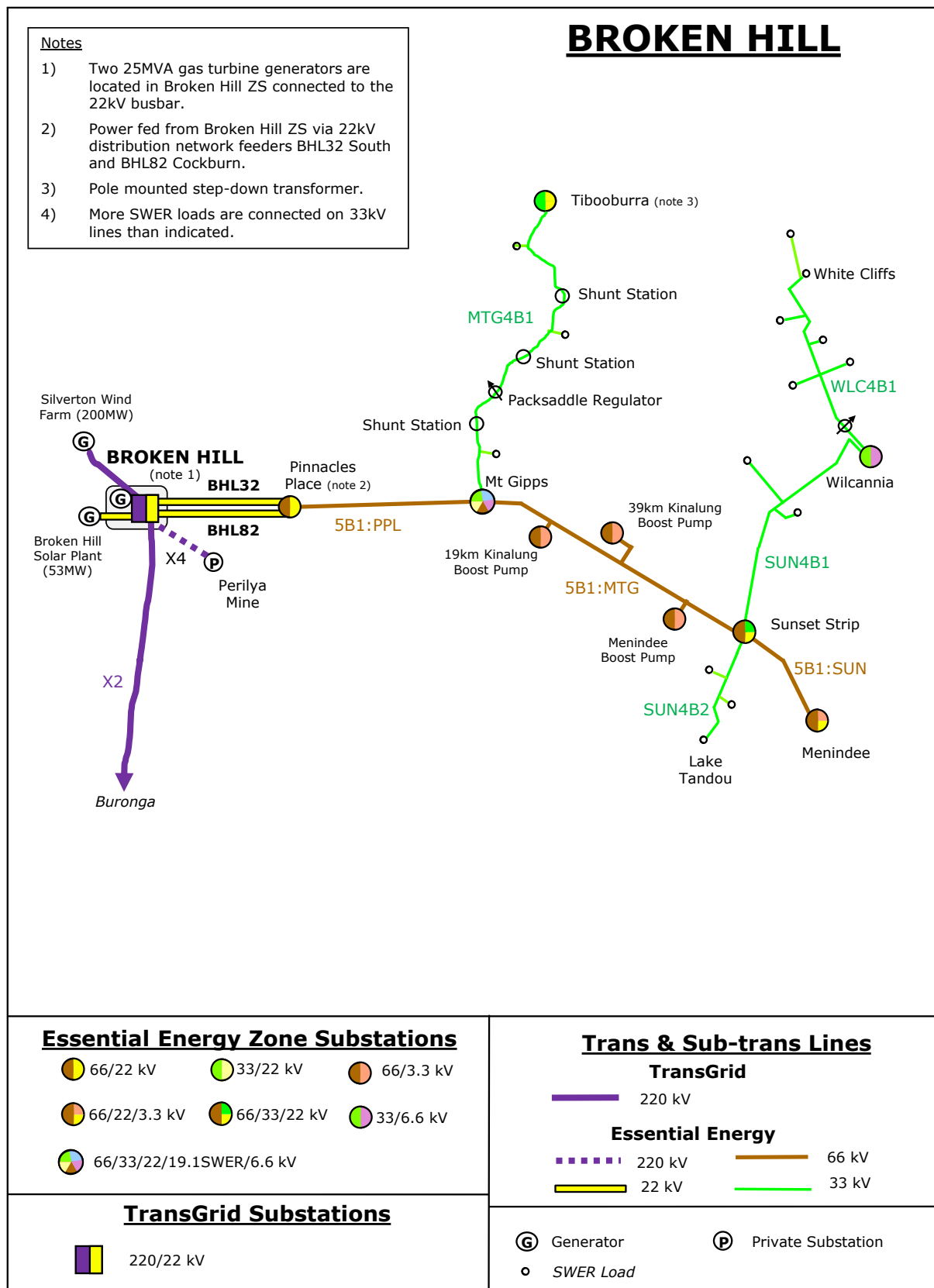
All zone substations in the Broken Hill area are in the North Western region.

The Broken Hill area is supplied from Transgrid's 220/22kV substation. Essential Energy utilises two 22kV lines and steps them up to 66kV for supply to Mt Gipps and Sunset Strip from which 33kV and other voltage levels are derived for specific purposes.

A 53MW solar generator is located at Broken Hill and is connected to the Transgrid Broken Hill 220/22kV sub-transmission substation at 22kV.

There have been changes to the water pump network with a new water supply now coming from Wentworth. It is unclear what the long-term configuration will be for the existing water pump infrastructure and whether it will affect peak loads.

Sub-transmission Single Line Diagram of Broken Hill area



2.4.27 Orange Supply Area

Description of Orange area

All zone substations in the Orange area are in the Macquarie region.

The Orange area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation, with the Orange town substations (Industrial, North, South and West) being supplied via a 66kV ring network. The Orange area provides a back-up 66kV supply to Molong via Orange West which supplies Cumnock and Molong via a 66/11kV transformer.

2.4.28 Molong Supply Area

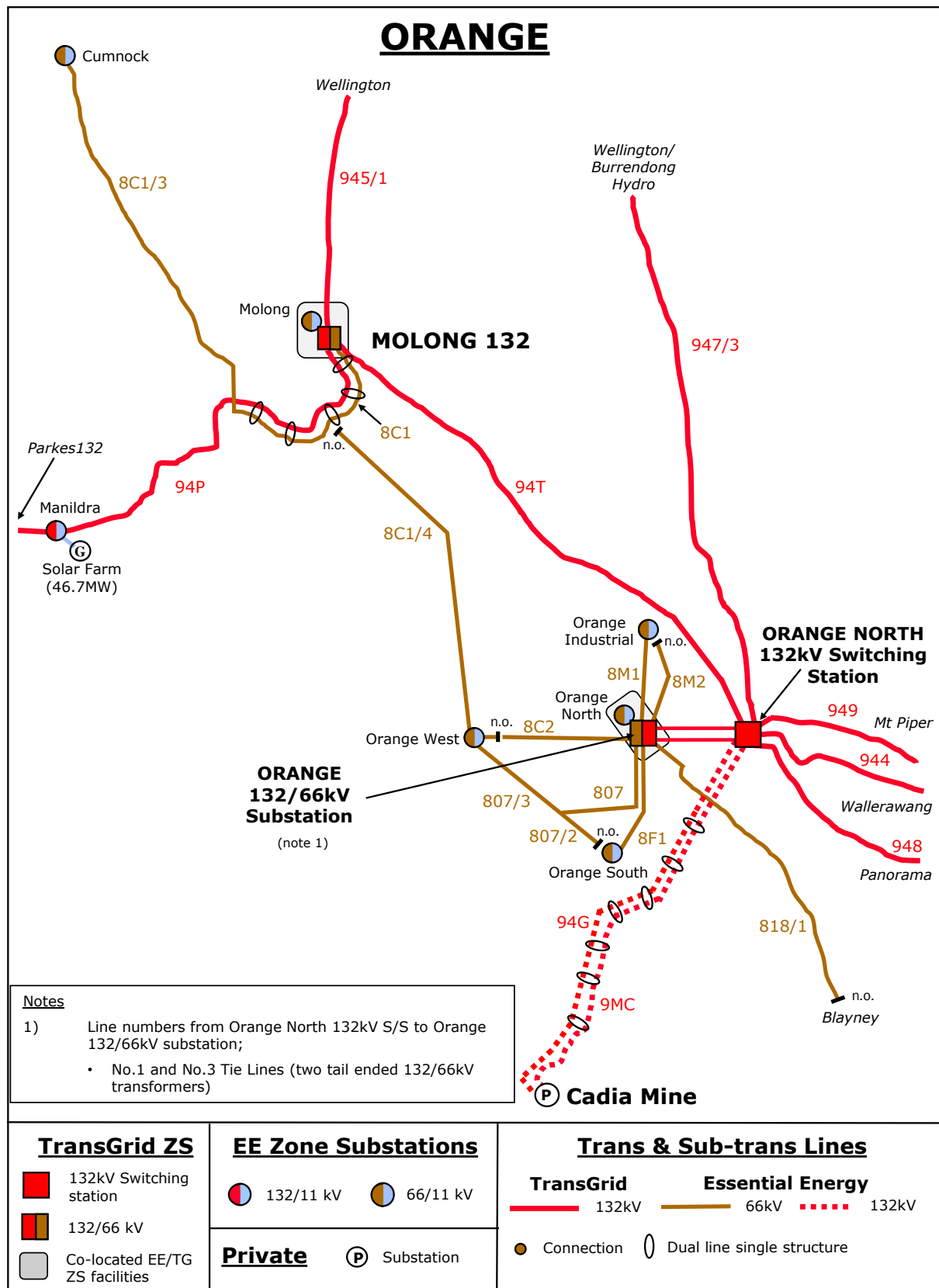
Description of Molong area

All zone substations in the Molong area are in the Macquarie region.

The Molong 132/66/11kV substation is a shared asset with Transgrid, whereby Essential Energy takes supply at 66kV which supplies Cumnock and Molong via a 66/11kV transformer, with back up supply from the Orange 66kV network via Orange West. Manildra zone substation is also a shared asset with Transgrid and is supplied from Transgrid's Molong substation at 132kV.

A 46.7MW solar generator is located at Manildra on the 11kV network.

Sub-transmission Single Line Diagram of Orange area



2.4.29 Bathurst Supply Area

Description of Bathurst area

All zone substations in the Bathurst area are in the Macquarie region.

The Bathurst area sub-transmission system is supplied from Transgrid's Panorama 132/66kV sub-transmission substation with the Bathurst town substations (Russell St, Raglan and Stewart) being supplied via 66kV ring network.

The Blayney and Mandurama substations are supplied by a radial 66kV line from Panorama with a 66kV back up supply from Orange if required.

A 10MW wind generator is located at Blayney wind farm and is connected to the Transgrid Panorama 132/66kV sub-transmission substation at 66kV via feeders 66:MAN and 81C.

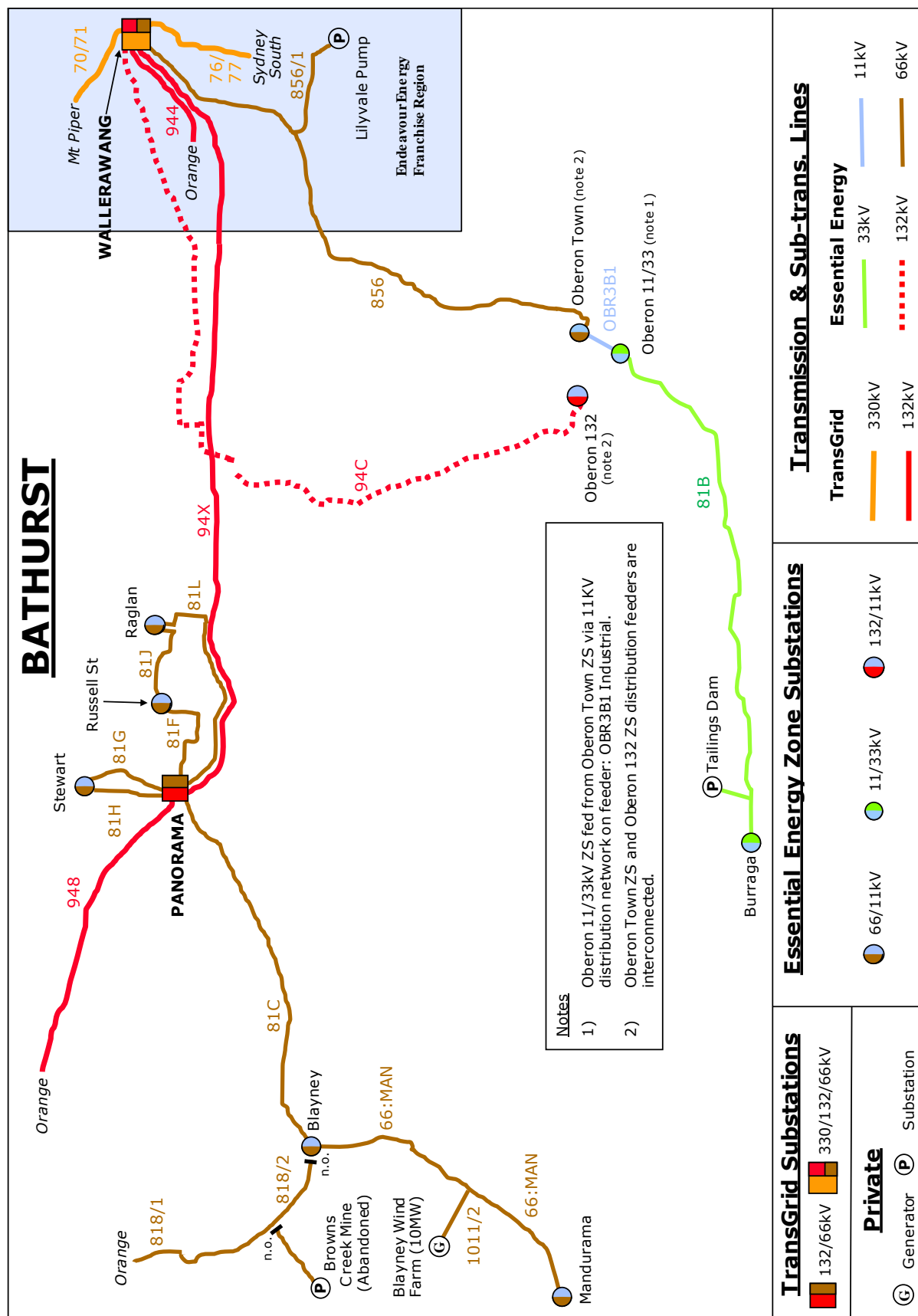
2.4.30 Oberon Supply Area

Description of Oberon area

All zone substations in the Oberon area are in the Macquarie region.

The zone substations at Oberon are supplied directly from Wallerawang via Essential Energy's 66kV and 132kV sub-transmission lines respectively.

Sub-transmission Single Line Diagram of Bathurst area



2.4.31 Parkes Supply Area

Description of Parkes area

All zone substations in the Parkes area are in the Central region.

The Parkes area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation via a 66kV 89L/89G ring to the Parkes Town zone substation with a feed to Peak Hill and Tomingley Mine Substations.

A 4.99MW solar generator is located at Peak Hill on the 11kV network, and a 4.99MW solar generator is located at Trundle on the 22kV network.

2.4.32 Forbes Supply Area

Description of Forbes area

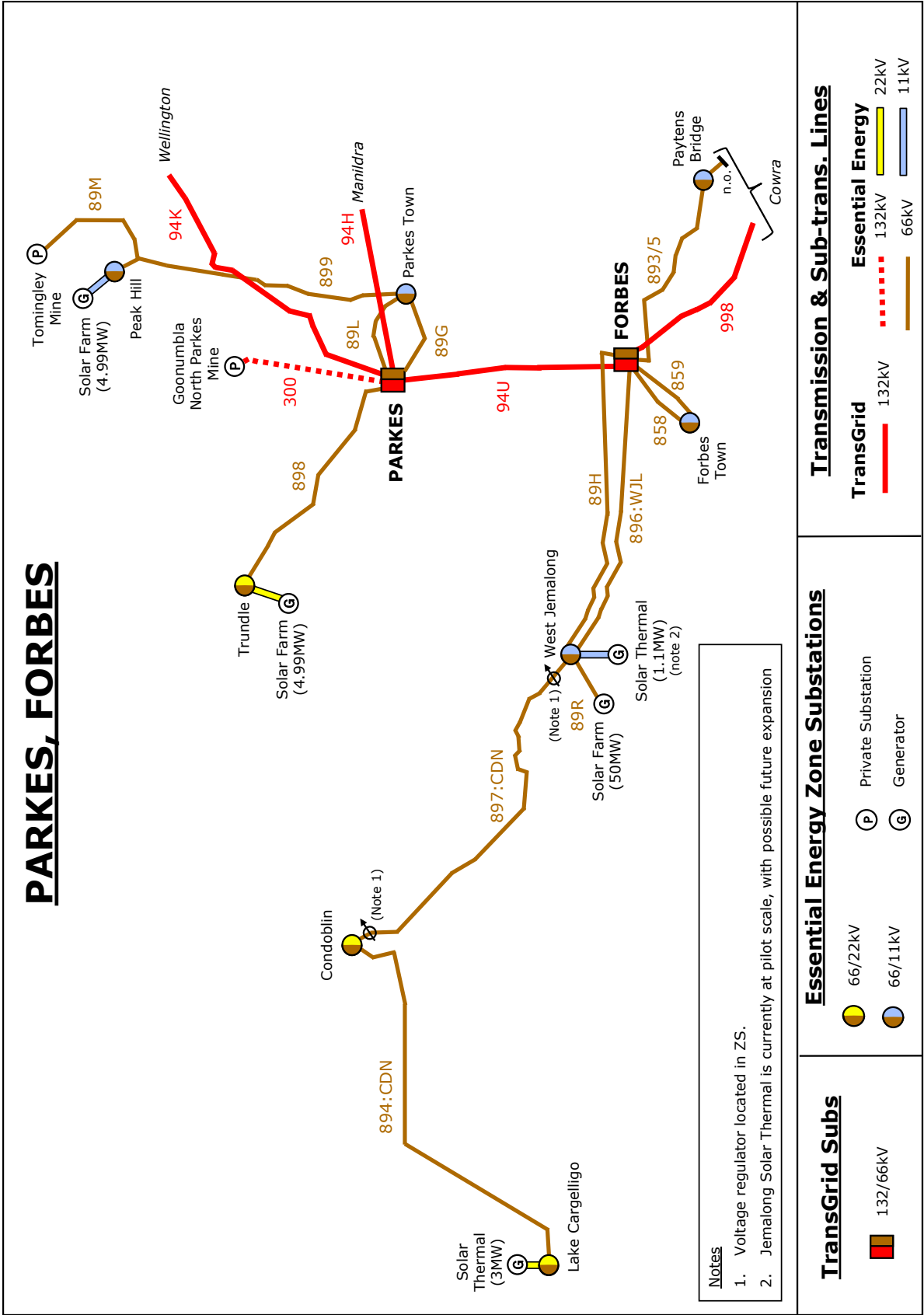
Zone substations in the Forbes area are spread across both the Riverina Slopes and Central regions.

The Forbes area sub-transmission system is supplied from Transgrid's Forbes 132/66kV sub-transmission substation.

A 50MW solar generator is located at West Jemalong and is connected to the Transgrid Forbes 132/66kV sub-transmission substation at 66kV via the feeder 89R.

A 3MW solar thermal generator is located at Lake Cargelligo on the 22kV network, and a 1.1MW solar thermal generator is located at West Jemalong on the 11kV network.

Sub-transmission Single Line Diagram of Parkes area

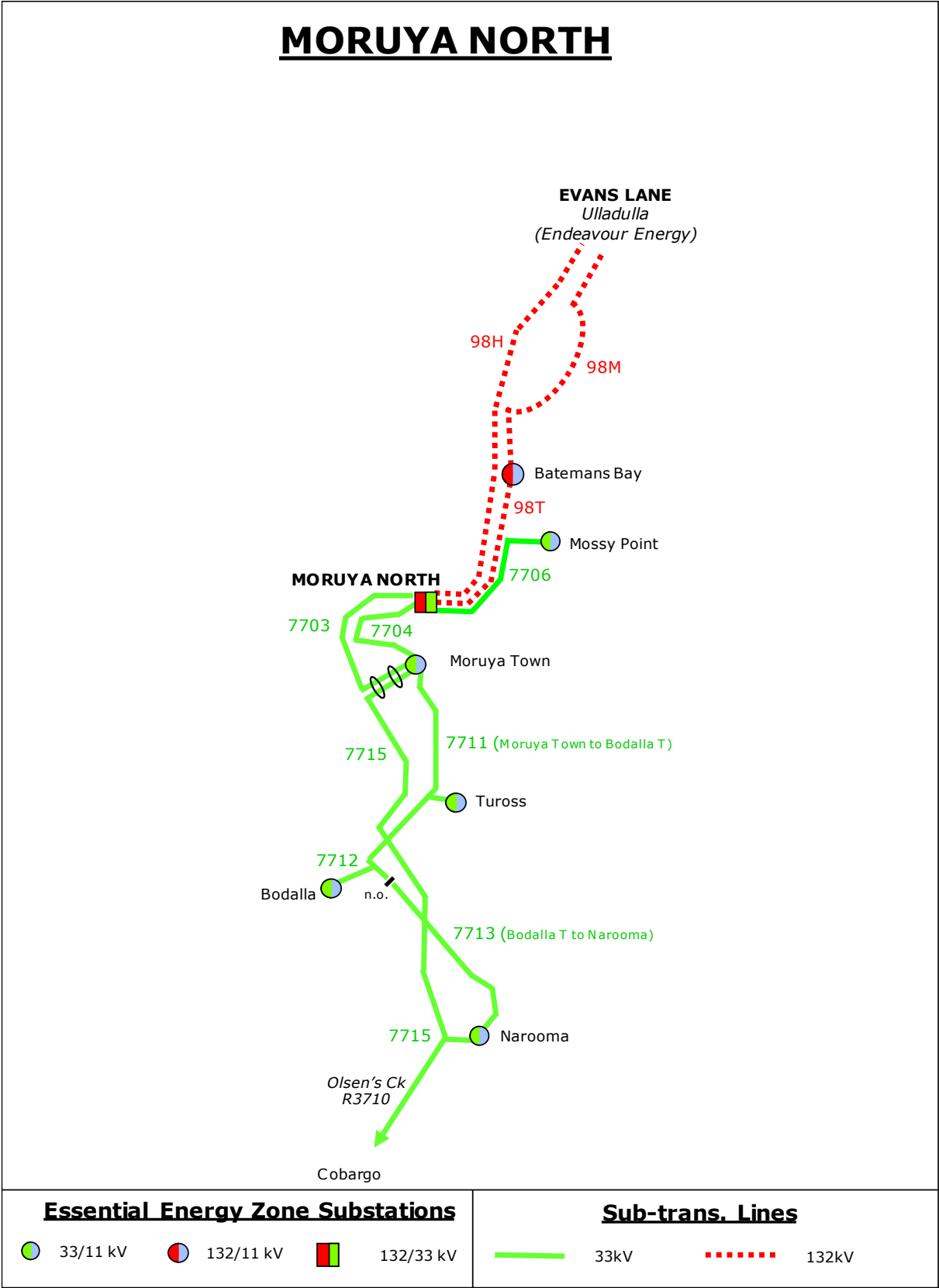


2.4.33 Moruya North Supply Area

Description of Moruya North area

All zone substations in the Moruya North area are in the South Eastern region.

Essential Energy's Moruya North sub-transmission substation is supplied via 2 x 132kV transmission lines from Endeavour Energy's 132kV transmission system that emanate from the Evans Lane switching station near Ulladulla. Essential Energy partly owns with Endeavour Energy both 132kV transmission lines from Evans Lane switching station.



2.4.34 Cooma Supply Area

Description of Cooma area

All zone substations in the Cooma area are in the South Eastern region.

The Cooma area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation at Cooma.

A 5MW hydro generator is located at Brown Mountain Hydro and is connected to Steeple Flat 132/66kV sub-transmission substation at 66kV via feeder 810.

A 114MW wind generator is located at Boco Rock wind farm and is connected to the Steeple Flat 132/66kV sub-transmission substation which is connected to Transgrid's Cooma 132/66kV sub-transmission substation at 132kV via the feeder 97R.

A 1MW hydro generator is located at Jindabyne Dam and is connected to the Jindabyne zone substation 11kV busbar via feeder JIN22.

2.4.35 Munyang Supply Area

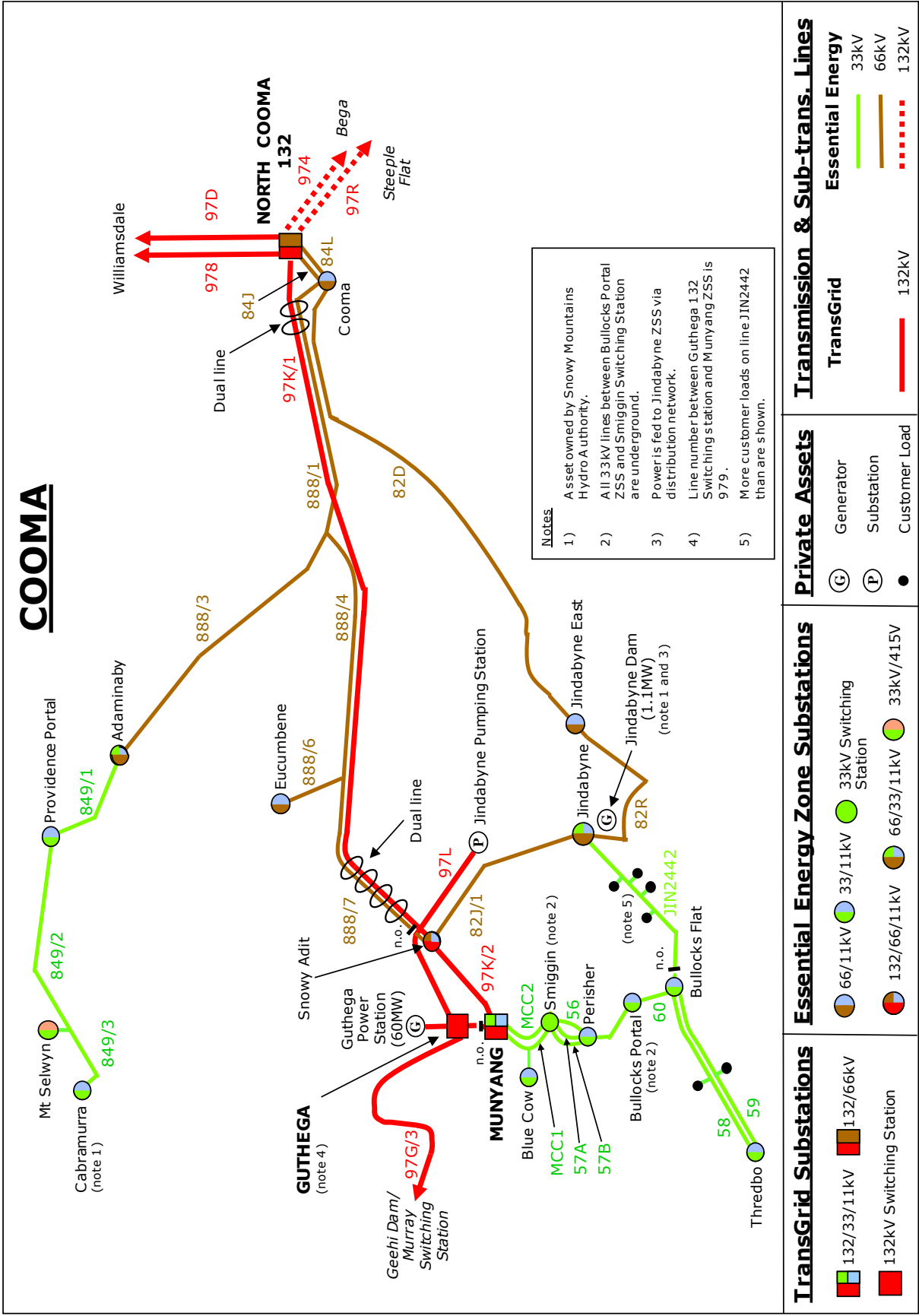
Description of Munyang area

All zone substations in the Munyang area are in the South Eastern region.

The Munyang area sub-transmission system is supplied from Transgrid's sub-transmission substation at Munyang. The majority of the Snowy Mountains winter ski resorts are supplied from the Munyang sub-transmission substation.

Essential Energy takes supply at 11kV from Snowy Mountains Hydro at the Murray transmission substation to supply the Khancoban township.

Sub-transmission Single Line Diagram of Cooma area



2.4.36 BegaSupply Area

Description of Bega area

All zone substations in the Bega area are in the South Eastern region.

Essential Energy's Bega sub-transmission substation is supplied from Transgrid's Cooma 132/66kV sub-transmission substation via two Essential Energy 132kV transmission lines.

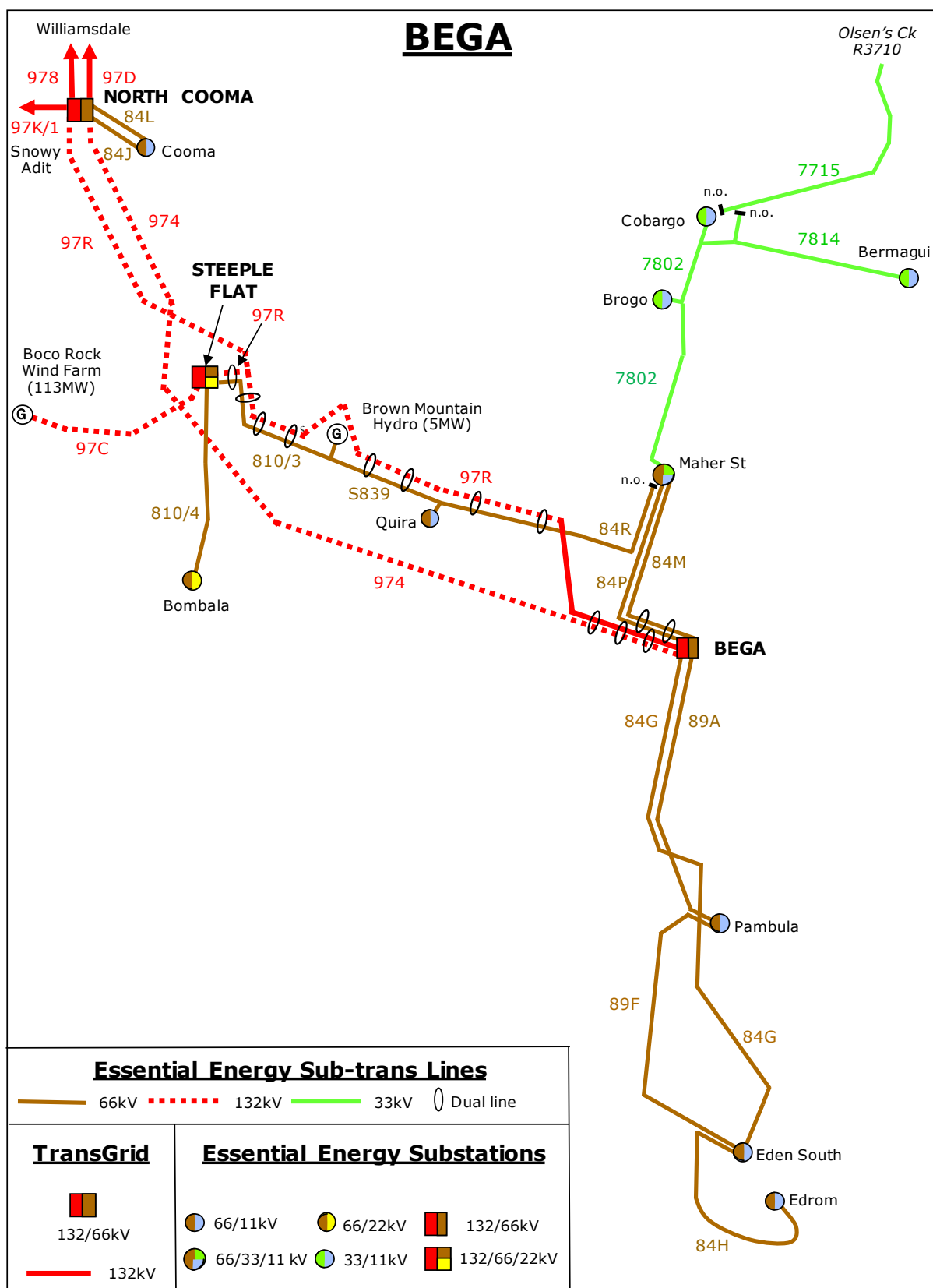
2.4.37 Steeple Flat Supply Area

Description of Steeple Flat area

All zone substations in the Steeple Flat area are in the South Eastern region.

The Steeple Flat 132/66/22kV substation is owned by Essential Energy. It receives supply via a tee off the Essential Energy 97R Cooma to Bega 132kV line. The 132/66/11kV transformer provides supply for the 66kV network to Bombala 66/22kV zone substation and connection for the Brown Mountain Generation. An 11/22kV transformer at Steeple Flat provides 22kV supply for local distribution load. Steeple Flat also provides connection for the Boco Rock wind farm to the 132kV network.

Sub-transmission Single Line Diagram of Bega area



2.4.38 Tumut Supply Area

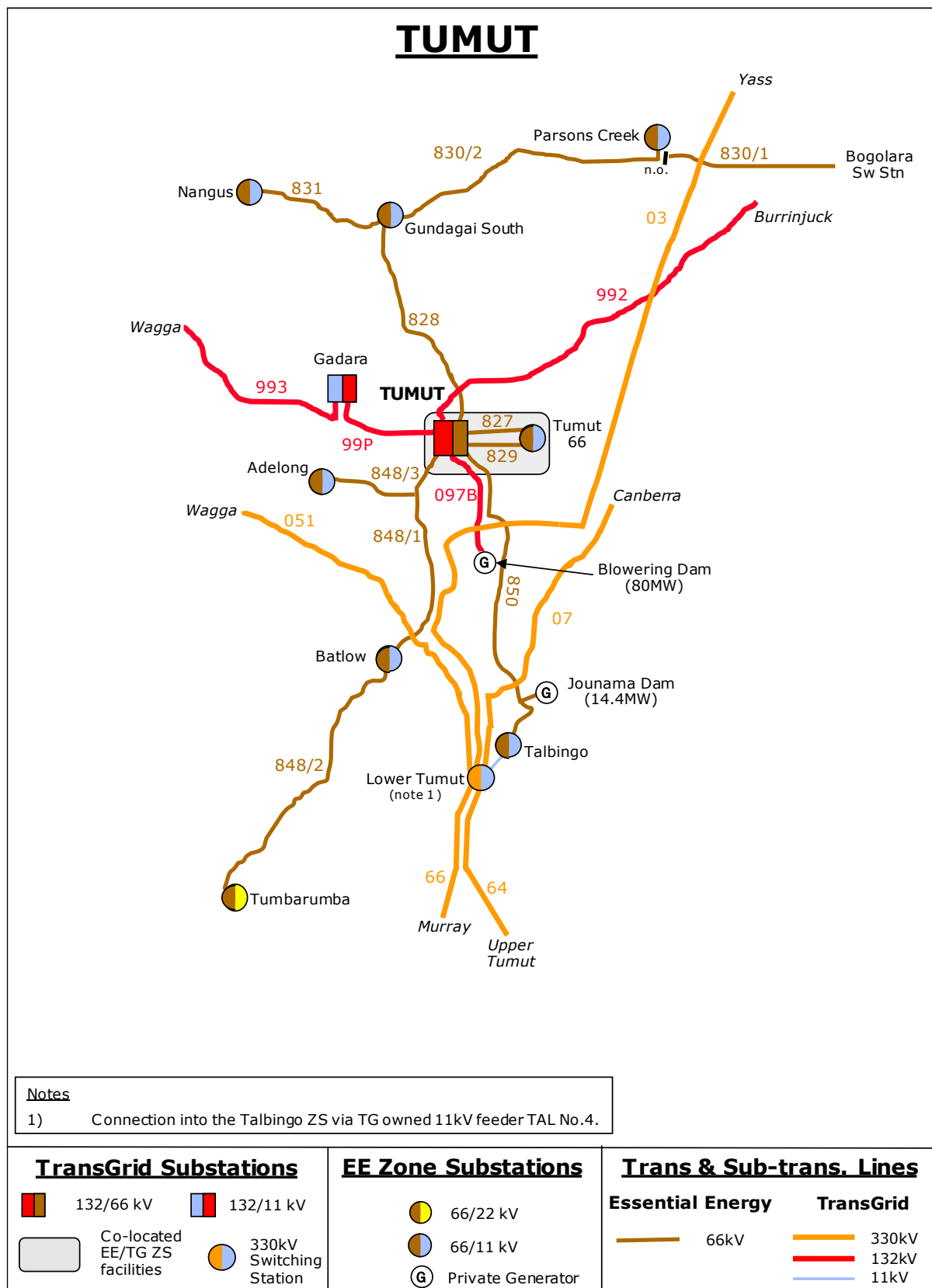
Description of Tumut area

All zone substations in the Tumut area are in the Riverina Slopes region.

The Tumut area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation.

A 15MW hydro generator is located at Jounama Dam and is connected to the Transgrid Tumut 132/66kV sub-transmission substation at 66kV via feeder 850:TAL.

Sub-transmission Single Line Diagram of Tumut area

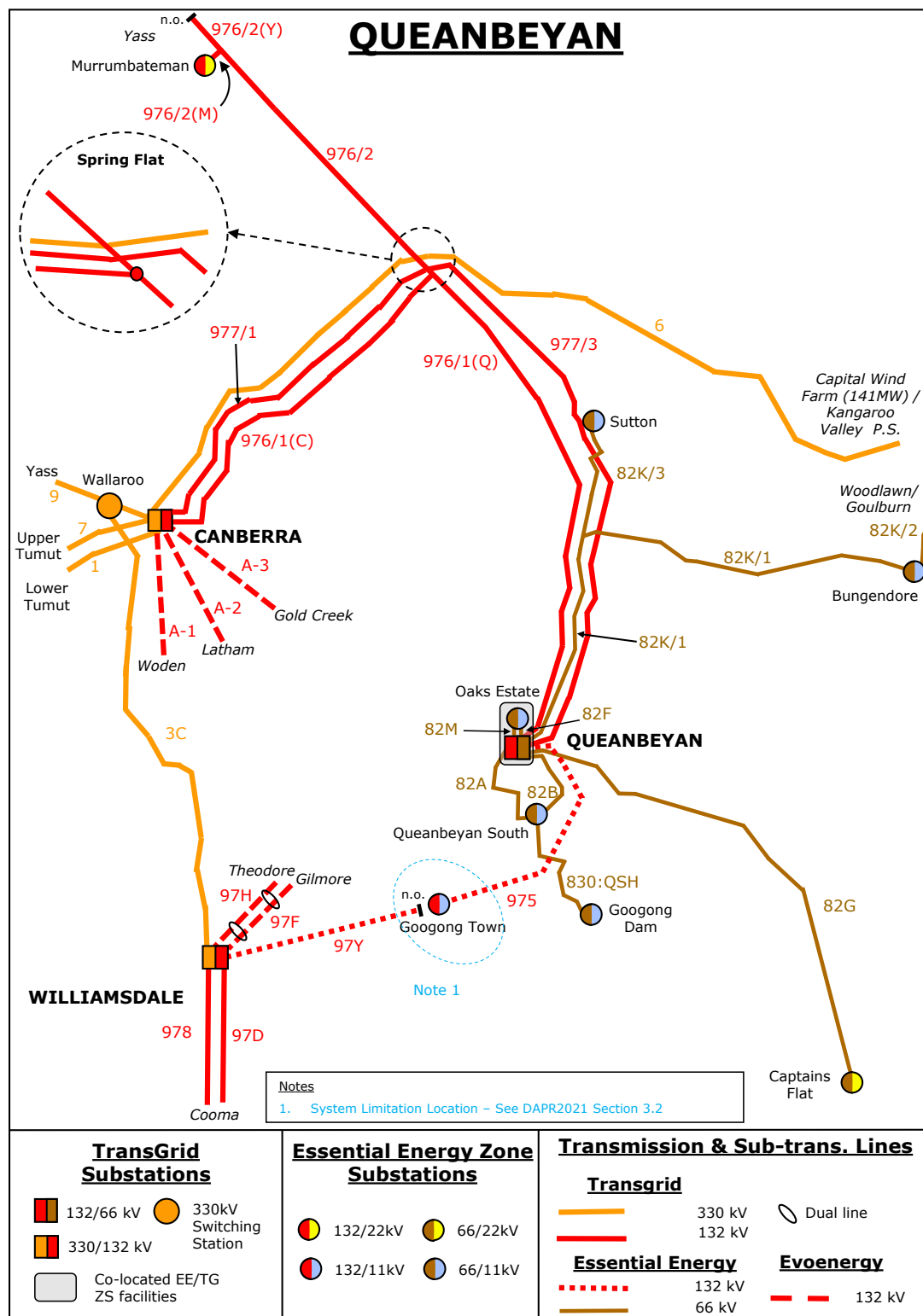


2.4.39 Queanbeyan Supply Area

Description of Queanbeyan area

All zone substations in the Queanbeyan area are in the South Eastern region. The Queanbeyan area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation.

Sub-transmission Single Line Diagram of Queanbeyan area



2.4.40 Goulburn Supply Area

Description of Goulburn area

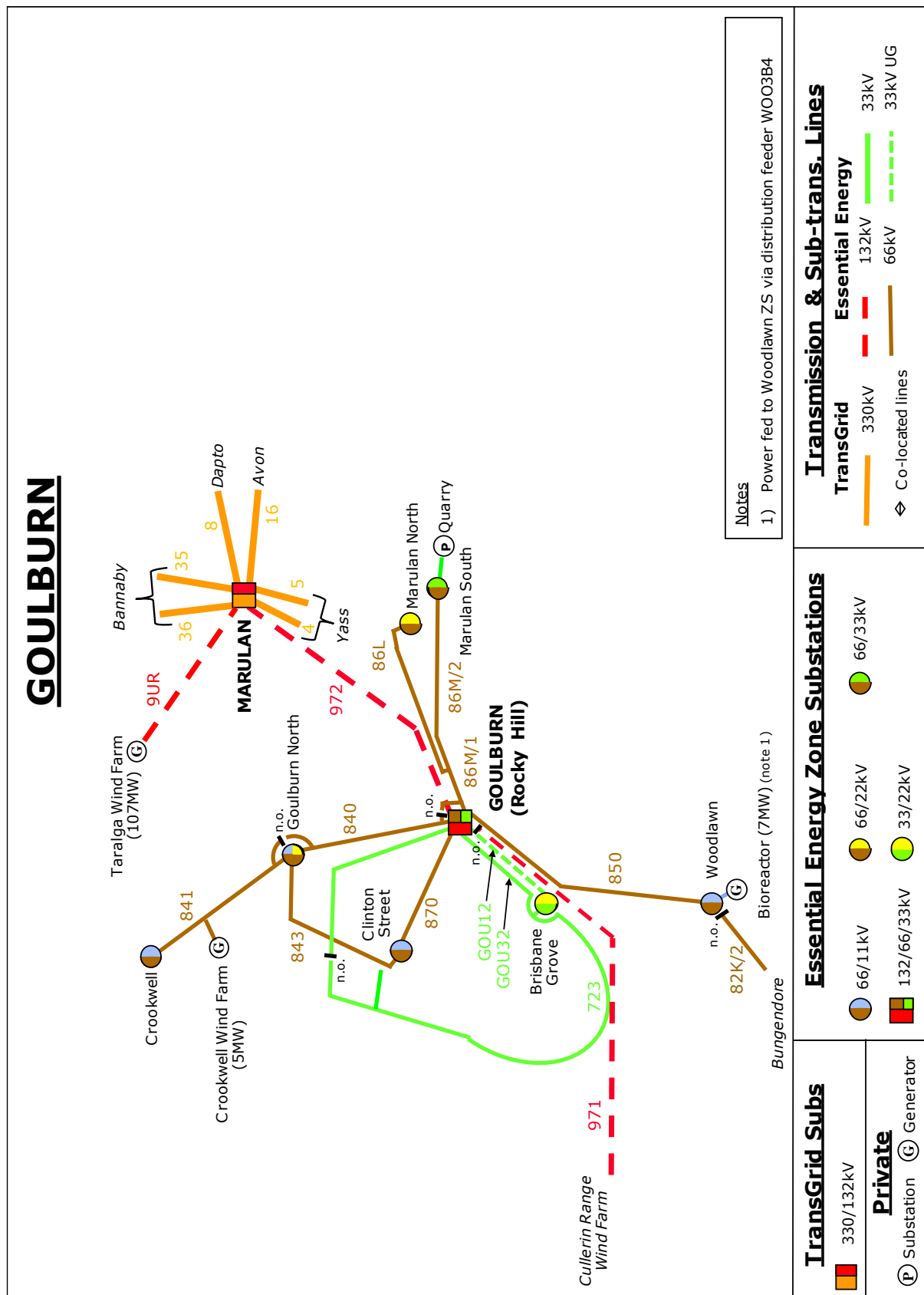
All zone substations in the Goulburn area are in the South Eastern region.

Essential Energy's Goulburn (Rocky Hill) 132/66/33kV substation is supplied via Essential Energy's 132kV transmission lines from Transgrid's sub-transmission substations at Marulan and Yass respectively.

A 7MW biomass generator is located at Woodlawn Bioreactor and is connected to the Woodlawn 66/11kV zone substation at 11kV via feeder WOO8642.

A 5MW wind generator is located at Crookwell wind farm and is connected to the Goulburn 132/66kV sub-transmission substation at 66kV via feeders 841:GBN and 840:GOU.

A 107MW wind generator is located at Taralga wind farm and is connected to the Transgrid Marulan 330/132kV sub-transmission substation at 132kV via feeder 9UR.



2.4.41 Cowra Supply Area

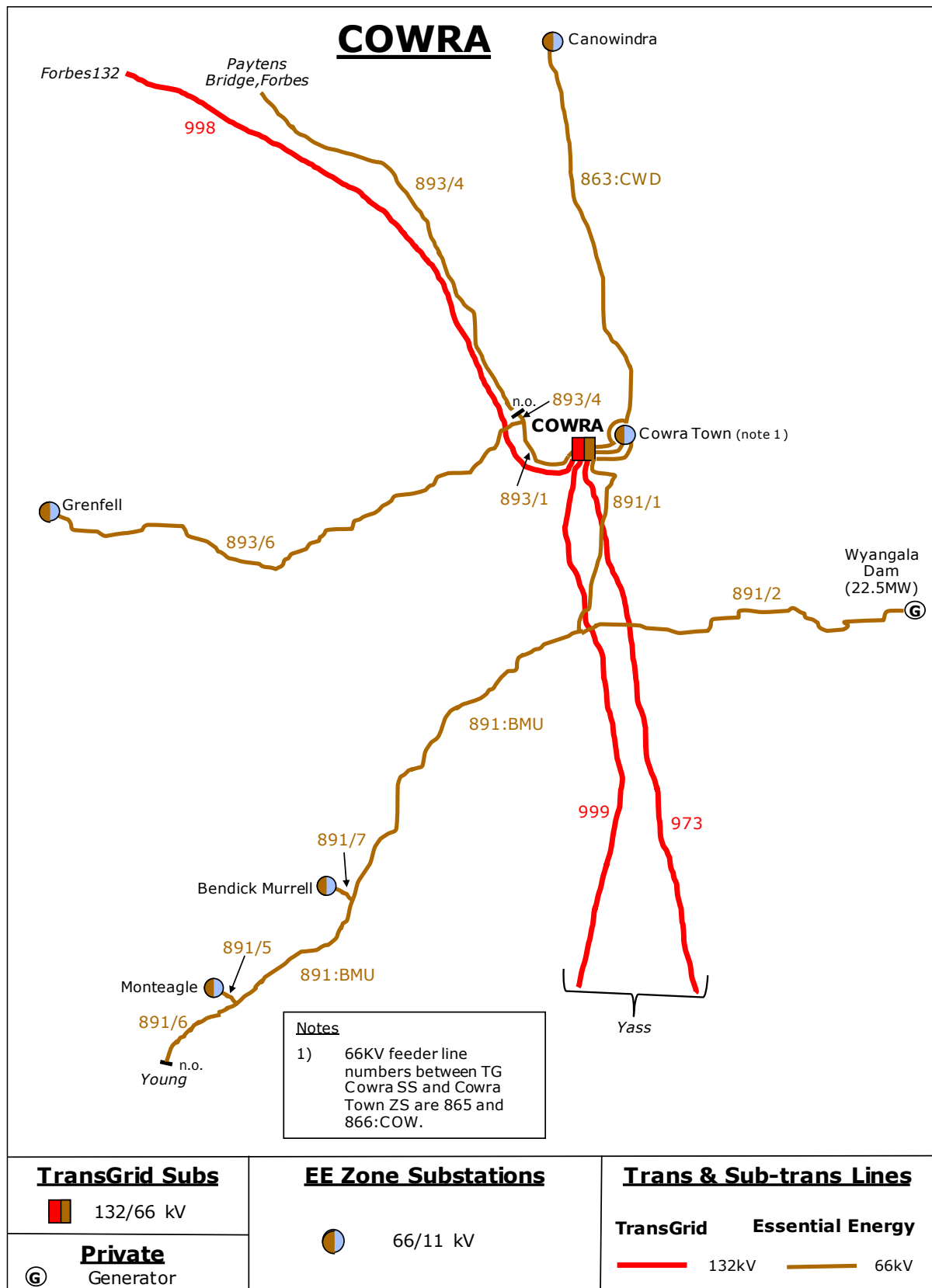
Description of Cowra area

Zone substations in the Cowra area are spread across both the Macquarie and Riverina Slopes regions.

The Cowra area sub-transmission system is supplied from Transgrid's Cowra 132/66kV sub-transmission substation. Normal 66kV system operation supplies from Cowra to Young open point and includes Bendick Murrell, Monteagle and connection to Wyangala Power Station.

A 22.5MW hydro generator is located at Wyangala Dam and is connected to the Transgrid Cowra 132/66kV sub-transmission substation at 66kV via feeder 891.

Sub-transmission Single Line Diagram of Cowra area

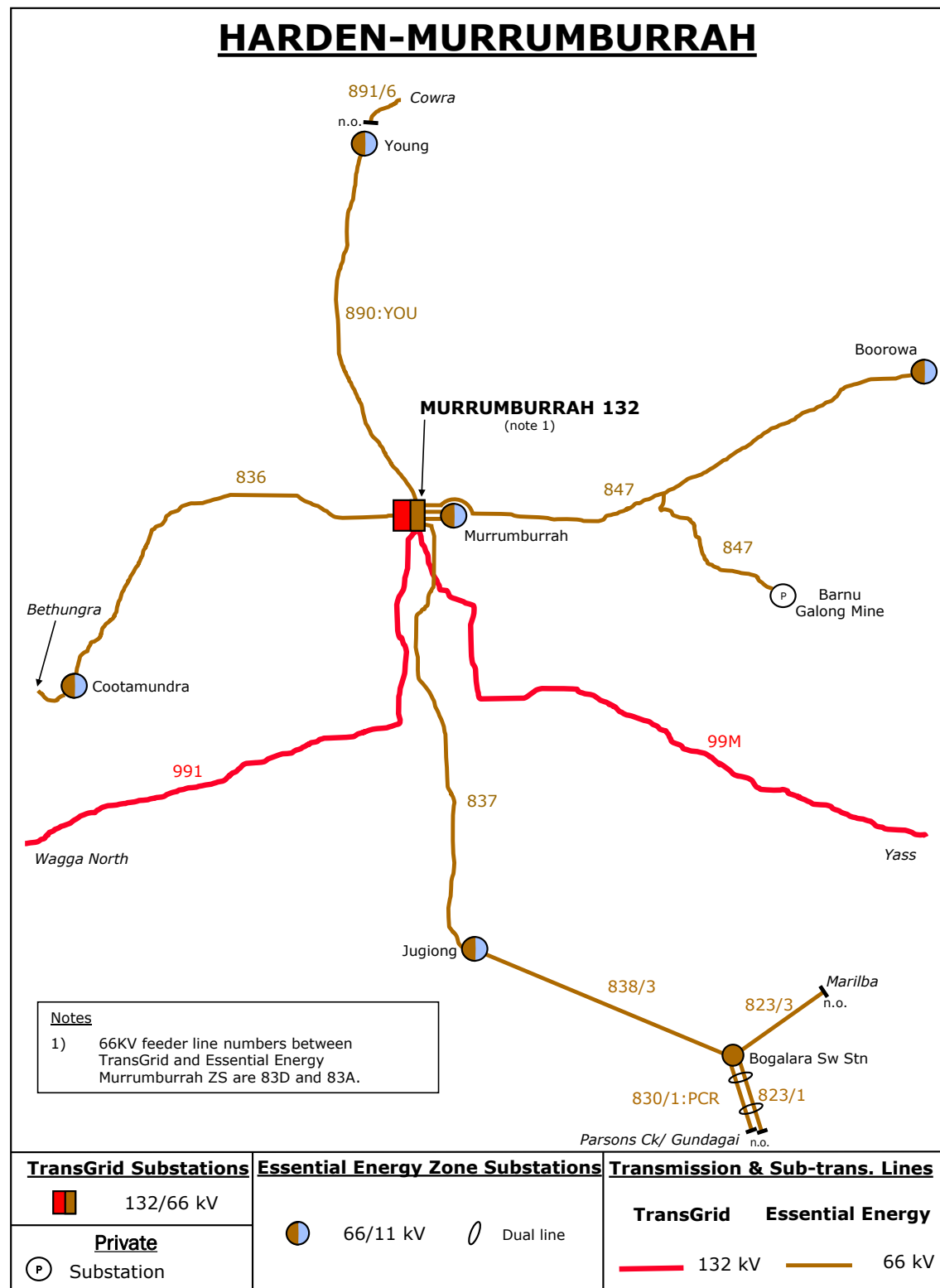


2.4.42 Murrumburrah Supply Area

Description of Murrumburrah area

All zone substations in the Murrumburrah area are in the Riverina Slopes region. The Harden-Murrumburrah area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation at Murrumburrah.

Sub-transmission Single Line Diagram of Murrumburrah area



2.4.43 Yass Supply Area

Description of Yass area

All zone substations in the Yass area are in the South Eastern region.

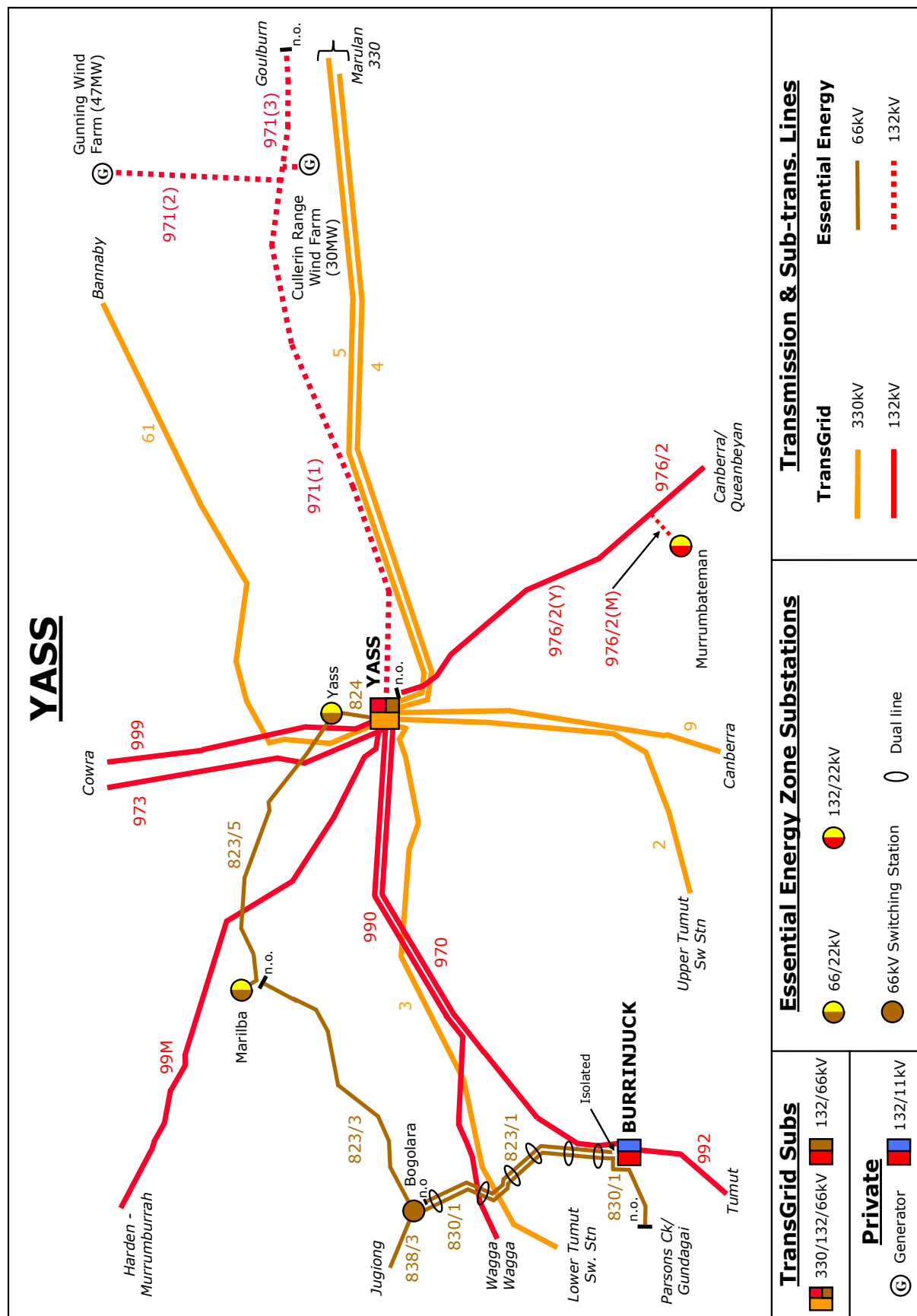
The Yass area sub-transmission system is supplied from Transgrid's 330/132/66kV sub-transmission substation.

A 30MW wind generator is located at Cullerin Range wind farm and is connected to the Transgrid Yass 330/132/66kV sub-transmission substation at 132kV via feeder 971.

A 47MW wind generator is located at Gunning wind farm and is also connected to the Transgrid Yass 330/132/66kV sub-transmission substation at 132kV via feeder 971.

There are multiple load transfer points in the Yass area to other zone substations that can be utilised with the loss of a single Yass transformer.

Sub-transmission Single Line Diagram of Yass area



2.4.44 Temora Supply Area

Description of Temora area

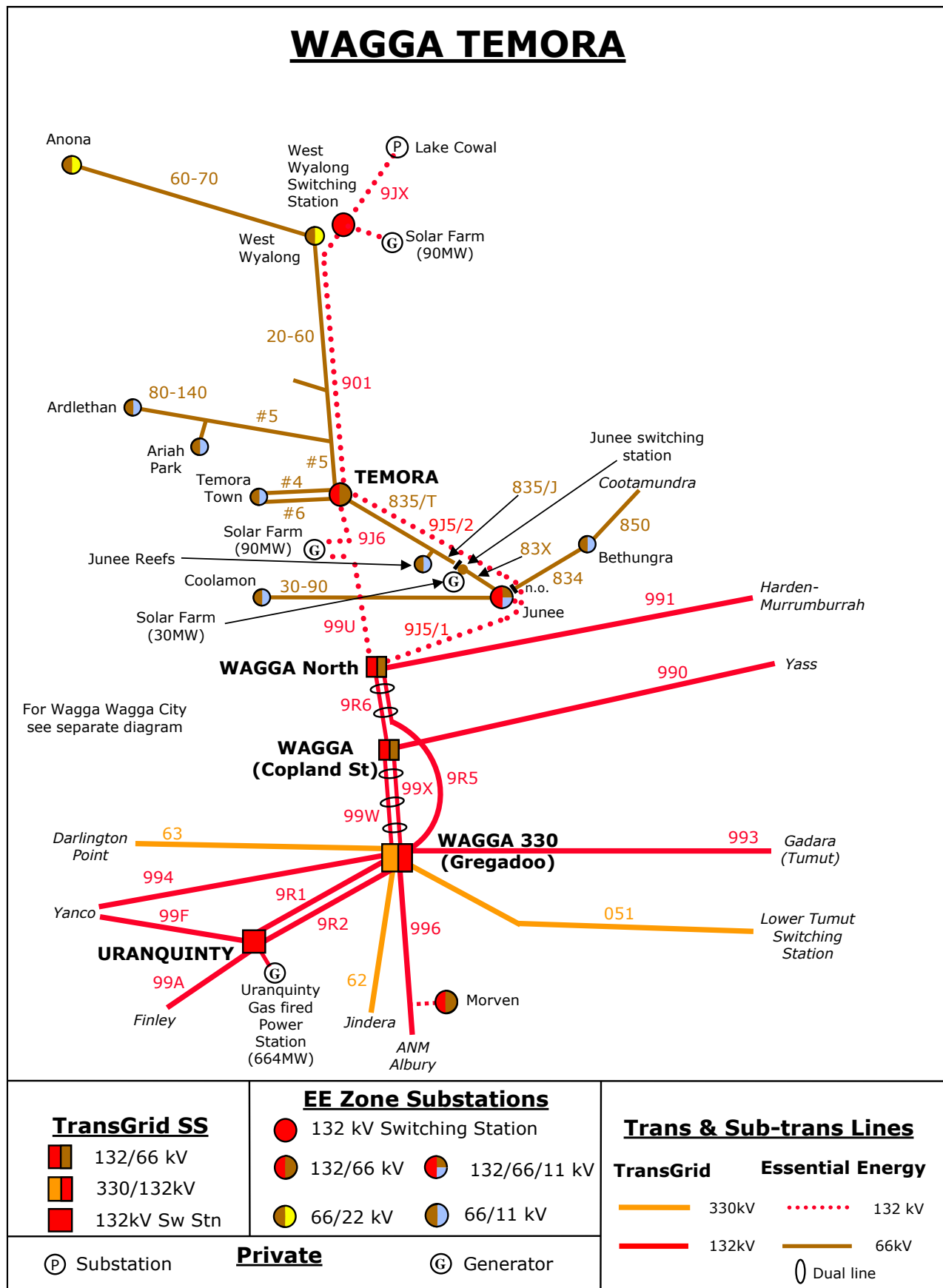
Zone substations in the Temora area are spread across both the Riverina Slopes and Central regions.

Essential Energy's Temora 132/66kV sub-transmission substation is supplied from Transgrid's Wagga Wagga North 132/66kV sub-transmission substation via two Essential Energy 132kV transmission lines.

A 90MW solar generator is located at Sebastopol and is connected to the Transgrid Wagga North 132/66kV sub-transmission substation at 132kV via feeder 99U.

A 30MW solar generator is located at Junee on the 11kV network.

Sub-transmission Single Line Diagram of Temora area



2.4.45 Wagga North Supply Area

Description of Wagga North area

All zone substations in the Wagga North area are in the Riverina Slopes region.

The Wagga Wagga area sub-transmission system is supplied from two separate Transgrid 132/66kV sub-transmission substations at Wagga Wagga (Copland St) and Wagga North.

The transmission system emanating from Wagga North supplies many smaller outlying areas.

2.4.46 Wagga Wagga (Copland St) Supply Area

Description of Wagga Wagga area

Zone substations in the Wagga Wagga area are spread across both the Riverina Slopes and Murray regions.

The Wagga Wagga area sub-transmission system is supplied from two separate Transgrid 132/66kV sub-transmission substations at Wagga Wagga (Copland St) and Wagga North.

The transmission system emanating from Wagga Wagga (Copland St) supplies the majority of the Wagga Wagga city load as well as supplying the areas as far south as Holbrook and as far west as Lockhart.

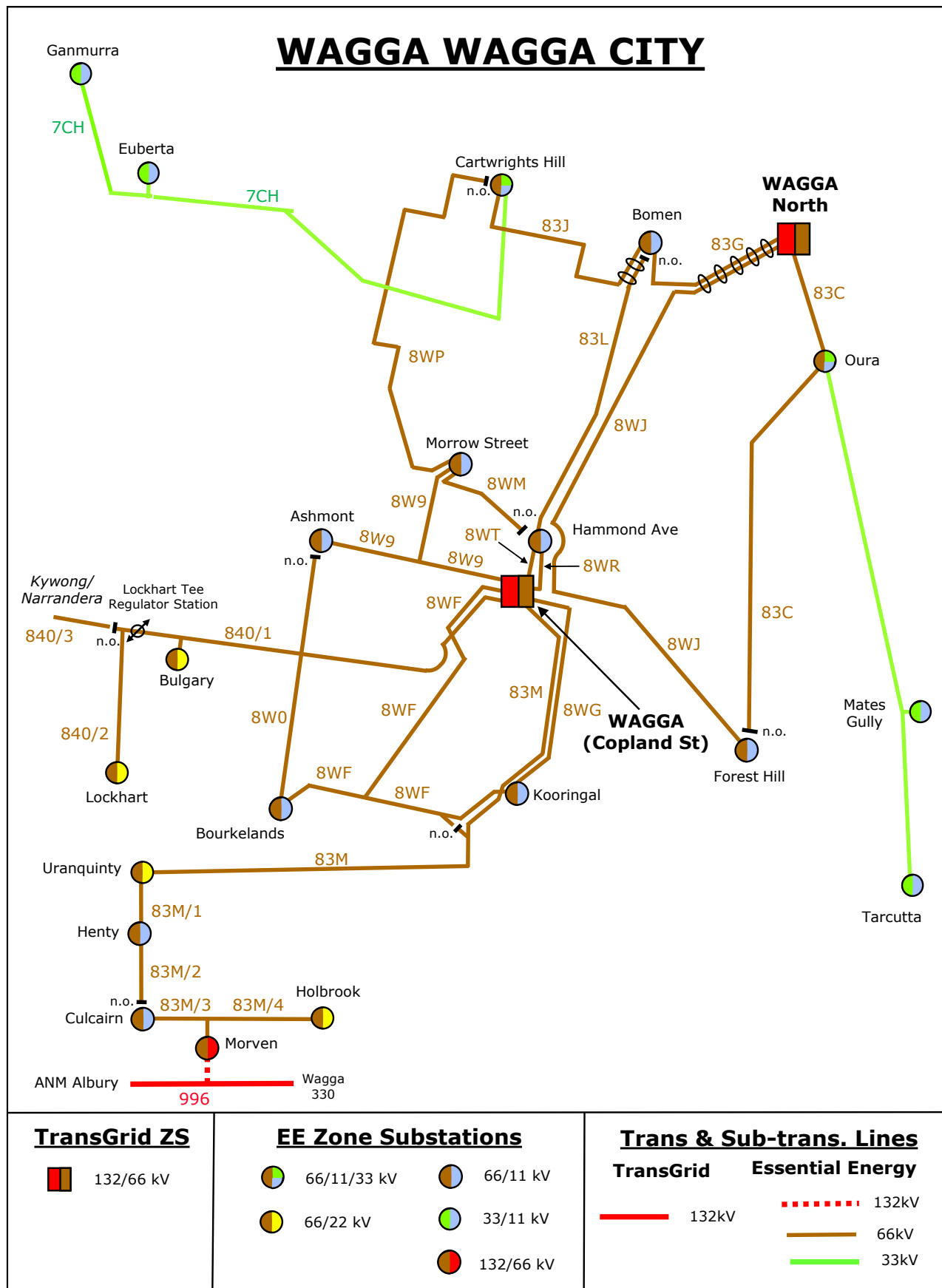
2.4.47 Morven Supply Area

Description of Morven area

All zone substations in the Morven area are in the Murray region.

The Morven 132/66kV substation is owned by Essential Energy. It receives supply via a tee off the Transgrid Wagga Wagga 330kV (Gregadoo) – Albury (ANM) 132kV line 996. Culcaim 66/11kV and Holbrook 66/22kV zone substations take normal 66kV supply from Morven and backup 66kV supply from Transgrid's Wagga Wagga 132/66kV substation (Copland St) on the Essential Energy 66kV line 83M via Uranquinty and Holbrook.

Sub-transmission Single Line Diagram of Wagga North area



2.4.48 Albury Supply Area

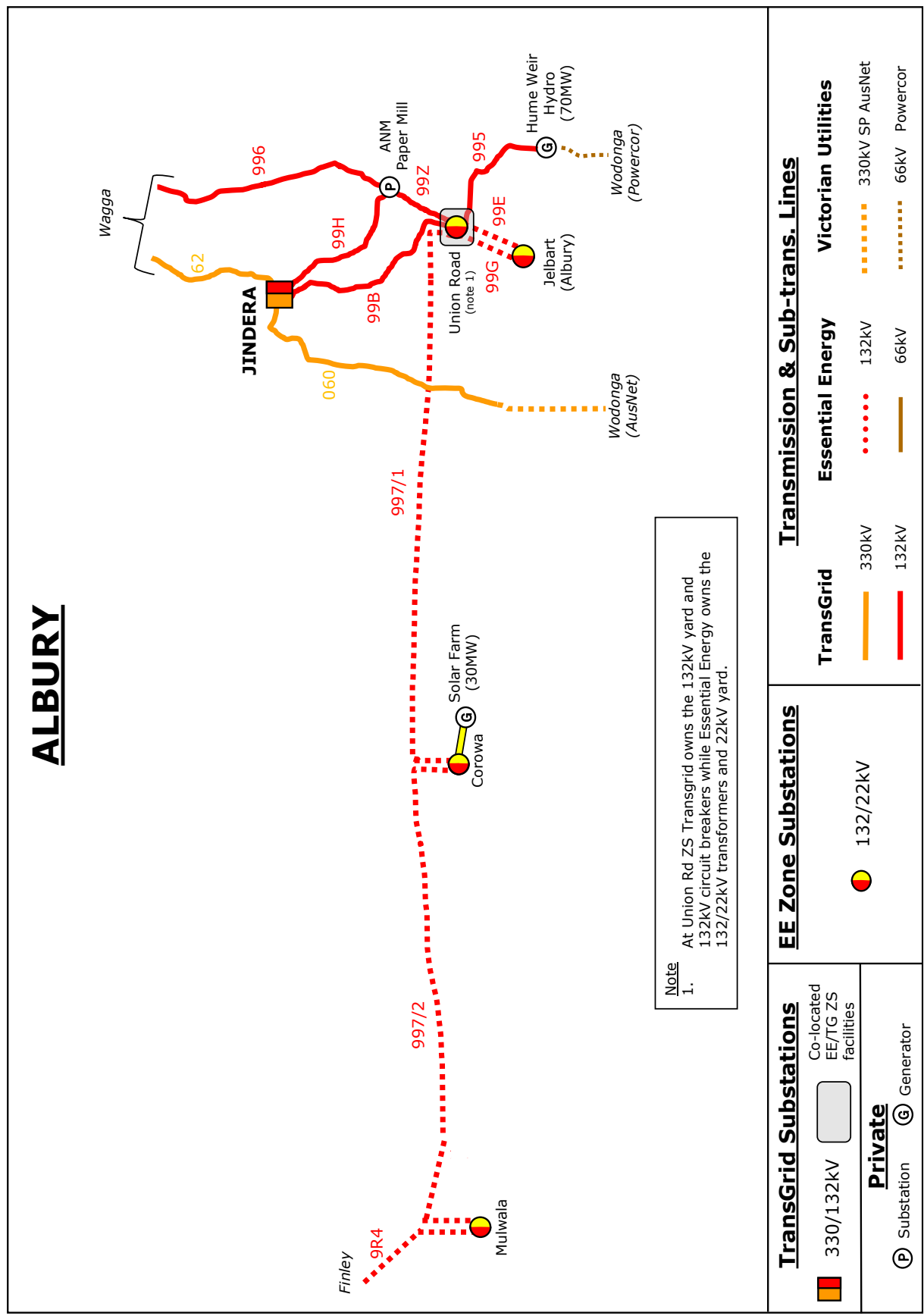
Description of Albury area

All zone substations in the Albury area are in the Murray region.

The Albury area 132kV sub-transmission system is supplied from Transgrid's Jindera 330/132kV sub-transmission substation with backup via Transgrid's 132kV line from ANM substation Ettamogah.

The Essential Energy substation of Corowa and Mulwala are supplied at 132kV from the Essential Energy 132kV powerlines connecting the Union Road substation to Transgrid's Finley 132/66kV sub-transmission substation.

A 30MW solar thermal generator is located at Corowa on the 22kV network



2.4.49 Finley Supply Area

Description of Finley area

All zone substations in the Finley area are in the Murray region.

The Finley area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation.

A 2.5MW hydro generator is located at The Drop and is connected to the Finley 66/22kV zone substation at 22kV via feeder FIN42.

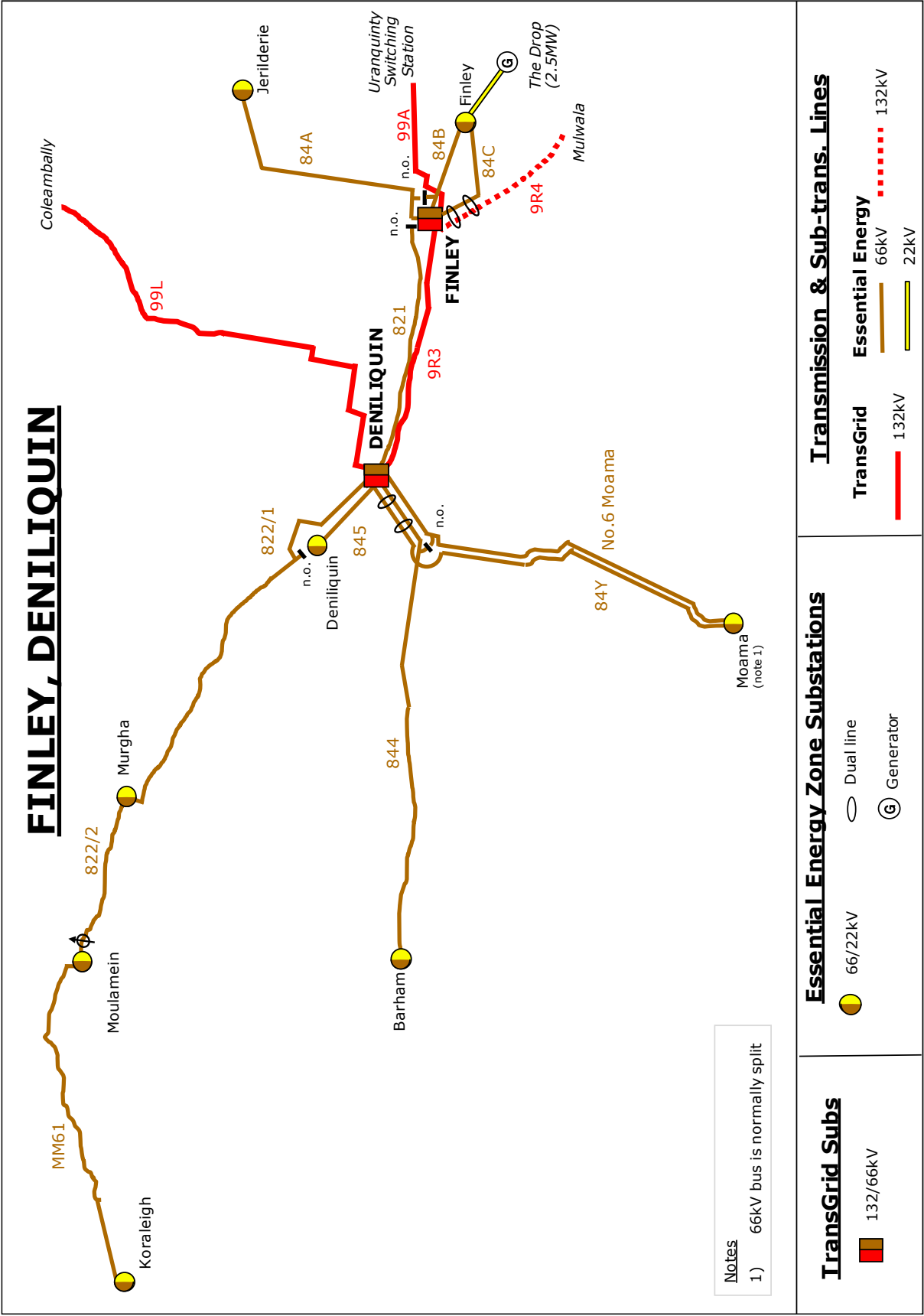
2.4.50 Deniliquin Supply Area

Description of Deniliquin area

All zone substations in the Deniliquin area are in the Murray region.

The Deniliquin area sub-transmission system is supplied from Transgrid's 132/66kV sub-transmission substation.

Sub-transmission Single Line Diagram of Finley area



2.4.51 Coleambally Supply Area

Description of Coleambally area

All zone substations in the Coleambally area are in the Central region.

Essential Energy's Coleambally 132/33kV sub-transmission substation is supplied from Transgrid's 132kV transmission powerlines 99L from Deniliquin and 99T from Darlington Point system.

2.4.52 Darlington Point Supply Area

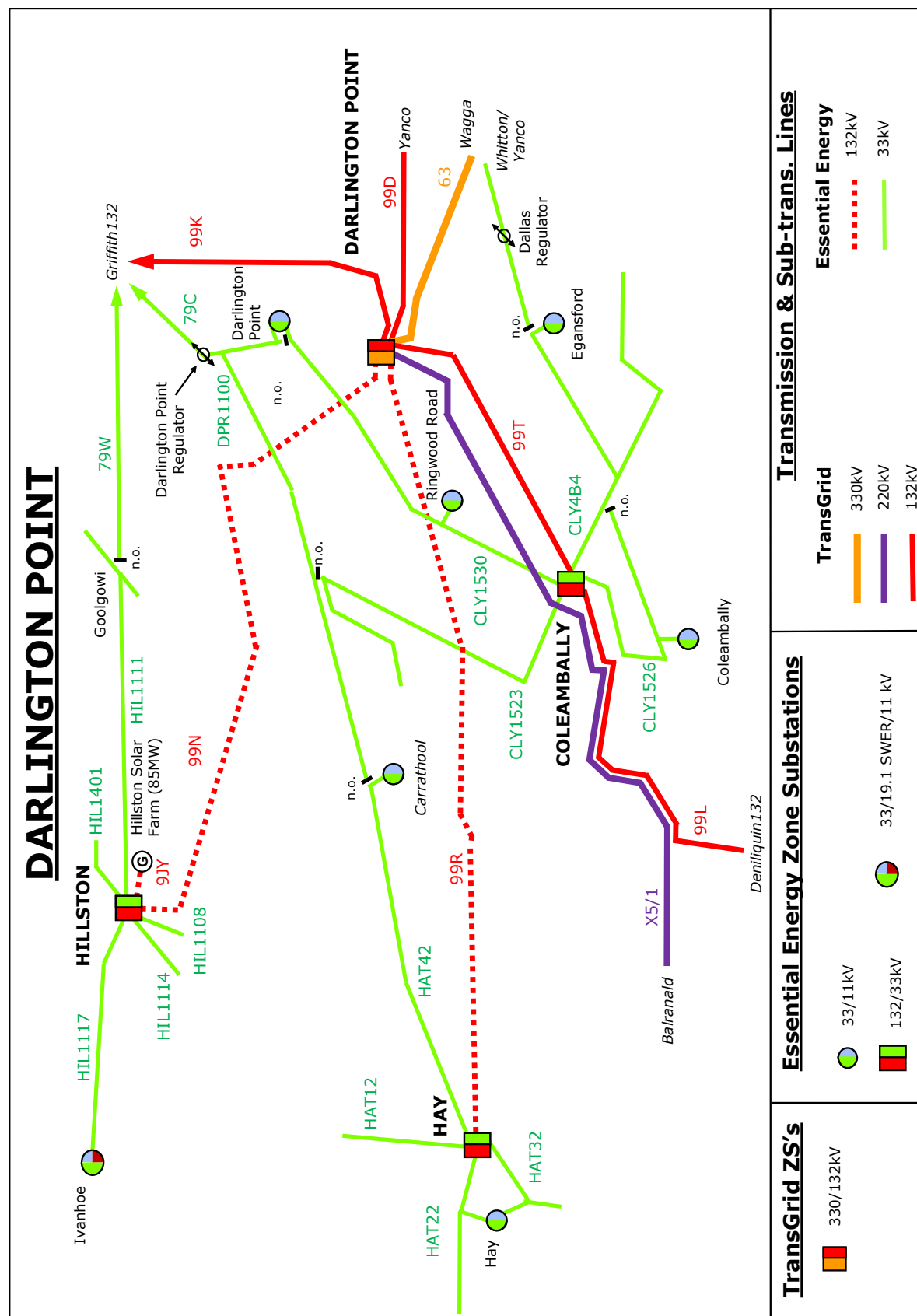
Description of Darlington Point area

All zone substations in the Darlington Point area are in the Central region.

The Darlington Point area 132kV sub-transmission system is supplied from Transgrid's 330/132kV sub-transmission substation. Essential Energy owns the 132kV transmission lines supplying Hay and Hillston substations. The 33kV sub-transmission originates from these substations.

An 85MW solar generator is located at Hillston and is connected to the Hillston 132/66kV sub-transmission substation at 132kV via feeder 9JY.

Sub-transmission Single Line Diagram of Coleambally area

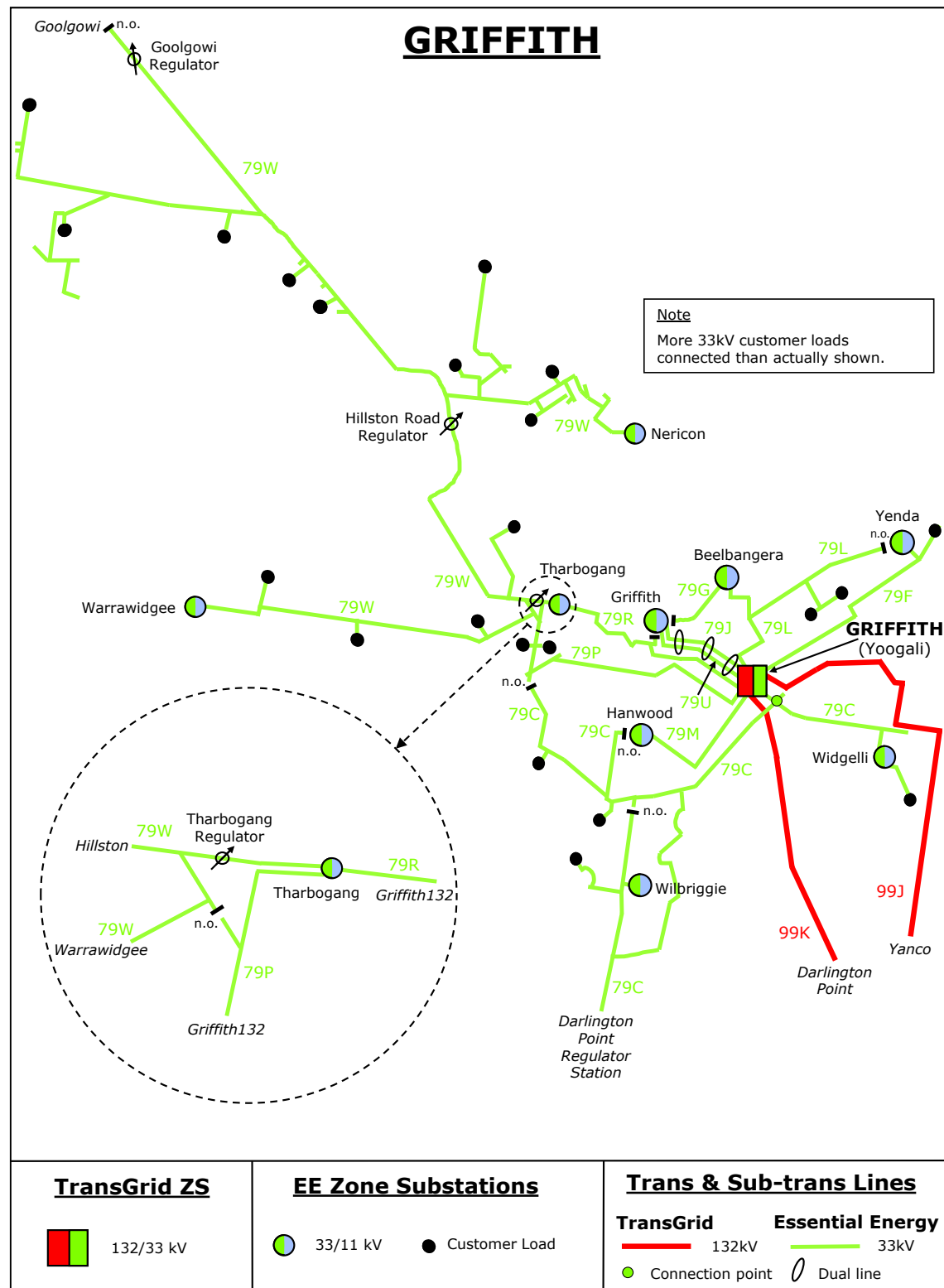


2.4.53 Griffith Supply Area

Description of Griffith area

All zone substations in the Griffith area are in the Central region. The Griffith area sub-transmission system is supplied from Transgrid's 132/33kV sub-transmission substation.

Sub-transmission Single Line Diagram of Griffith area



2.4.54 Yanco Supply Area

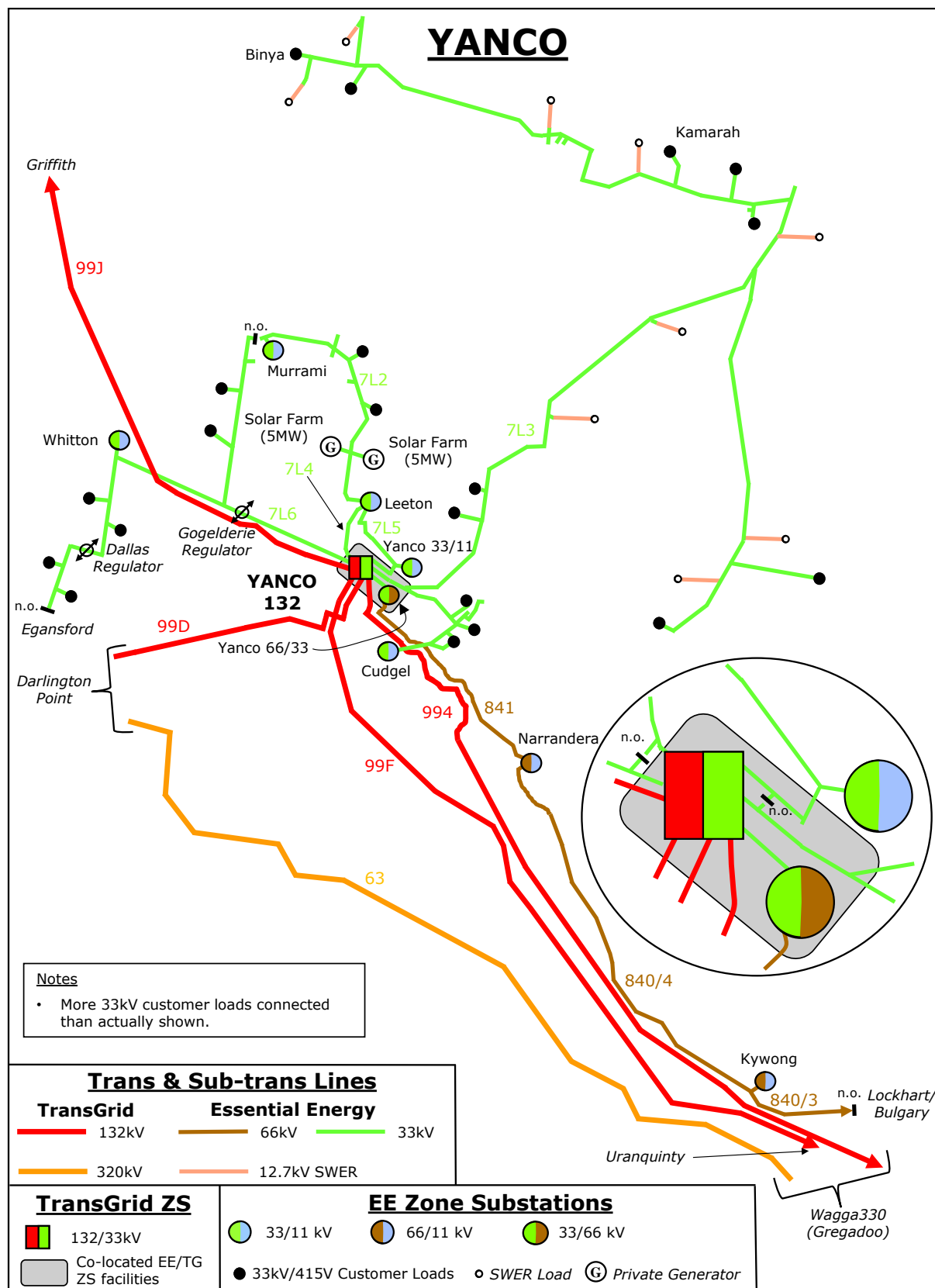
Description of Yanco area

All zone substations in the Yanco area are in the Central region.

The Yanco area sub-transmission system is supplied from Transgrid's 132/33/66kV sub-transmission substation. The 66kV sub-transmission system originates from Transgrid's 132/33/66kV sub-transmission substation via an Essential Energy 33/66kV transformer.

Two 5MW solar generators are located near Leeton and are connected to the Yanco 132/33kV sub-transmission substation at 33kV via feeder 7L2.

Sub-transmission Single Line Diagram of Yanco area



2.4.55 Buronga Supply Area

Description of Buronga area

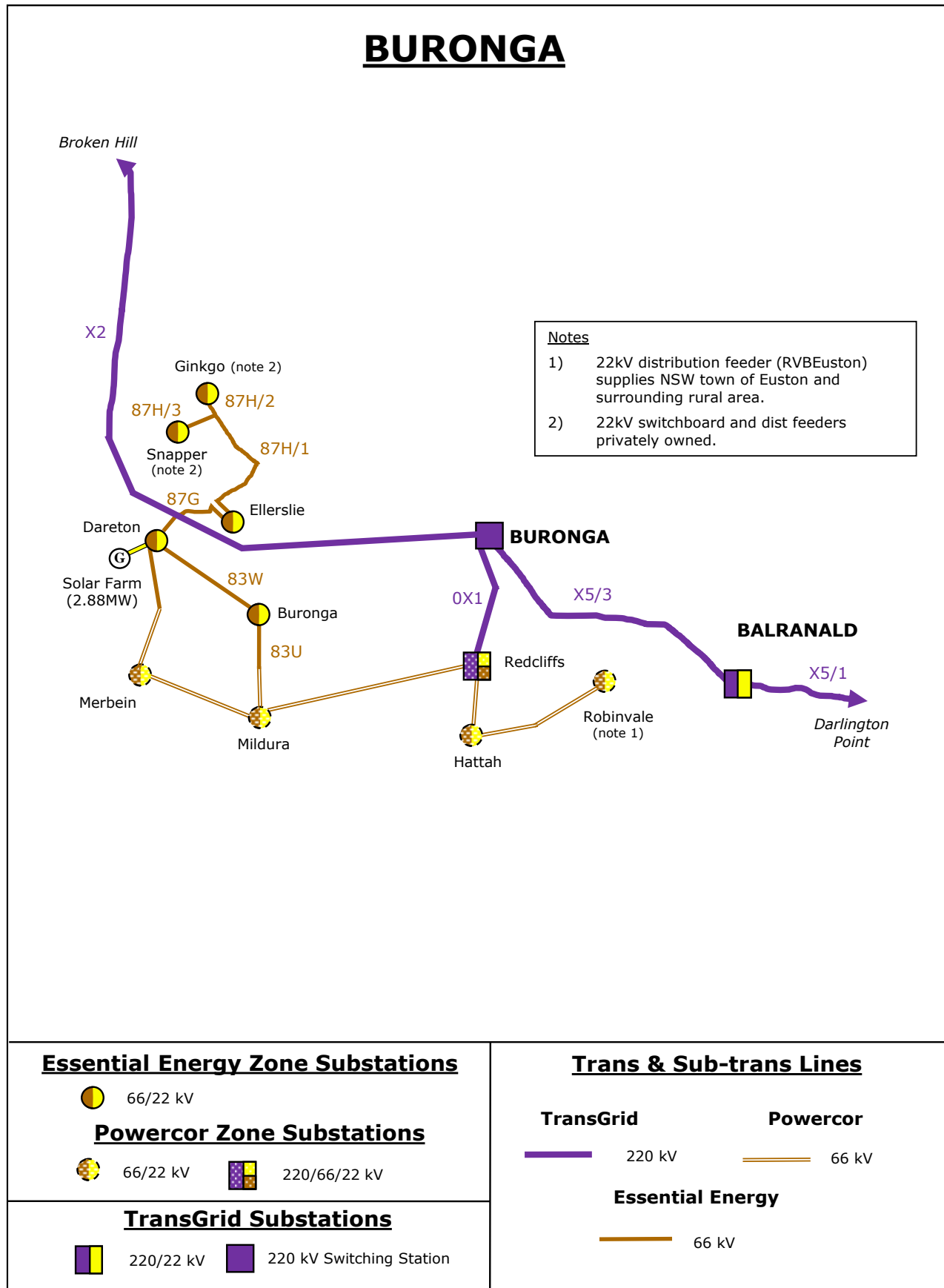
All zone substations in the Buronga area are in the Murray region.

Supply to the Dareton, Wentworth and Buronga areas originates from the Powercor 66kV sub-transmission substations at Merbein and Mildura in Victoria, which is in turn supplied from the Red Cliffs Victoria 220/66kV sub-transmission substation south east of Mildura.

The Balranald area is supplied from Transgrid's 220/22kV substation. Backup supply is seasonal limited via Moulamein 22kV system.

A 3.3MW solar generator is located at Dareton on the 22kV network.

Sub-transmission Single Line Diagram of Buronga area



2.5 Future Connection Point

A 330/11kV connection to Transgrid was commissioned December 2022 for the resupply of Cabramurra and Selwyn.

FUTURE Transmission/Distribution Substation Demand Forecast										
Substation	kV	Proposed Location	Forecast		Forecast (MVA)					Estimated Commissioning Date
			Summer	PF	22/23	23/24	24/25	25/26	26/27	
			Winter	PF	2023	2024	2025	2026	2027	
Upper Tumut	330/11	Cabramurra	Summer	0.99	3.0	3.0	3.0	3.0	3.0	Dec 2022
			Winter	1.00	4.4	4.4	4.4	4.4	4.4	

2.6 Transmission – Distribution Connection Point Load Forecast

Connection point load forecasts are available in the data attachment. The embedded generation includes all major generation capacity but excludes the rooftop PV generation (which is shown against the individual zone substation forecasts).

2.7 Forecast of Reliability Target Performance

The 2021/22 financial year is the seventh year since the introduction of the Service Target Performance Incentive Scheme (STPIS) to Essential Energy. The STPIS provides incentives for improved normalised reliability performance and penalises reduced normalised reliability performance against System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) targets.

The following targets have been set by the AER for the network performance component of STPIS for the period 2019/20 - 2023/24. These targets are based on the average performance level of Essential Energy's network over the previous regulatory period.

Table 4 – STPIS targets 2019/20 to 2023/24

Feeder Category	Unplanned SAIDI (minutes)	Unplanned SAIFI (interruptions)
Urban	72.99	0.896
Short Rural	204.16	1.852
Long Rural	445.52	2.935

In addition to the targets listed in Table 4, are the Reliability and Performance licence conditions set out by the Independent Pricing and Regulatory Tribunal (IPART) that impose reliability performance standards on electricity distributors. These are categorised by different feeder lengths and load densities. Reliability performance standards were met for all feeder categories in 2021/22 except Long Rural SAIDI. Essential Energy uses this data to make efficient investment decisions for the sub-transmission and distribution networks.

According to the normalised index that covers the average number of interruptions (SAIFI) and the average time customers are without electricity (SAIDI) during the year, Essential Energy's network reliability in the reporting period increased compared to the previous period.

Customers were without electricity for an average of 218 minutes in 2021/22 (SAIDI), compared to a figure of 215 minutes in 2020/21. The average frequency of interruptions per customer (SAIFI) was 1.607 in 2021/22, compared to a figure of 1.71 in 2020/21. The 2021/22 year was affected by a number of major event days, 12 in total, due to an extraordinary amount of storms and flooding events across the state.

3. IDENTIFIED SYSTEM LIMITATIONS

A major part of the planning process involves performing network analysis using the latest demand forecast to establish network performance under different loading and network configurations that relate to the planning criteria outlined in Essential Energy's licence conditions and internal guidelines.

The process identifies whether the network performance obligations are satisfied within the forward planning period or if corrective action is required to address a network limitation. It should be noted that limitations identified in this report have been assessed under the network conditions and licence requirements pertaining at the time of assembly and are subject to review in the event of any significant change to either. Essential Energy defines the normal cyclic ratings for zone substation transformers as 110 per cent of nameplate rating in summer and 120 per cent of nameplate rating in winter.

Only primary distribution feeder limitations where network proposals have been developed are included in this section. A distribution feeder strategic review is underway to provide more comprehensive advice in subsequent reports.

The NER requires DNSPs to investigate non-network options by utilising a thorough consultation process to facilitate input into the planning of major network upgrades. This provides opportunity for interested parties and the community to submit options and ideas allowing for the development of cost-effective demand management and other system support options.

The NER calls for a 'screening test' to be performed for all capital investments above \$6M to determine if a non-network option is credible and should be investigated further. If a non-network option is deemed to be feasible, Essential Energy will conduct a detailed investigation to determine the objective and targets for a non-network option to be successful and publish this information in a Non-Network Options Report. Alternatively, a notice must be published if it is determined on reasonable grounds there are no feasible non-network options to address the investment.

The AER published a distribution system limitation template in June 2017 to enable the delivery of useable and consistent information to non-network service providers for addressing identified network needs. The template is designed to improve the quality of the information provided and enable rapid evaluation of alternative solutions. All investments provided within this template have not yet been assessed for internal or external non-network solutions.

This section outlines the identified network limitations and provides an indication of the potential network solutions against which the credible non-network alternatives will be assessed.

The detailed list of identified limitations, asset ratings and whole feeder historical load traces are published in separate files to this report. These supplementary files are available for download on the Essential Energy website <https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/regulatory-reports-and-network-information>.

3.1 Sub-transmission Feeder Limitations

IDENTIFIED SUBTRANSMISSION FEEDER LIMITATIONS						
Region	Feeder Number and Name	System Limitation			Potential Load Transfer	Load reduction required for 1 year deferral (MW)
		Details	Driver	Timing		
<u>Southern</u> Griffith	<u>79W</u> Goolgowi	Voltage and thermal limitations under contingent conditions	Capacity/ Growth	Jun-24	0	2

3.2 Sub-transmission and Zone Substation Limitations

Essential Energy has no identified limitations within sub-transmission substations and zone substations.

3.3 Primary Distribution Feeder Limitations

Essential Energy primary distribution feeder investments have been included within the latest limitation template provided by ISF, and a summary of these identified limitations are included below. The detailed information for these limitations are included in supplementary documents available for download on the Essential Energy website <https://www.essentialenergy.com.au/our-network/network-pricing-and-regulatory-reporting/regulatory-reports-and-network-information>.

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>Central</u>	Griffith	GFH3B5 Jensen Rd	Asset Condition	Griffith Rae Rd Conductor upgrade	\$ 117,269	Jul-23	1.99 MVA	2023 - 2.35 MVA; 2024 - 2.35 MVA; 2025 - 2.35 MVA; 2026 - 2.35 MVA; 2027 - 2.35 MVA	2023 - 0.6 MW; 2024 - 0.6 MW; 2025 - 0.6 MW; 2026 - 0.6 MW; 2027 - 0.6 MW
<u>Central</u>	Ivanhoe	IVA1325 Nth SWER	Reliability	Ivanhoe Kewell East 97-4807 IVA1325 consider SAPS	\$ 311,233	Jul-23	0.02 MVA	2023 - 0.02 MVA; 2024 - 0.02 MVA; 2025 - 0.02 MVA; 2026 - 0.02 MVA; 2027 - 0.02 MVA	2023 - 0.02 MW; 2024 - 0.02 MW; 2025 - 0.02 MW; 2026 - 0.02 MW; 2027 - 0.02 MW
<u>Central</u>	Parkes Town	PKT3B3 Telescope	Asset Condition	Replace failing 11kV steel conductor	\$ 214,000	Jun-24	0.06 MVA	2023 - 0.5 MVA; 2024 - 0.5 MVA; 2025 - 0.5 MVA; 2026 - 0.5 MVA; 2027 - 0.5 MVA	2023 - 0.06 MW; 2024 - 0.06 MW; 2025 - 0.06 MW; 2026 - 0.06 MW; 2027 - 0.06 MW
<u>Central</u>	West Jemalong	WJL3B2 Warroo	Asset Condition	Replacement of 7/064HDCU mainline conductor	\$ 336,973	Jul-23	0.39 MVA	2023 - 0.98 MVA; 2024 - 0.98 MVA; 2025 - 0.98 MVA; 2026 - 0.98 MVA; 2027 - 0.98 MVA	2023 - 0.37 MW; 2024 - 0.38 MW; 2025 - 0.38 MW; 2026 - 0.39 MW; 2027 - 0.4 MW
<u>Central</u>	West Jemalong	WJL3B2 Warroo	Asset Condition	Replacement of 7/064HDCU mainline conductor	\$ 219,559	Jul-23	0.38 MVA	2023 - 0.98 MVA; 2024 - 0.98 MVA; 2025 - 0.98 MVA; 2026 - 0.98 MVA; 2027 - 0.98 MVA	2023 - 0.36 MW; 2024 - 0.36 MW; 2025 - 0.36 MW; 2026 - 0.36 MW; 2027 - 0.36 MW
<u>Central</u>	Yenda	YEN3B3 Bilbul	Reliability	Myall Park BEE1346-YEN3B3 Tie	\$ 69,256	Jun-23	2 MVA	2023 - 2.09 MVA; 2024 - 2.09 MVA; 2025 - 2.09 MVA; 2026 - 2.09 MVA; 2027 - 2.09 MVA	2023 - 0.5 MW; 2024 - 0.5 MW; 2025 - 0.5 MW; 2026 - 0.5 MW; 2027 - 0.5 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>Coastal</u>	Murwillumbah	MWN3B2 Norco	Capacity	Murwillumbah Buchanan St create HV interconnector MWN3B2/9	\$ 386,455	Jul-23	2.35 MVA	2023 - 2.04 MVA; 2024 - 2.04 MVA; 2025 - 2.04 MVA; 2026 - 2.04 MVA; 2027 - 2.04 MVA	2023 - 2.26 MW; 2024 - 2.31 MW; 2025 - 2.36 MW; 2026 - 2.41 MW; 2027 - 2.47 MW
<u>Coastal</u>	Terranora 11kV	TNA3B1 Bilambil Hts	Reliability	By overbuilding the existing alignment along Peninsula Drive with 11kV, a more robust and flexible network is available to greatly reduce customers affected by outages	\$ 208,855	Jun-24	2.8 MVA	2023 - 2.09 MVA; 2024 - 2.09 MVA; 2025 - 2.09 MVA; 2026 - 2.09 MVA; 2027 - 2.09 MVA	2023 - 3.66 MW; 2024 - 3.7 MW; 2025 - 3.74 MW; 2026 - 3.78 MW; 2027 - 3.81 MW
<u>Macquarie</u>	Russell Street	BTH3B11 Bentinck St	Asset Condition	Bathurst replace 350 metres underground faulty cable city centre	\$ 350,000	Mar-23	0 MVA	2023 - 5.33 MVA; 2024 - 5.33 MVA; 2025 - 5.33 MVA; 2026 - 5.33 MVA; 2027 - 5.33 MVA	2023 - 1.71 MW; 2024 - 1.71 MW; 2025 - 1.71 MW; 2026 - 1.71 MW; 2027 - 1.71 MW
<u>Macquarie</u>	Russell Street	BTH62 Mitchell College	Voltage	Investment to upgrade 4kms of 7/0.134AAC to 19/3.75AAC from pole 8535 023 College Rd to pole 16376 023 Vale Rd Bathurst to 19/3.75AAC to address voltage issues on this feeder	\$ 251,258	Jul-23	0.17 MVA	2023 - 3.52 MVA; 2024 - 3.52 MVA; 2025 - 3.52 MVA; 2026 - 3.52 MVA; 2027 - 3.52 MVA	2023 - 0.5 MW; 2024 - 0.5 MW; 2025 - 0.5 MW; 2026 - 0.5 MW; 2027 - 0.5 MW
<u>Macquarie</u>	Russell Street	BTH82 Lloyds Rd	Capacity	Investment to upgrade 4kms of 7/0.134AAC to 19/3.75AAC from pole 8535 023 College Rd to pole 16376 023 Vale Rd Bathurst to 19/3.75AAC to address voltage issues on this feeder	\$ 251,258	Feb-24	1.5 MVA	2023 - 1.21 MVA; 2024 - 1.21 MVA; 2025 - 1.21 MVA; 2026 - 1.21 MVA; 2027 - 1.21 MVA	2023 - 2.6 MW; 2024 - 2.6 MW; 2025 - 2.6 MW; 2026 - 2.6 MW; 2027 - 2.6 MW
<u>Macquarie</u>	Oberon Town	OBR3B5 Oberon Town	Safety	Oberon Zone Substation Backup protection constraints	\$ 407,453	Jul-23	2.76 MVA	2023 - 2.88 MVA; 2024 - 2.88 MVA; 2025 - 2.88 MVA; 2026 - 2.88 MVA; 2027 - 2.88 MVA	2023 - 2.65 MW; 2024 - 2.64 MW; 2025 - 2.65 MW; 2026 - 2.65 MW; 2027 - 2.65 MW
<u>Mid North Coast</u>	Lake Cathie	LKC7781 Cathie Sth	Capacity	Wallum Drv Seascape Lake Cathie thermal overload & reliability	\$ 375,407	Jan-26	3.4 MVA	2023 - 2.78 MVA; 2024 - 2.78 MVA; 2025 - 2.78 MVA; 2026 - 2.78 MVA; 2027 - 2.78 MVA	2023 - 2.84 MW; 2024 - 2.98 MW; 2025 - 3.09 MW; 2026 - 3.21 MW; 2027 - 3.33 MW
<u>Mid North Coast</u>	Tea Gardens	TEA3B4 Tea Gardens	Reliability	UG - Create 11 kV link Spinifex Ave Tea Gardens 88-82432, 1600 m	\$ 1,294,904	May-24	1.5 MVA	2023 - 3.95 MVA; 2024 - 3.95 MVA; 2025 - 3.95 MVA; 2026 - 3.95 MVA; 2027 - 3.95 MVA	2023 - 1.2 MW; 2024 - 1.22 MW; 2025 - 1.25 MW; 2026 - 1.27 MW; 2027 - 1.3 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>Murray</u>	Union Rd	ALU12 Lavington East	Performance Monitoring	HV Metering TX Replacement - DSI HOLDINGS PTY LTD,	\$ 293,640	Jul-23	3.47 MVA	2023 - 5.93 MVA; 2024 - 5.93 MVA; 2025 - 5.93 MVA; 2026 - 5.93 MVA; 2027 - 5.93 MVA	2023 - 3.47 MW; 2024 - 3.48 MW; 2025 - 3.49 MW; 2026 - 3.5 MW; 2027 - 3.5 MW
<u>Murray</u>	Ellerslie	ELL8B2 Pooncarie	Reliability	Buronga - Consider SAPS replacement of 8-645012	\$ 302,366	Jun-24	2.26 MVA	2023 - 2.99 MVA; 2024 - 2.99 MVA; 2025 - 2.99 MVA; 2026 - 2.99 MVA; 2027 - 2.99 MVA	2023 - 0.01 MW; 2024 - 0.01 MW; 2025 - 0.01 MW; 2026 - 0.01 MW; 2027 - 0.01 MW
<u>Murray</u>	Holbrook	HOL1890 Wantagong/Woomargama	Asset Condition	Holbrook, Yensches Rd spur, 22kV reconduct, EOL	\$ 362,000	Jul-23	0.78 MVA	2023 - 1.78 MVA; 2024 - 1.78 MVA; 2025 - 1.78 MVA; 2026 - 1.78 MVA; 2027 - 1.78 MVA	2023 - 0.03 MW; 2024 - 0.03 MW; 2025 - 0.03 MW; 2026 - 0.03 MW; 2027 - 0.03 MW
<u>North Western</u>	Gilgandra	GID22 Rural Nth/Sth/West	Asset Condition	Gilgandra GID22-1 22 kV OH Conductor End of Life	\$ 235,374	Jun-23	2.4 MVA	2023 - 0.84 MVA; 2024 - 0.84 MVA; 2025 - 0.84 MVA; 2026 - 0.84 MVA; 2027 - 0.84 MVA	2023 - 2.37 MW; 2024 - 2.37 MW; 2025 - 2.38 MW; 2026 - 2.38 MW; 2027 - 2.37 MW
<u>North Western</u>	Gilgandra	GID42 Town No.2	Reliability	Gilgandra HV tie GID12 to GID42 Reliability	\$ 86,036	Jun-23	0 MVA	2023 - 2.42 MVA; 2024 - 2.42 MVA; 2025 - 2.42 MVA; 2026 - 2.42 MVA; 2027 - 2.42 MVA	2023 - 2.4 MW; 2024 - 2.41 MW; 2025 - 2.41 MW; 2026 - 2.42 MW; 2027 - 2.41 MW
<u>North Western</u>	Mt Gipps 33kV	MTG4B1 Tibooburra Backbone Line	Voltage	Broken Hill - 6-V10926 Remote Comms	\$ 19,124	Jun-24	1.25 MVA	2023 - 7.3 MVA; 2024 - 7.3 MVA; 2025 - 7.3 MVA; 2026 - 7.3 MVA; 2027 - 7.3 MVA	2023 - 0 MW; 2024 - 0 MW; 2025 - 0 MW; 2026 - 0 MW; 2027 - 0 MW
<u>North Western</u>	Mt Gipps 33kV	MTG4B1 Tibooburra Backbone Line	Reliability	Broken Hill - Consider SAPS replacement of 6-12940	\$ 224,098	Jun-24	1.25 MVA	2023 - 7.3 MVA; 2024 - 7.3 MVA; 2025 - 7.3 MVA; 2026 - 7.3 MVA; 2027 - 7.3 MVA	2023 - 0.02 MW; 2024 - 0.02 MW; 2025 - 0.02 MW; 2026 - 0.02 MW; 2027 - 0.02 MW
<u>North Western</u>	Wilcannia 33kV	WLC4B1 White Cliffs	Safety	Wilcannia - Underground Network alterations White Cliffs	\$ 331,693	Jun-24	0.71 MVA	2023 - 8.62 MVA; 2024 - 8.62 MVA; 2025 - 8.62 MVA; 2026 - 8.62 MVA; 2027 - 8.62 MVA	2023 - 0.3 MW; 2024 - 0.3 MW; 2025 - 0.3 MW; 2026 - 0.3 MW; 2027 - 0.3 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
Northern Tablelands	Attunga	ATA3B2 Somerton	Asset Condition	Attunga Pontibah Top Somerton Rd 941764 Encroachment	\$ 84,661	Jul-24	0.2 MVA	2023 - 0.46 MVA; 2024 - 0.46 MVA; 2025 - 0.46 MVA; 2026 - 0.46 MVA; 2027 - 0.46 MVA	2023 - 0.18 MW; 2024 - 0.18 MW; 2025 - 0.18 MW; 2026 - 0.18 MW; 2027 - 0.18 MW
Northern Tablelands	Burren Junction	BJN8B3 M37 Yarran	Reliability	PPF - BJN8B3 Pilliga Road - 5.2km HV Reconnector	\$ 256,469	Jun-23	0.54 MVA	2023 - 2.17 MVA; 2024 - 2.17 MVA; 2025 - 2.17 MVA; 2026 - 2.17 MVA; 2027 - 2.17 MVA	2023 - 0.53 MW; 2024 - 0.53 MW; 2025 - 0.54 MW; 2026 - 0.54 MW; 2027 - 0.54 MW
Northern Tablelands	Coonabarabran	CBB8B1 Tambar Springs	Asset Condition	Purlewaugh Coonabarabran Rd 14280 8025 HV Conductor End of Life	\$ 202,679	Jul-24	0.5 MVA	2023 - 2.02 MVA; 2024 - 2.02 MVA; 2025 - 2.02 MVA; 2026 - 2.02 MVA; 2027 - 2.02 MVA	2023 - 0.45 MW; 2024 - 0.45 MW; 2025 - 0.45 MW; 2026 - 0.45 MW; 2027 - 0.45 MW
Northern Tablelands	Tamworth East	ETH3B10 Ebsworth/Bridge	Asset Condition	Tamworth Shopping World 18-4266 NEBB HV Switchgear End of Life	\$ 368,000	Jul-24	1.1 MVA	2023 - 1.5 MVA; 2024 - 1.5 MVA; 2025 - 1.5 MVA; 2026 - 1.5 MVA; 2027 - 1.5 MVA	2023 - 0.96 MW; 2024 - 0.96 MW; 2025 - 0.96 MW; 2026 - 0.96 MW; 2027 - 0.96 MW
Northern Tablelands	Kootingal	KTL3B2 Moonbi	Asset Condition	Moonbi New England Hwy Segment 18-R12326 HV Conductor End of Life	\$ 495,248	Jul-23	1.07 MVA	2023 - 1.22 MVA; 2024 - 1.22 MVA; 2025 - 1.22 MVA; 2026 - 1.22 MVA; 2027 - 1.22 MVA	2023 - 1.03 MW; 2024 - 1.03 MW; 2025 - 1.03 MW; 2026 - 1.03 MW; 2027 - 1.03 MW
Northern Tablelands	Narrabri	NBI8B10 M16 Mount Dowe	Reliability	Replace ground mount TX 75-160005 Mt Dowe Kaputar with padsub	\$ 228,068	Jun-23	0 MVA	2023 - 3.09 MVA; 2024 - 3.09 MVA; 2025 - 3.09 MVA; 2026 - 3.09 MVA; 2027 - 3.09 MVA	2023 - 0.61 MW; 2024 - 0.61 MW; 2025 - 0.61 MW; 2026 - 0.61 MW; 2027 - 0.61 MW
Northern Tablelands	Narrabri	NBI8B7 M6 Wee Waa	Voltage	Narrabri 75-981637 and 75-18000 HV Backfeed	\$ 343,973	Jun-23	0 MVA	2023 - 2.44 MVA; 2024 - 2.44 MVA; 2025 - 2.44 MVA; 2026 - 2.44 MVA; 2027 - 2.44 MVA	2023 - 1.72 MW; 2024 - 1.72 MW; 2025 - 1.72 MW; 2026 - 1.71 MW; 2027 - 1.71 MW
Northern Tablelands	Nundle	NDL3B2 Woolomin	Asset Condition	Woolomin Nundle Rd 232776 HV Conductor End of Life	\$ 343,018	Jul-23	1.47 MVA	2023 - 2 MVA; 2024 - 2 MVA; 2025 - 2 MVA; 2026 - 2 MVA; 2027 - 2 MVA	2023 - 1.32 MW; 2024 - 1.32 MW; 2025 - 1.32 MW; 2026 - 1.32 MW; 2027 - 1.32 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>Northern Tablelands</u>	Tamworth South	STH3B11 Robert St	Asset Condition	Tamworth Links Ave 18-15760 LV Consac End of Life	\$ 249,411	Jul-23	0.04 MVA	2023 - 0.17 MVA; 2024 - 0.17 MVA; 2025 - 0.17 MVA; 2026 - 0.17 MVA; 2027 - 0.17 MVA	2023 - 0.04 MW; 2024 - 0.04 MW; 2025 - 0.04 MW; 2026 - 0.04 MW; 2027 - 0.04 MW
<u>Northern Tablelands</u>	Werris Creek	WCK516 Dewhurst/Gordon	Asset Condition	Werris Creek Dewhurst Street 213917 HV Conductor End of Life	\$ 225,595	Jul-23	2.53 MVA	2023 - 1.56 MVA; 2024 - 1.56 MVA; 2025 - 1.56 MVA; 2026 - 1.56 MVA; 2027 - 1.56 MVA	2023 - 2.28 MW; 2024 - 2.28 MW; 2025 - 2.28 MW; 2026 - 2.28 MW; 2027 - 2.28 MW
<u>Northern Tablelands</u>	Walcha South 22/11kV	WLS3B1 Walcha East	Asset Condition	Walcha Apsley Derby Hill Street HV Conductor End of Life	\$ 210,947	Jul-24	1.42 MVA	2023 - 2.2 MVA; 2024 - 2.2 MVA; 2025 - 2.2 MVA; 2026 - 2.2 MVA; 2027 - 2.2 MVA	2023 - 1.41 MW; 2024 - 1.46 MW; 2025 - 1.5 MW; 2026 - 1.55 MW; 2027 - 1.6 MW
<u>Ranges</u>	Galloway St	GLS3B1 Gara	Asset Condition	10.8km 11kV Copper reconductor	\$ 462,850	Mar-24	0.12 MVA	2023 - 1.16 MVA; 2024 - 1.16 MVA; 2025 - 1.16 MVA; 2026 - 1.16 MVA; 2027 - 1.16 MVA	2023 - 0.58 MW; 2024 - 0.59 MW; 2025 - 0.6 MW; 2026 - 0.61 MW; 2027 - 0.62 MW
<u>Ranges</u>	Lismore South	SLI3B8 Carrington St Nth	Asset Condition	Lismore Winterton and Alexandra Pde OH - Reconduct HV	\$ 322,226	Jan-24	4.66 MVA	2023 - 2.59 MVA; 2024 - 2.59 MVA; 2025 - 2.59 MVA; 2026 - 2.59 MVA; 2027 - 2.59 MVA	2023 - 4.24 MW; 2024 - 4.25 MW; 2025 - 4.24 MW; 2026 - 4.25 MW; 2027 - 4.27 MW
<u>Ranges</u>	Madgwick Dr	UNI3B2 Tilbuster/Puddledock	Asset Condition	Armidale Toms Gully road HV Reconductor PPF	\$ 281,616	Feb-24	0.15 MVA	2023 - 1.05 MVA; 2024 - 1.05 MVA; 2025 - 1.05 MVA; 2026 - 1.05 MVA; 2027 - 1.05 MVA	2023 - 0.89 MW; 2024 - 0.9 MW; 2025 - 0.91 MW; 2026 - 0.92 MW; 2027 - 0.93 MW
<u>Riverina Slopes</u>	Adelong	ADE22 Rural West	Asset Condition	Replace failing copper with 7/3.00AAAC	\$ 349,725	Jul-23	0 MVA	2023 - 0.99 MVA; 2024 - 0.99 MVA; 2025 - 0.99 MVA; 2026 - 0.99 MVA; 2027 - 0.99 MVA	2023 - 0.08 MW; 2024 - 0.08 MW; 2025 - 0.08 MW; 2026 - 0.08 MW; 2027 - 0.08 MW
<u>Riverina Slopes</u>	Ashmunt	ASM3B4 Fernleigh Rd West	Asset Condition	Replace LV UG CONSAC cable	\$ 247,000	Jul-23	0.3 MVA	2023 - 0.3 MVA; 2024 - 0.3 MVA; 2025 - 0.3 MVA; 2026 - 0.3 MVA; 2027 - 0.3 MVA	2023 - 0.29 MW; 2024 - 0.29 MW; 2025 - 0.29 MW; 2026 - 0.29 MW; 2027 - 0.29 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>Riverina Slopes</u>	Ashmont	ASM389 Ashmont Sth	Asset Condition	Replace LV UG CONSAC cable	\$ 263,000	Jan-24	0.2 MVA	2023 - 0.2 MVA; 2024 - 0.2 MVA; 2025 - 0.2 MVA; 2026 - 0.2 MVA; 2027 - 0.2 MVA	2023 - 0.1 MW; 2024 - 0.1 MW; 2025 - 0.1 MW; 2026 - 0.1 MW; 2027 - 0.1 MW
<u>Riverina Slopes</u>	Cowra	COW62 Cowra Town Centre	Voltage	Replace 270m of copper LV conductor with 150ABC between poles 126 076 and CE291914 in the vicinity of Bartlett Ave. Replace 67m of copper LV conductor with 95ABC between poles CE291914 and pole 116 076 in the vicinity of Bartlett Ave and Kendall St	\$ 74,134	Jul-23	3.16 MVA	2023 - 2.76 MVA; 2024 - 2.76 MVA; 2025 - 2.76 MVA; 2026 - 2.76 MVA; 2027 - 2.76 MVA	2023 - 0.1 MW; 2024 - 0.1 MW; 2025 - 0.1 MW; 2026 - 0.1 MW; 2027 - 0.1 MW
<u>Riverina Slopes</u>	Hammond Ave	HAM3B1 Copland St	Asset Condition	Convert site to pole mount transformer	\$ 117,000	Jul-23	0.5 MVA	2023 - 0.5 MVA; 2024 - 0.5 MVA; 2025 - 0.5 MVA; 2026 - 0.5 MVA; 2027 - 0.5 MVA	2023 - 0.47 MW; 2024 - 0.47 MW; 2025 - 0.47 MW; 2026 - 0.47 MW; 2027 - 0.47 MW
<u>Riverina Slopes</u>	Hammond Ave	HAM3B5 Edward St	Asset Condition	Refurbishment of chamber substation	\$ 150,000	Jul-23	0.8 MVA	2023 - 0.8 MVA; 2024 - 0.8 MVA; 2025 - 0.8 MVA; 2026 - 0.8 MVA; 2027 - 0.8 MVA	2023 - 0.75 MW; 2024 - 0.75 MW; 2025 - 0.75 MW; 2026 - 0.75 MW; 2027 - 0.75 MW
<u>Riverina Slopes</u>	Tumbarumba	TUM32 Tumbarumba Town	Safety	Underground O/H lines in depot area for safety reasons	\$ 336,876	Jul-23	0 MVA	2023 - 2.32 MVA; 2024 - 2.32 MVA; 2025 - 2.32 MVA; 2026 - 2.32 MVA; 2027 - 2.32 MVA	2023 - 1.05 MW; 2024 - 1.05 MW; 2025 - 1.05 MW; 2026 - 1.05 MW; 2027 - 1.05 MW
<u>South Eastern</u>	Brisbane Grove	BRI Braidwood	Asset Condition	Replace 7.85km of failing copper on Durran Durra Line Braidwood	\$ 325,980	Jul-23	0 MVA	2023 - 1.77 MVA; 2024 - 1.77 MVA; 2025 - 1.77 MVA; 2026 - 1.77 MVA; 2027 - 1.77 MVA	2023 - 0.11 MW; 2024 - 0.11 MW; 2025 - 0.11 MW; 2026 - 0.11 MW; 2027 - 0.11 MW
<u>South Eastern</u>	Clinton Street	CST5352 Auburn St East	Asset Condition	Replace pad sub	\$ 144,000	Jul-23	0 MVA	2023 - 6.05 MVA; 2024 - 6.05 MVA; 2025 - 6.05 MVA; 2026 - 6.05 MVA; 2027 - 6.05 MVA	2023 - 0.75 MW; 2024 - 0.75 MW; 2025 - 0.75 MW; 2026 - 0.75 MW; 2027 - 0.75 MW
<u>South Eastern</u>	Goulburn North	GBN6212 Towrang	Asset Condition	Replace failing Quince conductor add 3rd phase and install 2 reclosers Towrang feeder	\$ 289,770	Jul-23	0 MVA	2023 - 1.72 MVA; 2024 - 1.72 MVA; 2025 - 1.72 MVA; 2026 - 1.72 MVA; 2027 - 1.72 MVA	2023 - 0.25 MW; 2024 - 0.25 MW; 2025 - 0.25 MW; 2026 - 0.25 MW; 2027 - 0.25 MW
<u>South Eastern</u>	Goulburn 132/33kV	GOU42 Goulburn No.4	Reliability	Install recloser to automate reclose function as 33kV fuses 21-F1386 are spuriously blowing from storm activity	\$ 59,670	Jul-23	0 MVA	2023 - 7.89 MVA; 2024 - 7.89 MVA; 2025 - 7.89 MVA; 2026 - 7.89 MVA; 2027 - 7.89 MVA	2023 - 1 MW; 2024 - 1 MW; 2025 - 1 MW; 2026 - 1 MW; 2027 - 1 MW

SUMMARY OF IDENTIFIED DISTRIBUTION FEEDER LIMITATIONS									
Operations Area	Zone Substation Name	Feeder	Primary Driver	Preferred Network Solution	Estimated Capital Cost	Proposed Timing	Demand Reduction Required for 1 Year Deferral	Segment Asset Rating	Load At Risk
<u>South Eastern</u>	Jindabyne 11kV	JIN82 Waste Point	Reliability	Replace failing Quince with Raisin ACSR	\$ 222,515	Jul-23	0 MVA	2023 - 1.11 MVA; 2024 - 1.11 MVA; 2025 - 1.11 MVA; 2026 - 1.11 MVA; 2027 - 1.11 MVA	2023 - 0.12 MW; 2024 - 0.12 MW; 2025 - 0.12 MW; 2026 - 0.12 MW; 2027 - 0.12 MW
<u>South Eastern</u>	Sutton	SUT3B2 Gundaroo	Voltage	Reconductor 800 metres of single phase 3/2.00 SCGZ conductor from pole CE217297 to sub 33-3026 Lute Street Gundaroo with 3 phase 7/3.00 AAAC to improve power quality and allow for future development	\$ 61,019	Jul-24	0.1 MVA	2023 - 0.86 MVA; 2024 - 0.86 MVA; 2025 - 0.86 MVA; 2026 - 0.86 MVA; 2027 - 0.86 MVA	2023 - 0.2 MW; 2024 - 0.2 MW; 2025 - 0.2 MW; 2026 - 0.2 MW; 2027 - 0.2 MW

3.4 Network Asset Retirements and De-ratings – Sub-transmission

3.4.1 Casino to Mallanganee 33kV Feeder

Asset Description

The 8401 sub-transmission feeder from Casino to Mallanganee consists of 15km and 21km sections of radial 7/.080 copper conductor, supplying around 2,000 customers in total between Mallanganee, Bonalbo and Urbenville zone substations.

The feeder was constructed in 1950, consisting of 239 spans with single pole, predominantly delta pin pole top construction and 7/.080 copper conductor. It has 11kV underslung for the entire length, except for a short section near Casino, the underslung 11kV is also mostly copper conductor of same era. The average pole age is 37 years, with 80 of the 239 poles over 50 years old.

The feeder transverses from the relatively flat areas at Casino rising into the hills and into the Great Dividing Range near Mallanganee. Located in a small area of NSW that has the highest average lightning ground flash density, the feeder is susceptible to thunderstorms and lightning strikes, particularly in the higher area near Mallanganee. Having delta pin pole top construction, the feeder has no overhead earthwire protection, other than small sections (<1km) at the exit of Casino and entry to Mallanganee zone substations.

Assessment

The 67-year-old 7/.080 copper conductor on this feeder is reaching end of serviceable life and is subject to regular failure, resulting in poor reliability for customers and an increasing public safety risk.

Being in an area susceptible to lightning strikes, the conductor is struck excessively, producing fault currents that overheat the conductor, leading to annealing of the copper strands. The copper hardens over the long term and combined with pitting, strands begin to fracture and the conductor breaks.

The original design of the feeder has inherent problems. The spans lengths are relatively long in areas traversing hills. The chance of inter-circuit conductor clash is increased as conductor swings are exacerbated in the areas with longer spans, leading to further conductor failure.

The conductor can be joined with short sections of new conductor, splices and compression sleeves but over time the rate of failure increases exponentially as the conductor reaches end of life. The Casino – Mallanganee feeder has over 200 joints/splices.

Date of retirement

Replacement of an initial 15km section of copper conductor has been completed.
Replacement of the next 21km section of copper conductor is planned for 2024/25.

Changes since previous DAPR

The initial 15km section is now complete, and remaining conductor is still planned for 2024/25.

3.5 Network Asset Retirements and De-ratings – Zone Substation

Essential Energy continue to improve their asset management strategies and policies which support the capital investment process. This includes both augmentation and replacement driven projects. For replacement driven projects the risk of asset failure is monitored, as well as its impact on reliability, safety, and the environment. The planned timing of a retirement project could change from year to year as the value assessment of cost verse risk on all augmentation and replacement projects through all asset types are evaluated and compared regularly to produce an optimised capital investment program. The estimated timings are from the most recent optimisation.

3.5.1 Indoor Switchboard Replacement, Refurbishment and Conversion

Zone Substation Indoor Switchboards (Replacement, Refurbishment & Conversion)		
Asset Description and Location	Timing	Reason Identified
Beelbangera ZS Refurbishment / Replacement	Jun-23	ECONOMIC END OF LIFE, SAFETY
Cartwrights Hill 66/11kV ZS Switchboard Refurbishment/Replacement	Jun-25	ECONOMIC END OF LIFE, SAFETY
Cootamundra ZS Refurbishment / Replacement	Jun-24	ECONOMIC END OF LIFE, SAFETY
Forster Z/Sub 11kV Switchboard & 66kV CB's Refurbishment / Replacement	Jun-23	ECONOMIC END OF LIFE, SAFETY
Googong Dam ZS Refurbishment / Replacement	Jun-25	ECONOMIC END OF LIFE, SAFETY
Laurieton ZS Refurbishment / Replacement	Jun-25	ECONOMIC END OF LIFE, SAFETY
Narooma ZS Refurbishment / Replacement	Jun-26	ECONOMIC END OF LIFE, SAFETY
Owen St ZS Refurbishment / Replacement	Jun-26	ECONOMIC END OF LIFE, SAFETY
Perisher ZS Refurbishment / Replacement	Jun-25	ECONOMIC END OF LIFE, SAFETY
Temora ZS Refurbishment / Replacement	Jun-24	ECONOMIC END OF LIFE, SAFETY

3.5.2 Power Transformer Replacement

Zone Substation Power Transformer Replacement		
Asset Description and Location	Timing	Reason Identified
Burren Junction ZS Replace TX1	Jun-24	ECONOMIC END OF LIFE
Cartwrights Hill Z/Sub Replace TX1	Jun-25	ECONOMIC END OF LIFE
Gulgong ZS Replace TX1	Jun-25	ECONOMIC END OF LIFE
Guyra ZS Replace TX2	Jun-25	ECONOMIC END OF LIFE
Moulamein TX2 Replacement	Jun-25	ECONOMIC LIFE EXTENSION
Oura Z/Sub Replace TX4	Jun-25	ECONOMIC END OF LIFE

3.5.3 Circuit Breaker Replacement

Zone Substation Circuit Breaker Replacement		
Asset Description and Location	Timing	Reason Identified
Boggabri ZS - Replace 66kV and 11kV CB's	Jun-25	ECONOMIC END OF LIFE
Temora 132 - Replace six 66kV CB's and CT's	Jun-24	ECONOMIC END OF LIFE
Ulan Switching Station - Replace five CB's	Jun-23	ECONOMIC END OF LIFE
Wellington ZS - Replace three 66kV CB's	Jun-24	ECONOMIC END OF LIFE

3.5.4 Combined Asset Retirements and De-Ratings

Combined Asset Replacements			
Asset Description	Region	Timing	Reason Identified
Wooden Pole Staking and Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Wooden Pole Staking and Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Wooden Pole Staking and Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Wooden Pole Staking and Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Wooden Pole Staking and Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Concrete/Steel/Other Pole Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Concrete/Steel/Other Pole Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Concrete/Steel/Other Pole Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Concrete/Steel/Other Pole Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Concrete/Steel/Other Pole Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Pole Top Structure Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Pole Top Structure Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Pole Top Structure Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Pole Top Structure Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Pole Top Structure Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Overhead Conductor Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Overhead Conductor Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Overhead Conductor Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Overhead Conductor Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Overhead Conductor Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Underground Cable Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Underground Cable Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Underground Cable Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Underground Cable Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Underground Cable Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Service Line Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Service Line Replacement	All Regions	Jun-24	Asset Age, Asset Failure

Combined Asset Replacements			
Asset Description	Region	Timing	Reason Identified
Service Line Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Service Line Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Service Line Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Pole Mounted Transformer Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Pole Mounted Transformer Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Pole Mounted Transformer Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Pole Mounted Transformer Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Pole Mounted Transformer Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Kiosk/Chamber/Other Transformer Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Kiosk/Chamber/Other Transformer Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Kiosk/Chamber/Other Transformer Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Kiosk/Chamber/Other Transformer Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Kiosk/Chamber/Other Transformer Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Network Switchgear Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Network Switchgear Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Network Switchgear Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Network Switchgear Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Network Switchgear Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Public Lighting Replacement	All Regions	Jun-23	Asset Age, Asset Failure
Public Lighting Replacement	All Regions	Jun-24	Asset Age, Asset Failure
Public Lighting Replacement	All Regions	Jun-25	Asset Age, Asset Failure
Public Lighting Replacement	All Regions	Jun-26	Asset Age, Asset Failure
Public Lighting Replacement	All Regions	Jun-27	Asset Age, Asset Failure
SCADA, Network Control and Protection Systems Replacement	All Regions	Jun-23	Asset Age, Asset Failure
SCADA, Network Control and Protection Systems Replacement	All Regions	Jun-24	Asset Age, Asset Failure

Combined Asset Replacements			
Asset Description	Region	Timing	Reason Identified
SCADA, Network Control and Protection Systems Replacement	All Regions	Jun-25	Asset Age, Asset Failure
SCADA, Network Control and Protection Systems Replacement	All Regions	Jun-26	Asset Age, Asset Failure
SCADA, Network Control and Protection Systems Replacement	All Regions	Jun-27	Asset Age, Asset Failure
Streetlight Control Wire Removal	All Regions	Jun-23	Asset Age, Safety
Streetlight Control Wire Removal	All Regions	Jun-24	Asset Age, Safety
Streetlight Control Wire Removal	All Regions	Jun-25	Asset Age, Safety
Streetlight Control Wire Removal	All Regions	Jun-26	Asset Age, Safety
Streetlight Control Wire Removal	All Regions	Jun-27	Asset Age, Safety

4. NETWORK INVESTMENTS

4.1 Regulatory Test / RIT-Ds Completed or in Progress

The selected option for the rectification of Master Subtractive Metering sites listed in the 2021 DAPR is currently in progress.

Regulatory Test / RIT-Ds Completed in the Preceding Year or In Progress									
Title	Status / Stage	System Limitation	Potential Credible Solutions	Net Economic Benefit (\$M)	Preferred Option			Network User Impacts	
					Capital Cost (\$M)	Timing	Commissioning Estimated Date	On Connection Charges	On DUOS Charges
Rectification of Master Subtractive Metering sites	In progress	Complex premises arrangements with one master meter servicing multiple NMIs are not consistent with the requirements of National Electricity Rules	Arrange for the rectification of all MSM sites before end of FY29 internal and externally resourced (Preferred Solution)	-31.54	19.76	FY21 to FY29	FY29	Nil	Nil

4.2 Potential RIT-Ds for Identified System Limitations

POTENTIAL RIT-Ds FOR IDENTIFIED SYSTEM LIMITATIONS			
Project Name	Project Driver	Estimated Cost	RIT-D Requirement / Commencement
Bonny Hills 33/11kV ZS	Asset condition , safety and environmental risk	\$8M	Non-Network Screening Report #
Pipers Gap 33/11kV ZS	Asset condition and safety risk	\$12M	Non-Network Screening Report #
Sovereign Hills 33/11kV ZS	Growth in demand, residential and commercial developments	\$8M	RIT-D March 2023

A Non-Network Screening Report will be published, noting non-network solutions cannot adequately address the safety, asset condition and environmental issues. Consequently, a RIT-D report will not be prepared in accordance with clause 5.17.4(c) of the National Electricity Rules.

4.3 Urgent and Unforeseen Investments

The Feb 2022 Northern NSW floods inundated South Lismore 66/11kV zone substation, causing significant damage to Essential Energy assets. Emergency equipment was installed, and temporary modifications were made to the zone substation configuration which enabled supply to be restored to customers. This arrangement is not suitable for long-term operation of the zone substation. The preferred solution for the long-term is to relocate the zone substation to higher ground, within Essential Energy's Lismore 132/66kV transmission substation.

A review is being undertaken for this investment to be part of AER 2021/22 Lismore Flood Cost Pass Through Application.

5. JOINT PLANNING

Joint Planning is a requirement under Rule 5.14 of the NER, which requires Essential Energy to carry out Joint Planning with each Network Service Provider (NSP) to which its networks are connected. Consequently, Essential Energy conducts Joint Planning activities with TNSPs – Transgrid and Powerlink Queensland. At a DNSP level, it conducts such activities with Energex and Ergon Energy (of parent company Energy Queensland formed as of 1 July 2016), Ausgrid, Endeavour Energy, Evoenergy (formerly ActewAGL) and Powercor Australia.

The frequency, process and methodology of such Joint Planning depends on the timing of emerging network constraints due to growth, reliability and refurbishment needs, as well as other external drivers such as third-party connection requests to service new or augmented major loads and generators.

Joint Planning aims to identify the most efficient network or non-network option to address the need in a prudent manner, regardless of ownership, jurisdiction, or boundary.

In general, the process and methodology establishes a formal Joint Planning committee between the relevant parties (Essential Energy and the NSP or in some cases multiple NSPs) which, depending upon the emerging limitation(s), severity and impact, will then meet to jointly confirm, quantify, review, recommend and resolve the matter(s).

This is undertaken using agreed technical, unit cost, fiscal, risk and sensitivity assessment assumptions and criterion to compare and evaluate the credible non-network and network alternatives in order to select, plan and deliver the most prudent investment(s) in accordance with NER requirements and objectives.

In the case of shared investments over a combined total cost threshold of \$6M, regulatory consultation documentation and notifications are prepared and published jointly in accordance with the NER process requirements.

For investments below this threshold value, the appropriate investment case documentation is shared and held by the joint parties. In both instances, where necessary, a Joint Planning Report (JPR) is executed to define the high-level responsibilities of all parties in delivering, funding and owning the investment or parts thereof.

5.1 Results of Joint Planning with the TNSP Transgrid

5.1.1 Summary of the Process and Methodology

An existing Joint Planning committee, made up of network planning staff from Essential Energy and Transgrid, met regularly (approximately every quarter) throughout the past year. A Joint Planning Charter, detailing a formally structured approach and guiding principles, sets the basis. Issues and outcomes were minuted with actions, and where necessary, issues were referred to an overseeing Joint Executive Steering Committee.

Transgrid has a Transmission Reliability Standard (enforced from 1 July 2018), and as an ongoing consequence Transgrid and Essential Energy have consulted with each other via Joint Planning, and where cost effective, are initiating works to reduce expected unserved energy supplied from Transgrid Bulk Supply Points.

5.1.2 Investments Jointly Planned

Several matters have required continued Joint Planning collaboration with Transgrid throughout 2022:

Joint Planning between Essential Energy and Transgrid regarding the apparent and emerging 132kV network constraints in the Orange, Parkes/Forbes, Beryl/Wellington and Gunnedah/Narrabri areas of NSW.

This is presently ongoing due to the uncertainty of spot load developments and several small to large embedded generation proposals.

Due to the recent renewable generation developments in the Far West of NSW, the fault level at the Transgrid Broken Hill 220/22kV substation has substantially increased and will continue to increase with planned network developments. Transgrid is currently investigating if the existing 220kV and 22kV equipment at its Broken Hill substation is suitable for the expected higher fault levels together with associated secondary systems renewal. This

renewal will also allow for the provision of an additional 22kV feeder bay for Essential Energy to cater for growth and customer supply reliability improvement.

Essential Energy and Transgrid have continued with Joint Planning delivery of the recommended option to re-instate supply to Cabramurra, Selwyn Ski Fields and Selwyn communication tower customers following the early January 2020 bushfires which destroyed large sections of the 33kV powerline from Providence Portal sourced from the Transgrid Cooma substation.

This involves the establishment of a 330/11kV bulk supply point at the Transgrid Upper Tumut Switching Station and a new single 11kV supply to support the Cabramurra, Selwyn Ski Fields, and Selwyn communication tower customer load. Scheduled commissioning has been postponed due mainly to abnormally adverse weather conditions and is re-scheduled for commissioning before March 2023.

There has also been continued ongoing Joint Planning collaboration with Transgrid regarding the provision of increased supply capacity from both the Transgrid Queanbeyan and Williamsdale substations to cater for proposed new and emerging loads in the South Jerrabomberra area of the Essential Energy footprint.

5.1.3 Additional Information

Additional detailed information regarding the above considerations may be obtained from the Essential Energy and Transgrid websites, and as published in the preceding and latest Transgrid Transmission Annual Planning Reports.

5.2 Results of Joint Planning with the TNSP Powerlink

5.2.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Powerlink Queensland as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities. The Joint Planning representatives from Powerlink and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

5.2.2 Investments Jointly Planned

In 2022, there has been ongoing Joint Planning coordination regarding the impacts and requirements for the Powerlink upgrade of secondary systems at Mudgeeraba substation and the replacement of the Directlink related ECS (Emergency Control Scheme). These works were completed in the latter half of 2022.

5.2.3 Additional Information

Nil.

5.3 Results of Joint Planning with the DNSP Energex

5.3.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Energex as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities.

The Joint Planning representatives from Energex and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

In 2022, there has been no material need to conduct formal Joint Planning with Energex. This is mainly due to the past and sustained decline in peak demand forecasts and the fact no limitation on the interconnecting sub-transmission and 11kV distribution network are imminent. Joint Planning has therefore been limited to a few telephone/email discussions between the respective network planning and customer connections teams.

5.3.2 Investments Jointly Planned

Nil.

5.3.3 Additional Information

Nil.

5.4 Results of Joint Planning with the DNSP Ergon

5.4.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Ergon as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

In 2022 there has been continued Joint Planning between Essential Energy and Ergon regarding the provision of both; (i) limited bi-directional emergency backup supply and, (ii) limited planned backup supply via a 33kV Open-Point at Mungindi, not far from the Essential Energy Mungindi 66/33/22kV zone substation. A staged implementation is planned, and now due to changes in prioritisation, is likely to be completed by late 2023/24.

5.4.2 Investments Jointly Planned

Limited bi-directional backup supply via an existing 33kV Open-Point near Mungindi. This will be facilitated by protection upgrades on the Ergon network including that at the Ergon St George substation, the replacement of the 33kV Open-Point switch, new 33kV pole-mounted cross-border metering, and the end-of-life replacement including reconfiguration of substation equipment at the Essential Energy Mungindi substation fed from Moree at 66kV.

5.4.3 Additional Information

Nil.

5.5 Results of Joint Planning with the DNSP Ausgrid

5.5.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Ausgrid as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities. The Joint Planning representatives from Ausgrid and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

In 2022, there has been no material need to conduct formal Joint Planning with Ausgrid. This is mainly due to follow-up meeting actions from 2021, to review and ascertain the adequacy of the interconnecting sub-transmission and 11kV distribution networks, including an increase in the Essential Energy load supported from the Ausgrid Brandy Hill substation 11kV network. Joint Planning has therefore been limited to a few telephone/email discussions between the respective network planning teams.

5.5.2 Investments Jointly Planned

Nil.

5.5.3 Additional Information

Nil.

5.6 Results of Joint Planning with the DNSP Endeavour Energy

5.6.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Endeavour Energy as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities. The Joint Planning representatives from Endeavour Energy and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

During 2022, there has been no material need to conduct formal Joint Planning with Endeavour Energy. Joint Planning has been limited to a few telephone/email discussions between the respective network planning and customer connections teams.

5.6.2 Investments Jointly Planned

Nil.

5.6.3 Additional Information

Nil.

5.7 Results of Joint Planning with the DNSP Evoenergy

5.7.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Evoenergy as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required, based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities. The Joint Planning representatives from Evoenergy and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

During 2022, there has been no material need to conduct formal Joint Planning with Evoenergy. Joint Planning has been limited to a few telephone/email discussions between the respective network planning and customer connections teams.

5.7.2 Investments Jointly Planned

Nil.

5.7.3 Additional Information

Nil.

5.8 Results of Joint Planning with the DNSP Powercor Australia

5.8.1 Summary of the Process and Methodology

For the purpose of effective network planning, Essential Energy has collaborated in regular Joint Planning with Powercor Australia as part of an established continual process. Necessary collaboration regarding network matters such as emerging constraints and planned developments have and are undertaken regularly, as required based on project need.

This is facilitated through face-to-face meetings or videoconferencing between Joint Planning representatives from both organisations. These interactions have formal agendas and minuted outcomes with assigned responsibilities. The Joint Planning representatives from Powercor and Essential Energy are from the respective Joint Planning teams and may from time-to-time consist of representatives from specialist technical teams outside of network planning.

In 2022, there has been no material need to conduct formal Joint Planning meetings with Powercor Australia. This is mainly due to the fact that no limitations on the interconnecting 66kV and 22kV networks are imminent. Joint Planning has therefore been limited to a few telephone/email discussions between the respective network planning, system operations and customer connection teams.

5.8.2 Investments Jointly Planned

Nil.

5.8.3 Additional Information

Nil.

6. NETWORK PERFORMANCE

6.1 Reliability Performance

Reporting is in accordance with the excluded interruption conditions of the STPIS, which include the removal of days where the distribution network exceeds the defined major event day boundary. The reliability measures used are SAIDI, average minutes without supply per customer, and SAIFI, average number of interruptions experienced per customer. Performance is monitored at distribution feeder level for unplanned interruptions.

Distribution feeders are categorised as Urban, Short Rural or Long Rural, based on feeder length and load density. Essential Energy's distribution network consists of 280 Urban Feeders, 942 Short Rural Feeders and 244 Long Rural Feeders, with over 64 per cent of customers on Short Rural Feeders.

An audit is conducted over this information as part of the Annual Reliability and Performance Licence Conditions Audit and the Quarterly report to IPART on compliance with the Reliability and Performance Licence Conditions.

6.1.1 Reliability performance against Licence Condition standards

Reliability outcomes by feeder category for the 2021/22 financial year were within the standard from Licence Conditions across all categories. The normalised Network Availability for the 2021/22 financial year was 99.96%.

Table 5 – Reliability performance against the Standard 2021/22

Feeder Category	SAIDI (minutes)		SAIFI (no of interruptions)	
	Standard	Actual	Standard	Actual
Urban	125	66	1.80	0.81
Short Rural	300	200	3.00	1.60
Long Rural	700	498	4.50	2.72

6.1.2 Individual Feeder performance against Licence Condition standards

The performance objectives for organisational average performances by feeder category are not sufficient to identify when customers on a particular feeder experience unsatisfactory reliability performance. For this reason, SAIDI and SAIFI criteria (after 'excluded interruptions' are disregarded) act as a trigger for investigation and exception reporting purposes. The figures contained in the licence conditions are shown in Table 6.

Table 6 – Individual feeder standards specified in the Licence Conditions 2021/22

	Feeder Category		
	Urban	Short Rural	Long Rural
SAIDI	400	1,000	1,400
SAIFI	6	8	10

Performance outside this range results in the following actions:

- Immediate investigation of the causes for each feeder exceeding the individual feeder standards
- By the end of the quarter following the quarter in which the feeder first exceeded the individual feeder standard, complete an investigation report identifying the causes and action required to improve the performance
- Complete any operational actions identified in the investigation report by the end of the third quarter following the quarter in which the feeder first exceeded the standard. Remedial actions could include but are not limited

to installing or reconfiguring network protection devices, out of schedule asset inspections and out of schedule vegetation inspections

- Where the investigation report identifies actions, other than operational actions, that are required to improve the performance of a feeder to the individual feeder standards, an investment plan is developed. The investment plan includes an implementation timetable of required capital works. This timetable details the commencement of implementation by the end of the second quarter following the quarter in which the feeder first exceeded the individual feeder standards. Remedial actions could include but are not limited to reconductoring sections of line, segmenting the network with gas switch or installation of additional protection devices and installing Line Fault Indicators (LFI) to enable increased fault finding and restoration efficiency.

Table 7 – Individual Feeder Performance against the Standard 2021/22

Feeder Category	Urban	Short Rural	Long Rural
Feeders (Total Number each Type)	280	942	244
Feeders that Exceeded the Standard During the Year (Total Number)	9	37	28

Table 8 – Individual Customer Performance against the Standard 2021/22

Individual Customer Performance	2021/22
Instances where minutes interrupted exceeded the standard	1
Instances where number of interruptions exceeded the standard	0

6.2 Quality of Supply Performance

The Electricity Supply Standards adopted by Essential Energy are set out in the document *CEOP8026 Electricity Supply Standard*, in accordance with the *Code of Practice – Electricity Service Standards*. A copy of *CEOP8026* can be downloaded from <https://www.essentialenergy.com.au/>.

CEOP8026 also outlines Essential Energy's adoption of the Australian Standard AS 61000.3.100 – 2011 (Amendment No.1 -2016) and Australian Standard AS 60038 – 2012 *Standard Voltages*.

The main areas addressed include:

- Voltage fluctuations (LV) managed in accordance with Australian Standards AS/NZS 61000.3.3:2012, SA/SNZ TS IEC 61000.3.5:2013 and SA/SNZ TR IEC 61000.3.5:2013
- Switching transients (voltage waveform distortion) limited where possible to less than twice normal supply voltage
- Frequency variation and Essential Energy's role in notifying AEMO of any sustained fluctuations
- Voltage swells and voltage dips (sags) managed through best practice network improvement and augmentation (Recommended voltage swell and dip thresholds given in Australian Standard AS 61000.3.100 – 2011 (Amendment No.1 -2016))
- Steady state voltage differences between neutral and earth limited to less than 10 volts at the customer's point of supply
- Lightning strikes limited in their impact on supply where possible by adherence to industry best practice system design and maintenance principles
- Limitation of 'step and touch' voltage differentials managed in accordance with industry standards, namely ENA EG-0 Power System Earthing Guide – ENA DOC 025-2010

- Essential Energy's objective is to limit voltage unbalance to levels as required by the National Electricity Rules. This is generally 2% on the high voltage network and up to 6% on the LV network using 10min average values. This level may be exceeded occasionally in some rural areas. However, Voltage Unbalance allocations for new customer connections are managed through the latest Australian Standard for Voltage Unbalance (AS/NZS TR IEC 61000.3.13:2012 and ENA Guideline for Power Quality – Voltage Unbalance)
- Harmonic content of voltage and current waveforms managed in accordance with Australian Standards AS/NZS TR IEC 61000.3.6:2012. Harmonic emission allocation process for new customer connections are managed through the Australian Standard and ENA Guideline for Power Quality – Harmonics
- Voltage fluctuations, flicker, and rapid voltage changes in HV network are managed in accordance with AS/NZS TR IEC 61000.3.7:2012 Standard. Like the harmonics and unbalance, all the new HV customer connections and emissions allocations are managed through the latest Australian standard and the ENA Guideline for Power Quality – Flicker
- Mains signalling reliability set at a target of 99.5 per cent failsafe to ensure correct switching and metering functions.

Quality of supply is monitored through power quality enquiries received from customers and also through participation in the Power Quality Compliance Audit conducted by the University of Wollongong and a number of other distributors throughout Australia. This survey studies parameters such as steady state voltage, voltage total harmonic distortion (THD), voltage sags and voltage unbalance on three phase sites.

All valid complaints assessed as being network related, or issues identified via network monitoring are addressed to ensure the situation is rectified and maintained within standards.

Remedial actions could include but are not limited to adjusting tap settings on transformers, adjusting voltage regulation levels, installing additional or larger transformers, augmenting network capacity, repairing network faults and balancing network loads.

Table 9 – Completed Investigations from Network Complaints

Network Complaint Investigations Completed		2021/22	
Category	Nature of Complaint	Number	Number Valid
Voltage	Sustained over voltage	186	148
	Sustained under voltage	60	42
	Voltage fluctuations	111	51
	Voltage dips	56	29
	Voltage swell	5	4
	Switching transients	0	0
	N-E voltage difference	121	46
	Ground fault voltage	6	5
	Voltage unbalance	9	5
	Mains signalling voltages (Outside defined range)	1	0
	HV injection (HV/LV Intermix)	0	0
	Notching	0	0
	Invalid (225 confirmed invalid)		
Subtotal (Supply Voltage Complaints)		555	330

Table 10 – Completed Investigations from Network Complaints

Network Complaint Investigations Completed		2021/22	
Category	Nature of Complaint	Number	Number Valid
Current	Direct current	0	0
	Harmonic content	2	0
	Inter Harmonics	0	0
	Invalid (0 confirmed invalid)		
Subtotal (Supply Current Complaints)		2	0
Other Quality	Mains signalling reliability	1	0
	Noise & Interference	15	6
	Level of supply capacity	24	15
	Embedded Generation (Solar)	740	580
	Embedded Generation (Wind)	3	3
	Supply frequency	2	0
	Level of EMF	3	0
	Customer Equipment Failure	68	13
Subtotal (Other Quality of Supply Complaints)		856	617
Subtotal (All Quality of Supply Complaints)		1413	947
Reliability	No. of supply failures	28	9
	Duration of supply failures	4	1
	Outages Miscellaneous	49	12
	No. of <1 min. interruptions	24	8
	Invalid (76 confirmed invalid)		
Subtotal (Reliability of Supply)		105	29
Total Completed		1518	976
Other	Intelligent Network Communities	0	0
	Under Investigation (not validated)	0	0
Totals		1518	976

The total number of FY22 Network Complaints decreased by 6.4% compared to FY21 (1516 vs 1622). Embedded Generation Solar continued to be the leading complaint with a total of 740 complaints although pleasingly a decrease of 30% overall compared to last financial year.

The total number of Sustained overvoltage complaints increased by 4% compared to last FY, however customer equipment failure, number of supply failures and outages miscellaneous remained similar compared to last financial year.

6.3 Frequency Control and Protection Systems

There have been no operations of load shedding, inter-tripping or generator runback schemes on the EE network which have caused adverse outcomes. Neither does Essential Energy expect a cascading outage or major supply disruption to be caused by any of our protection system operation or interactions.

7. ASSET MANAGEMENT

7.1 Essential Energy's Asset Management Approach

7.1.1 Introduction

Essential Energy obtained AS ISO 55001:2014 certification on the 15th of January 2022 and is continuing to grow its asset management maturity underpinned with a commitment to enable a safe, resilient and reliable network service that meet the needs of its customers and stakeholders. Essential Energy is continually improving its asset management capabilities by keeping abreast of developments domestically and abroad, including review and maintenance of the asset management system.

7.1.2 The Asset Management System

The present format of Essential Energy's Asset Management System Framework includes:

- Asset Management Policy Statement – This document's the key asset management principles in which the Asset Management System (AMS) adheres to
- Strategic Asset Management Plan (SAMP) – Sets out high-level decision-making principles, with an associated set of criteria. It details the Asset Management Objectives, explains their relationship to the organisational objectives and the role of the Asset Management System in delivering these. It describes how our Asset Management Objectives are translated into network activities, projects and programs for delivery, through our Asset Management System
- Asset Management Objectives (AMO) – Defines the key outcomes that will be delivered to our customers through specific asset management activities and the Asset Management System. The Objectives provide direction to help ensure the network, systems and assets deliver what we need and are used to set targets and measures so performance can be tracked
- Network, Asset Class and System strategies – Form the Asset Management direction and perform Asset Lifecycle analysis in order for Essential Energy to understand the activities it must undertake to get the outcomes it needs from its assets in support of its asset management objectives. These strategies set direction for the business in establishing programs of work to manage the network Essential Energy is accountable for
- Asset Management Planning and Optimisation – Network investments are initiated, planned, developed, and optimised through the coordinated activities of several functions across the business including Planning, Network Design, Network Portfolio, Investment Optimisation and Network Delivery. Investment identification is influenced by the content of the above strategies; preferred investments are identified through application of a range of decision-making criteria and optimised within Essential Energy's Asset Investment Planning software. These investments, together with additional mandatory projects, programs and cyclic maintenance-related activities form our Network Portfolio which is approved, managed, and governed using well-established practices.
- Lifecycle Delivery – The Network Portfolio is delivered through the coordinated activities of the Network Portfolio, Network Delivery and Network Operations teams through the development of Works Programs and Packaging and Scheduling activities. It drives the outcomes at each stage of an asset's lifecycle, from analysis, to planning, operating and maintaining the asset, and eventually disposing of it
- Performance Monitoring – Essential Energy is a complex business and the design of how it monitors performance enables metrics to be placed in a logical way that supports the understanding of performance on assets (i.e. asset health), asset management performance (including financial and non-financial performance) and the asset management system (i.e. effectiveness of the outputs of the processes, procedures etc). Collectively, these support the understanding of meeting the asset management objectives
- Performance Evaluation and Improvements – Supporting how we performance monitor is performance management. It is used to identify and evaluate that whether performance is being met, management actions are identified and taken to improve performance, and closes the loop.

7.2 Network and Asset Strategies

The following sections detail the specifics of Essential Energy's network and asset lifecycle management strategies to provide an overview of the high-level direction used to manage network performance.

7.2.1 Distribution Growth Strategy

The purpose of this document is to provide input into Essential Energy's asset management functions and ensure the coordinated management of growth activities. The Strategy covers measuring, monitoring, optimising and augmenting capacity and supply quality across Essential Energy's distribution network.

The strategy was developed to:

- Instil a systematic and consistent approach to managing demand and load growth throughout our asset management functions
- Break down the Asset Management Objectives, as directed by the overarching Strategic Asset Management Plan (SAMP), into more specific Asset System and Class objectives and targets, which are to be used in the Asset Management Plans and Investment Cases
- Define the components that constitute distribution network peak demand and load growth, their impacts, and how these components need to be managed
- Support continued investment for network optimisation, augmentation, and growth management.

It includes investments that will increase our active monitoring capabilities for network load and demand growth and voltage performance, which will assist with system optimisation and maximise network utilisation. These investments will allow for the deferral, reduction, or cancellation of investments to cater for demand growth on some parts of the network.

7.2.2 Network Reliability Strategy

Essential Energy's Network Reliability Strategy⁵ provides direction to ensure compliance with NSW Reliability and Performance Licence Conditions for Electricity Distributors, the National Electricity Rules and Essential Energy's corporate objectives. The strategy defines the approach to achieving targets set for the duration and frequency of both planned and unplanned interruptions to network supply, considering the business objectives to maintain overall reliability, improve reliability to worst-served customers and ensure compliance with NSW Reliability and Performance Licence Conditions for Electricity Distributors.

This strategy sets the targets to meet customer, regulatory and other stakeholder expectations, and meet licence conditions through a comprehensive approach across all asset classes in addition to identifying actions to improve the future management of reliability.

Key components of the reliability strategy include short- and long-term views of:

- Unavailability and Frequency duration measures – SAIDI and SAIFI
- Outage response measures – CAIDI
- Maintenance of Material Non-Compliances against IPART Reliability Licence Standards and reporting Conditions
- Cumulative SAIDI on worst performing feeder segments
- Number of planned customer interruptions per annum

7.2.3 Network Power Quality Strategy

Essential Energy's Power Quality (PQ) strategy provides strategic direction for the business on asset management targets and initiatives to ensure that Power Quality obligations are met.

⁵ This strategy is independent of the Service Target Performance Incentive Scheme (STPIS) Strategy that details the organisations approach to maximising return from the Australian Energy Regulator's reliability targets and revenue model

The Network PQ Strategy works in conjunction with relevant network and asset class strategies, and will:

- Achieve and maintain compliance with Power Quality standards,
 - Achieve and maintain compliance with Power Quality standards including relevant regulations and policies, while ensuring appropriate value add commercial trade-off,
 - Assist with setting up the associated network configuration and organisational processes with adjacent network strategies and stakeholders for execution
- Maximise value from PQ issue resolution through increased visibility
 - Maximise the value from PQ issue resolution by assessing the risk and value trade-offs,
 - Ensure responses to PQ issues are provided appropriate prioritisation consistent with Essential Energy's value and risk framework.
- Improve customers PQ complaint resolution experience
 - Assist with improving the PQ issue response time frame by refining the workflow management tool/monitoring systems, organisational processes, and accountabilities by creating a complete end to end process to monitor and track PQ issue resolution times to ensure timely response to customer complaints.
 - Establish PQ resolution KPIs that align with corporate goals to ensure accountability during the resolution process.
 - Ensure responses to PQ issues are provided appropriate prioritisation consistent with Essential Energy's value and risk framework that will improve the customers PQ experience.

The elements of the overall Power Quality strategy are:

Reactive Measures

- Investigate received power quality complaints and customer feedback quickly and efficiently
- Verify that power quality problems are indeed network related and are outside the levels prescribed in Electricity Supply Standards
- Rectify any local or wider area problems in a timely, economic, and effective manner, including the use of alternate remediation solutions
- Consult with and keep customers advised during all steps of the investigation and rectification process.

Proactive Measures

- Migrate towards a more proactive power quality management approach through improved visibility of network power quality performance delivered by leveraging the rollout of network technology and monitoring equipment. This is supported by the power quality emissions allocations process for new customer connections to capture the background Power Quality measurement information which is based on methodologies given in ENA Guides for Power Quality by means of advanced modelling in SINCAL power system analysis software
- Plan and implement a gradual migration in the median distribution voltage to 230 volts, in line with Australian Standard AS 61000.3.100 – 2011 (Amendment No.1 – 2016), which will minimise overvoltage situations and provide 'headroom' for distributed generation
- Systematic modelling and management of HV feeder voltage profiles and performance
- Improved management of new and additional loads and embedded generator connections.

7.2.4 Network Safety Strategy

Essential Energy's Network Safety Strategy provides direction to manage the network safety risk of the electricity network so far as is reasonably practicable (SFAIRP). The strategy has been developed to guide decision making within a framework of corporate risk tolerance, customer expectations and legislative requirements.

The strategy covers the measurement, monitoring, management of network safety and is complemented by existing procedures that form Essential Energy's Electrical Network Safety Management System (ENSMS) and Risk Management Framework.

Safety has always been the top consideration for Essential Energy at all stages of the asset management lifecycle including planning, design, procurement, construction, commissioning, operation, maintenance and ultimately de-commissioning and disposal or recycling

This strategy aligns with obligations under legislative instruments to ensure that asset management activities adhere to the principle of managing network risk, So Far As Is Reasonably Practicable.

Key components of the safety strategy include:

- An uplift in organisational knowledge of SFAIRP principles and the Electricity Network Safety Management System (ENSMS)
- The development of a clear line of sight to corporate metrics and asset class strategies to embed the management of safety performance
- The application of investment tools within the asset class strategies that facilitate the management of asset safety risk within the corporate risk appetite
- Investigation of a mechanism to regularly obtain and quantify the value placed by customers on asset safety performance
- Development of a Formal Safety Assessment (FSA) control register to allow mapping of controls to responsible business units
- Improved detailed causal data for safety incidents through linkages to asset failure data.

7.2.5 Network Sustainability Strategy

Essential Energy's Sustainability Strategy provides visibility of sustainability objectives as they relate to network assets, and direction on how to achieve these objectives. This will enable Essential Energy to implement asset management plans that optimise social, environmental, and financial benefits to improve the quality of life of Essential Energy's stakeholders now and in the future.

The Strategy applies sustainability in a holistic sense and takes into consideration the environmental, social and financial impacts to Essential Energy's assets and network utilisation. This is achieved by considering the interests and well-being of customers and employees, environmental health, and resource availability

Key components of the sustainability strategy include consideration of:

- Minimise risk to the environment SFAIRP through the application of Environment Formal Safety Assessment
- Map and maintain compliance with obligations and regulatory requirements for sustainability risk
- Manage sustainability risk within the corporate risk appetite through;
 - Analysing sustainability risk and determining those that are material
 - Incorporating material sustainability risks in the Network Risk Register
 - Updating the Asset Risk Management Procedure to consider the identified sustainability risks
 - Incorporating the (material) sustainability factors in the Appraisal Value Framework.
- Improve network sustainability performance through maturing methodologies used to measure the impacts on sustainability and defining the right metrics and key performance indicators
- Minimise network whole of life cost by valuing sustainability impacts throughout the asset lifecycle including quantifying the NPV.

7.2.6 Asset Intervention & Retirement Strategy

Essential Energy's Asset Intervention and Retirement Strategy provides direction across the business and all network asset classes on asset end of life planning to ensure that network assets continue to meet the company's corporate and asset management objectives.

Strategic direction of the Strategy includes:

- requirement to follow a standardised set of criteria to identify when there is a need for intervention across the network. Need decision process includes.

- A change to an asset's required level of service,
 - A change to an asset's ability to meet an existing level of service, or
 - An alternative opportunity becoming available which provides a different least cost option.
 - Ability to forecast end of life (PoF, CoF maturity, service level requirement definition), and
 - Availability of economic data to assess cost to serve.
- required to consider a minimum set of intervention options when responding to an asset's predicted end of life, to ensure that the required level of service is maintained at the least cost to serve. The range and depth of credible options considered should be commensurate with the investment value, but at a minimum should include:
 - A base case, which looks at the cost of continuing business-as-usual
 - A network replace case (including both distribution and sub transmission options where applicable)
 - A non-network case which considers demand management, asset derating, standalone power systems, or similar solution

7.2.7 Network Bushfire Prevention Strategy

Essential Energy's bushfire and risk management strategy aims to prevent or minimise the impacts of fire ignition from electrical assets, so far as is reasonably practicable. The following strategic elements are those relating more specifically to bushfire prevention even though many others exist which may have an indirect relationship. Bushfire prevention strategies include:

- Identification of high bushfire risk zones to ensure planning, design, construction, operations, and maintenance activities are undertaken with an increased awareness of bushfire start risk
- Consideration of bushfire risk in network asset planning and design decisions
- Prioritisation of asset inspection⁶ and maintenance with a focus on high fire risk areas, helping to ensure fire start risks are identified and appropriately actioned
- The completion of vegetation management in the form of tree cutting and clearing to manage the risk of trees or vegetation coming into contact with live lines or equipment and igniting fires
- The provision of advice and information to owners of private lines to inform them of fire risks on their lines and to make recommendations on risk control actions. Where no action is taken to correct defects on private lines within the prescribed notice period in high bushfire risk areas, Essential Energy will undertake works to correct the defect on a "do and charge" basis
- The implementation of operational limitations⁷ on total fire ban days to minimise the risk of lines or equipment inadvertently starting a bushfire
- Perform line patrols before restoration on total fire ban days
- Analysis of fire starts proven to be caused by Essential Energy's network and completion of root cause analysis to identify improved control or prevention measures that can be instituted or developed.

7.2.8 Network Security Strategy

This strategy provides visibility of Essential's Energy's security objectives as they relate to the unauthorised access to network assets and provides direction on how to achieve these objectives. The Network Security Strategy addresses asset management and engineering's strategy for the prevention of unauthorised access to:

- Network assets
- Network operational technology
- Network communications systems

The strategy is primarily focused on preventing unauthorised access events that results in the possibility of harm or disruption of the network.

⁶ Asset inspection includes the use of LiDAR and pre-bushfire season annual fly over inspection of the network

⁷ Operational limitations of auto reclose operations on specific circuit breakers on total fire ban days.

Strategic direction targets include

- Prevent harm to the public or physical disruption to network assets as a result of unauthorised access.
 - Establish line of sight between the physical and cyber security frameworks and asset class strategies as outlined in the figure to the right. These frameworks specify the factors effecting the likelihood and controls for security incidents, where the Asset Class Strategies provide the consequences to ensure appropriate controls are implemented. These frameworks also govern the processes for reporting and ongoing assessment.
- Maintain compliance with network security obligations and regulatory requirements
 - Develop a clear line of sight between the compliance drivers of network security and the responsible business units. Incorporate responsibilities mapped between the Formal Safety Assessment Controls and the business units responsible for managing performance.

7.2.9 Network Asset Class Strategies

Essential Energy's Asset Class strategies seek to ensure that network assets continue to achieve service level obligations while optimising the lifecycle costs. They describe the assets within each class, contain a SWOT analysis and use Probability of Failure and Consequence of Failure models to define the level of risk the asset class presents. They use the AMOs and the strategic direction provided through the Network Strategies to set measures and targets at an asset level, provide strategic directions of their own across the lifecycle and present a cost, risk and performance profile over a 20-year period. Elements considered in these strategies include inspection, maintenance, refurbishment, replacement, and disposal.

Intervention within the strategies can be categorised as either:

- Time-based: requiring asset treatments based on set time intervals
- Condition-based: requiring asset treatments based on identified asset condition or health
- Risk-based: requiring asset treatments based on the risk of asset failure, including consideration of the likelihood and consequence(s) of failure based on observed risk factors, or
- Predictive: requiring asset treatments based on consideration of the outputs of predictive analytics, particularly relating to the likelihood of asset failure.

Strategies will identify the optimum timing for treatment, including whether this is preventative or corrective, based on an understanding of the risks and costs associated with alternative practicable options.

7.2.10 Asset Value, Risk Management and Network Optimisation

Essential Energy has adopted a risk-based approach to achieving performance objectives from network assets at optimum whole of life cost.

- Asset Risk Management is the overarching risk assessment framework. It provides a consistent approach for calculating risk value from understanding an asset's probability of failure and likelihood of consequence across Essential Energy's network assets. It also provides the approach for undertaking risk evaluation and identifying risk treatments
- Appraisal Value Framework is the framework for monetising different types and levels of consequence resulting from network asset failures. This supports the asset risk management procedure towards a monetised risk and value-based approach to asset management decision making
- Risk Informed Optimisation is the methodology used for optimising a portfolio of investment. Using a risk-informed approach, Essential Energy develops a prudent and efficient portfolio of expenditure which provides improved value within a reasonable financial constraint. Essential Energy will continue to refine the portfolio and optimisation process as improvements are made to data, systems and modelling.

7.3 Treatment of Distribution Losses

Distribution losses refer to the losses incurred in transporting energy across the distribution network. Of the total 2021/22 energy input into Essential Energy's widely spread network, 5.05 per cent was consumed in the form of network losses.

Essential Energy's investment decisions are guided primarily by the need to achieve the service level obligations at the optimum lifecycle cost. The value of network losses is used in comparing alternative network or non-network solutions, which either act to reduce the average current through the network or lower the resistance. Accordingly, Essential Energy's approach ensures that the value of network losses influences decision making with respect to:

- Any network planning and subsequent augmentation specifically the selection of voltage, conductor and transformers
- Network performance, operation and switching
- Asset maintenance and replacement decisions
- Procurement of equipment.

Network losses are considered in the investment development stage, as well as in the detailed planning and approval stages.

7.4 Asset Issues Impacting Identified System Limitations

Network limitations are identified in the preparation of long-term network strategies. These limitations are then subject to detailed planning studies which consider any related issues arising from individual asset management strategies which are likely to have a material impact on the studied network.

The detailed planning studies include an assessment of non-network alternatives, fault levels, voltage levels, quality of supply considerations, asset replacement, asset refurbishments and new connection applications.

Present Value analysis is used to align the constraint solutions with other network requirements and optimise the investment profile to achieve service level obligations at the lowest lifecycle cost.

7.5 Obtaining Further Information on the Asset Management Strategy and Methodology

Further information on Essential Energy's asset management approach is available by contacting:

Essential Energy
Joshua Thomas
PO Box 5730
Port Macquarie NSW 2444
Email: josh.thomas@essentialenergy.com.au

8. DEMAND MANAGEMENT

8.1 Demand Management Activities in the Preceding Year

Essential Energy's internal demand management procedures for 2021/22 complied with the obligations set out in the National Electricity Rules.

New and Ongoing Innovative Demand Management developments during 2021/22 included:

- Develop capability to leverage network battery storage technology to address network constraints whilst addressing network reliability requirements
- Trial use of Hydrogen storage enables Essential Energy to develop a SAPS solution with enough autonomy to remove the backup diesel generator and transition SAPS to a 100% renewable solution
- Provide Back-up generators to low reliability feeders to ensure security of supply
- To deliver the capability to deploy SAPS solutions according to a defined and agreed set of criteria in normal, degraded and emergency situations. The outcome is that we are confident we have identified all high 'cost to serve' customer sites and have a range of measures in place to deploy SAPS (or otherwise) at these locations
- Continue to improve data acquisition from existing load control network assets to create more dynamic load profiles or network elements

8.2 Plans for demand management and embedded generation

Essential Energy has several strategic objectives which aim to ensure positive outcomes for its customers now and in the future through proactive and efficient promotion, development and implementation of demand management and non-network alternatives. These objectives include:

- Enhancement of the business case to further enable demand management and non-network alternatives as a primary element of the planning process and as a broad-based strategy
- Efficient development and refinement of demand management and non-network alternatives based technical skills, experience, and solutions.

Throughout 2022/23 new innovative Demand Management developments include:

- Development of a network wide DER hosting capacity model to forecast, at a program level, export constraints and efficient cost to effectively increase the hosting capacity of the network where resulting in a positive market net benefit for customers.
- Leveraging smart meter data to improve network visibility. Essential Energy continues to explore access arrangements and cost compared to network side solutions with a range of smart meter data providers to build visibility across the network with a focus on the low voltage (LV) level to assist with planning and operating the network.

8.3 Issues arising from applications to connect embedded generation

Essential Energy's distribution network continues to experience an increasing number of isolated issues relating to voltage rise from embedded generation units, resulting in over voltage tripping of the inverters, and in some cases supplying customers with voltages above Australian Standard limits.

Issues may arise where the service, consumer mains and/or submains conductor is incorrectly sized, incorrectly identified, or the maximum system output is calculated based on an underestimated conductor length. There are also issues that revolve around voltage rise along the low voltage distribution network due to a high penetration of embedded generation within localised areas. This issue typically arises in overhead network areas consisting of original overhead network low voltage conductor.

Export limited inverters have allowed for the reduction in voltage rise issues at the customer's switchboard and provides greater equity in systems where multiple customers share a single transformer. The export limit allows customers to install the most economically sized systems while capping the amount that can be fed back into the network. The embedded generation installer often nominates an export limit during the initial application, and Essential Energy has suggested appropriate export limits depending on network limitations and the size of the installation.

As part of Essential Energy's commitment to improving network connection standards for the purpose of enhancing the solar PV hosting capacity of the network to drive higher utilisation of customer DER and the network, from September 2018 Essential Energy mandated Volt-Var and Volt-Watt power quality response modes in alignment with AS4777.2 for all new Solar PV and battery storage installations. The new requirement assists with managing network voltage in high DER uptake areas of the network, increases the DER hosting capacity of the network, whilst minimising inverter tripping from excessive voltage rise on the network through the activation of 'soft' limits.

Going forward, Essential Energy will continue to identify more efficient options to address the issue of large increases in low voltage network voltage 'swing' brought about by localised pockets of embedded generation, for the long-term interests of customers. Based on learning outcomes from recent trials, such new methods to facilitate the effective and efficient uptake of embedded generation include but not limited to; a shift from static to dynamic connection standards and cost reflective pricing to drive efficient use of the network.

Linked to the history of electricity distribution development within New South Wales, Essential Energy's network was planned, designed, and operated for peak load, due to such, reverse power flow for some areas of the high voltage network is resulting in abnormal asset operation, amplifying existing voltage rise issues and incorrect measurements from network monitoring equipment. Such emerging issues are driving changes to Essential Energy's Asset Management policies and procedures to ensure asset configuration and capability is compatible with reverse power flow conditions, in addition, voltage regulation practices across all levels of the network.

The integration of increasing numbers of embedded generators has required some minor changes to operational procedures. The use of Fameca FC3000 LV network identification equipment produces inconsistent results during times of reverse power flow, requiring local embedded generation to be temporarily disabled or use of the equipment outside of peak generation hours. When mobile diesel generation is used on LV street circuits during planned outages, solar installations resynchronise and supply real power only, requiring the mobile generation to supply much of the reactive power for the LV loads along with the small amount of remaining real power. This poor power factor or even reverse power can lead to tripping of the mobile generation. To prevent this, local embedded generation must be manually disabled during planned outages where temporary generators are used. The alternative of operating the generation outside the embedded generation anti islanding frequency range has not been adopted within Essential Energy.

There are a growing number of distribution substations experiencing high PV penetration, in extreme cases causing network protection to operate during maximum export. These areas are being investigated to verify network performance and to confirm PV installations are operating within their connection application limits to prevent these outages from occurring.

Network costs to address constraints linked to the uptake of DER across the network continues to increase each year. Noting such costs to enable greater export capacity is currently borne by all customers who are connected to the network, not just those who choose to export energy, with the majority of such costs recovered from non-export customers due to the current cost recovery mechanism based on energy consumed, Essential Energy is actively involved within industry and customer working groups to identify a fair and equitable network access and cost recovery process to guide the future uptake of DER for the long term interest of all customers.

Residential and small business installed solar capacity has seen constant growth as shown in Figure 5.

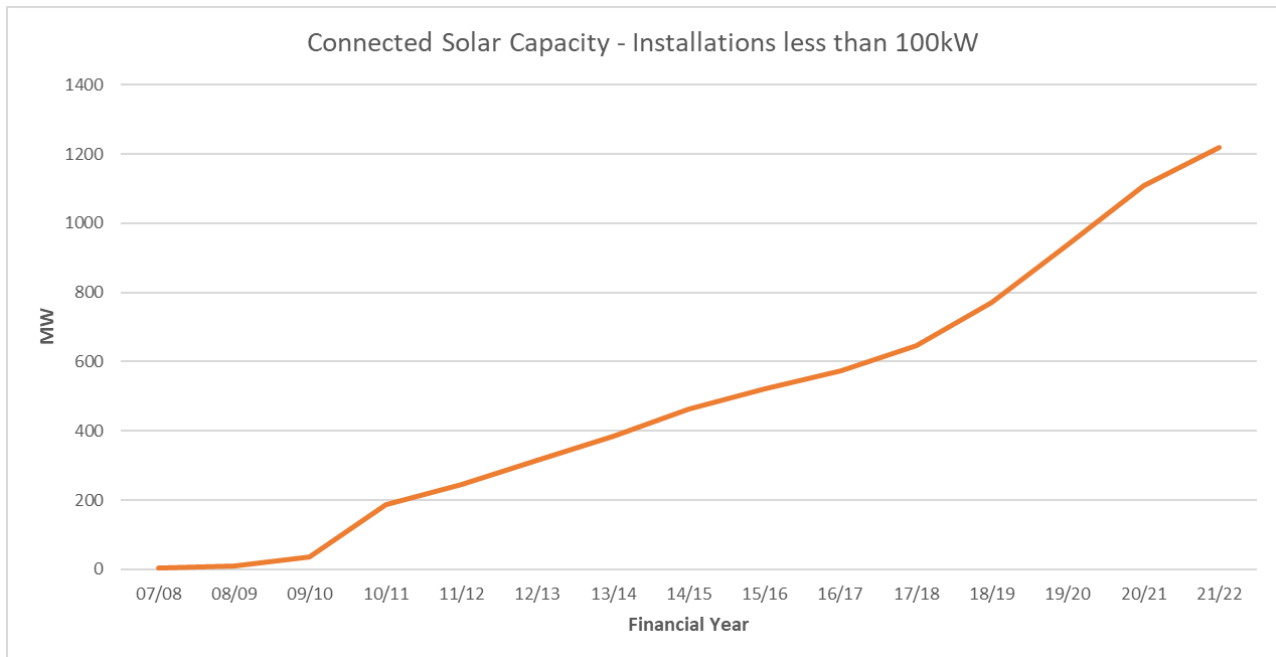


Figure 5 – Installed Solar Capacity, Excluding Large Scale Generation

8.4 Non-Network Solutions

8.4.1 Standalone Power Systems (SAPS)

With the NSW Government adopting the AEMC National SAPS framework, Essential Energy is now to develop and implement SAPS investments from FY23 and beyond. This will commence with the conversion of 2 trial SAPS to permanent installations and another 2 new SAPS investments. All four projects are for single customer sites, with demand less than 15kw each.

Essential Energy's SAPS will be deployed in compliance with the Ringfencing Guideline Version 3 released in November 2021, as such Essential Energy will provide the generation services as the SAPS resource provider under the category 1 classification. However, with the AEMO metrology process not expected to be implemented until late 2023, the first deployments of SAPS will maintain the existing retail arrangements, and generation services will be provided free of charge from Essential Energy

Essential Energy's SAPS Customer Engagement Strategy defines that SAPS will only be deployed at sites where customers provide their explicit informed consent, as such the scale of SAPS investments will be subject to customer engagement processes. Our desire is to develop a customer engagement platform to educate and inform customers of the benefits of this transition to improve resilience, reliability and reduce costs for our customers. Preliminary forecasts are for up to 20 sites to be deployed over the next 18-24 months leading into the next regulatory period.

Essential Energy's SAPS program is targeted at addressing a cost to service constraint for the fringe of grid, high cost to serve or low resilient areas of the distribution network. The cost to serve constraint is not an electrical limitation of the network, rather an economic constraint where alternative solutions such as SAPS are cheaper than a traditional network supply. As such all potential SAPS locations will be for single distribution substation sites which generally supply a single customer. Modelling has showed these locations are only viable on low consumption connections with demand generally less than 15kva. The transition of fringe of grid connections to a SAPS will not address any system limitations such as peak demand.

Modelling completed across the Essential Energy network has confirmed more than 1400 locations are economically viable to transition to a DNSP led SAPS. Forecast expenditure has been included in the draft regulatory submission for the delivery of 400 SAPS across the FY24-29 period. The SAPS program will increase deployments year on year for a staged increase, commencing with customer engagement in January 2023 with 40 customers. A target of 50% customer acceptance is expected to enable 20 SAPS to be installed in FY24.

Table 11 – Quantitative Summary of SAPS Projects

Financial Year	Regulated SAPS	Committed Projects	Forecast Projects	Retail Customers
FY23	0	4	-	4
FY24	-	-	20	-

8.4.2 Batteries

Essential Energy will be commissioning our first trial network battery in Port Macquarie in late 2022 as part of our program to develop battery storage on the distribution network. The project consists of a 1MW 2MWh battery which is providing network services (voltage and thermal) to defer the installation of a new zone substation. With a ringfencing waiver approved, the battery will also be used for market facing services when not required for network services. Essential Energy developed the battery project from a Request for Proposal ran in 2021 where proponents provided preferred sizing, business, and operating models.

Essential Energy is also developing an islandable microgrid at Ivanhoe in central NSW to support the 11kv town feeder. A market Expression of Interest (EOI) was released to market in 2022 for submissions on non-network alternatives to support a reliability based islandable microgrid. Submissions are being reviewed in late 2022 with the project recommendations and construction planned in 2023.

Essential Energy has also released a new trial tariff for low voltage batteries from 1st July 2022. This trial is aimed at supporting the economics of low voltage batteries to be deployed by 3rd parties on our network, whilst designed to incentives behaviour to manage peak load and support solar charging. The outputs from this trial will feed into an approved battery tariff available in the next regulatory period.

8.5 Embedded Generation Connection Details

We are unable to differentiate between embedded generation enquiries and general connection enquiries as only simple statistics are recorded. The telephone statistics are based on the number of calls through 13 21 91 and selected option 2 for Network Connections, including solar (previously option 4), and the online portal counts total number of enquiries. The number of embedded generation applications processed has increased significantly from previous years. The introduction of Power of Choice meter contestability and upgrades related to the increased volume of battery installations contributed to an average of approximately 2000 applications per month.

Table 12 – Connection Enquiries and Applications

Connection Enquiries and Applications	Number 2021/22
Phone connection enquiries received	13,470
Online portal connection enquiries received (Due to system changes data is not available – will be reported in FY23)	-
Load connection applications processed	12,021
Generation connection applications processed	29,717
Total connection applications received	50,699
Days to process generation applications	2.6

9. INFORMATION TECHNOLOGY and COMMUNICATION SYSTEMS

9.1 Information Technology

This section of the document defines digital technologies Essential Energy has or is executing to effectively enable the business to deliver on its Customer, Regulatory and Stakeholder requirements. Table 12 outlines the functional area of implementation and a brief description of the investments for the 2021/22 period and Table 13 provides the areas of investment focus for the 2022/23 to 2023/24 period.

Table 13 – Information Technology Investments 2021/22

Functional Area	Technology Initiative
Network Systems	<p>Major initiatives in this area included:</p> <ul style="list-style-type: none"> • Commencement of the replacement of the existing Enterprise Asset Management system (EAM) to support best practice asset management processes • Implementation of supply chain technology to deliver integration with core systems and support field related activities (Enterprise Resource Planning program) • Continuation of the PowerOn Advantage implementation to create a more flexible working environment for field staff and manage demand on Network Operations • Continued digitisation and automation of manual processes to enable field workers, including a digital field risk assessment process (HIRAC) • Commencement of the planning for a Vegetation Management strategic solution • Commencement of the planning and initial foundations to improve works delivery.
Customer Systems	<p>Major initiatives in this area included:</p> <ul style="list-style-type: none"> • Continued remediation of hazard data in existing systems, enabling the capture of new data and ensuring it is provided in a timely manner to both Essential Energy staff and external parties to improve safety • Continuation of new systems and processes to improve the speed and efficiency of Network connections and Ancillary Network Services (ANS) • Customer contact centre digitisation, automation, and optimisation to enhance customer and employee experience.
Enterprise Systems	<p>The major initiatives in this area included:</p> <ul style="list-style-type: none"> • Completion of the implementation of the Enterprise Resource Planning (ERP) replacement program, including Finance, Procurement, Supply Chain and Human Capital Management capabilities • Continuation of business reporting to support the ERP implementation and an archiving solution for PeopleSoft data • Implementation of a replacement for the Records and Content Management system.
Data Management	<p>The major initiatives in this area included the delivery of a new data platform and data readiness improvements to enable transformation initiatives and better inform business decision making.</p>

Functional Area	Technology Initiative
Market Systems	<p>The main initiatives in this area included:</p> <ul style="list-style-type: none"> • Completion of the implementation of 5-minute settlement and additional market compliance requirements including wholesale demand response • Commencing planning for the AEMO Market Settlement and Transfer Solutions (MSATS) Standing Data Review (MSDR) market compliance requirements • Continuation of the upgrade of Billing Systems infrastructure to ensure this remains fully supported.
Technology Infrastructure	<p>Major initiatives in this area included:</p> <ul style="list-style-type: none"> • Continuation of the technology infrastructure modernisation program, including data centre and application rationalisation, and enterprise application integration uplift • Completion of the Cybersecurity tools and capability uplift program (Phase 1) to meet regulatory requirements • Commencement of the Cybersecurity capability uplift program (Phase 2) • Replacement of client devices, in line with asset lifecycle requirements.
Telecommunications Systems	<p>Major initiatives in this area included:</p> <ul style="list-style-type: none"> • Completion of the upgrade of telecommunications security infrastructure • Commencing infrastructure upgrades at a number of small depots, to improve operational resilience and security posture.

Table 14 – Information Technology Investments 2022/23 to 2023/24

Functional Area	Project Description
Network Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Continuation and completion of the replacement of the existing Enterprise Asset Management system (EAM) to improve integration to core systems and support best practice asset management capabilities • Completion of the PowerOn Advantage implementation to create a more flexible working environment for field staff and manage demand on Network Operations • Continued digitisation and automation of manual processes to enable field workers • Uplift of Geospatial information systems and other network systems to enable advanced asset management capabilities • Completion of the implementation of a Vegetation Management strategic solution • Continuation of the uplift to Works Delivery including technology toolsets and processes.
Customer Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Completion of new systems and processes to improve the speed and efficiency of Network connections and Ancillary Network Services (ANS) • Completion of the remediation of hazard data in existing systems, enable capture of new data and ensure it is provided in a timely manner to both Essential Energy staff and external parties to improve safety • Completion of the implementation of Customer contact centre digitisation, automation, and optimisation to enhance customer and employee experience <p>Re-build of the external Essential Energy website to align with the new corporate strategy and to meet the needs of our customers moving forward.</p>

Functional Area	Project Description
Customer Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Completion of new systems and processes to improve the speed and efficiency of Network connections and Ancillary Network Services (ANS) • Completion of the remediation of hazard data in existing systems, enable capture of new data and ensure it is provided in a timely manner to both Essential Energy staff and external parties to improve safety • Completion of the implementation of Customer contact centre digitisation, automation, and optimisation to enhance customer and employee experience • Re-build of the external Essential Energy website to align with the new corporate strategy and to meet the needs of our customers moving forward.
Enterprise Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Commencement of an uplift to IT Service Management processes, tools and technology. • Strengthening the core financial functions, through system, process and data improvements, building on the work undertaken in ERP.
Data Management	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Implementation of data governance tools and an information hub to enable transformation initiatives and better inform business decision making • Completion of the data enablement and integration initiatives to consolidate and centralise data flow and management.
Market Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Completion of implementation of new market compliance requirements, including AEMO MSDR market compliance requirements • Completion of the upgrade of Billing Systems Infrastructure.
Technology Infrastructure	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Continuation of the technology infrastructure modernisation program, including data centre rationalisation and consolidation, application rationalisation, strengthening operational technology infrastructure, and implementation of a strategic integration platform • Continuation of the Cybersecurity uplift program (Phase 2) <p>Replacement of client devices and printers in line with asset lifecycle requirements.</p>
Telecommunications Systems	<p>Major initiatives in this area include:</p> <ul style="list-style-type: none"> • Upgrade of telecommunications network management systems infrastructure and end of life infrastructure <p>Continuation of infrastructure upgrades at small depots to improve operational resilience and security posture.</p>

Table 15 – ICT Investment actual 2021/22 and forecast 2022/23 to 2026/27 (nominal \$)

	Actual (\$M)	Forecast (\$M)				
	FY22	FY23	FY24	FY25	FY26	FY27
Total ICT Investment	72	98	51	84	88	83

The significant increase in expenditure in FY22 and FY23 reflects the peaking of activity relating to the Essential Energy transformation program (Amplify), including the Enterprise Asset Management system replacement.

10. REGIONAL DEVELOPMENT PLANS

The tables in the preceding sections (1-10) are structured along Essential Energy's planning hierarchy of:

Operational Region



Connection Point



Sub-transmission Line



Sub-transmission Substation



Zone Substation



Distribution Feeder.

Semi-geographic single line diagrams of the electrical network for each supply area have been included in the relevant sections of the zone substation and sub-transmission feeder demand forecasts and where system limitations have been identified these are noted on those diagrams.

The map in Figure 6 shows the configuration of one region and ten operational areas. The map also includes the depots and offices associated with each area.



Figure 6 – Diagram of Essential Energy’s Operational Areas

11. GLOSSARY

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMP	Asset Management Plan
AMS	Asset Management System
ANS	Ancillary Network Services
AREMI	Australian Renewable Energy Mapping Infrastructure
CAPEX	Capital Expenditure
CVR	Conservation Voltage Reduction
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EAM	Enterprise Asset Management
ENSMS	Electricity Network Safety Management System
ERP	Enterprise Resource Planning
FSA	Formal Safety Assessment
FY	Financial Year
GWh	Gigawatt-Hour
HIRAC	Hazard Identification Risk Assessment and Control
HV	High Voltage (>1000V AC)
ICT	Information and Communication Technology
IN	Intelligent Network
IPART	Independent Pricing and Regulatory Tribunal
ISF	Institute of Sustainable Futures
kV	Kilovolt
LV	Low Voltage (typically 230V/400V)
MEPS	Minimum Energy Performance Standards
MVA	Megavolt-Ampere
MVA _r	Megavolt-Ampere-Reactive
MW	Megawatt
MWh	Megawatt-Hour
NECF	National Electricity Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
OPEX	Operational Expenditure
PV	Photovoltaic (Solar Panels)
RIT-D	Regulatory Investment Test for Distribution
SAMP	Strategic Asset Management Plan
STS	Sub-transmission Substation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFAIRP	So Far As Is Reasonably Practicable
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TNSP	Transmission Network Service Provider
TX	Transformer
VCR	Value of Customer Reliability
WHS	Workplace Health and Safety
ZS	Zone Substation

12. NER CROSS REFERENCE

The following is an extract of relevant clauses from Schedule 5.8 of the National Electricity Rules. Clause 11.141.10 excludes the recently added components to Schedule 5.8 from the 2022 Distribution Annual Planning Report document. These new clauses will be required in future Distribution Annual Planning Reports.

National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	DAPR 2022 Section
(a) information regarding the Distribution Network Service Provider and its network, including:	
(1) a description of its network;	1.1 About Essential Energy
(2) a description of its operating environment;	1.1.1 Operating Environment
(3) the number and types of its distribution assets;	1.1.2 Essential Energy Statistics
(4) methodologies used in preparing the Distribution Annual Planning Report, including methodologies used to identify system limitations and any assumptions applied; and	1.2 Essential Energy's Network
(5) analysis and explanation of any aspects of forecasts and information provided in the Distribution Annual Planning Report that have changed significantly from previous forecasts and information provided in the preceding year;	1.2.1 Number and Types of Distribution Assets
	1.3 Annual Planning Review
	1.3.1 Network Planning Process
	1.4 Significant changes from previous DAPR
	1.4.1 Analysis and explanation of forecast changes
	1.4.2 Analysis and explanation of changes in other information
(b) forecasts for the forward planning period, including at least:	
(1) a description of the forecasting methodology used, sources of input information, and the assumptions applied;	2.1 Load Forecasting Strategy
	2.2 Load Forecasting Methodology and Process
	2.2.1 Sources of load forecast input information
	2.2.2 Assumptions applied to load forecasts
	2.3 Forecast use of Distribution Services by Embedded Generating Units
(2) load forecasts:	Data attachment (DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx)
(i) at the transmission-distribution connection points;	
(ii) for sub-transmission lines; and	
(iii) for zone substations, including, where applicable, for each item specified above:	
(iv) total capacity;	
(v) firm delivery capacity for summer periods and winter periods;	
(vi) peak load (summer or winter and an estimate of the number of hours per year that 95% of peak load is expected to be reached);	
(vii) power factor at time of peak load;	
(viii) load transfer capacities; and	
(ix) generation capacity of known embedded generating units;	

National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	DAPR 2022 Section
(b) forecasts for the forward planning period, including at least:	
(2A) forecast use of distribution services by embedded generating units: (i) at the transmission-distribution connection points; (ii) for sub-transmission lines; and (iii) for zone substations, including, where applicable for each item specified above: (iv) total capacity to accept supply from embedded generating units; (v) firm delivery capacity for each period during the year; (vi) peak supply into the distribution network from embedded generating units (at any time during the year) and an estimate of the number of hours per year that 95% of the peak is expected to be reached; and (vii) power factor at time of peak supply into the distribution network;	Data attachment (DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx)
(3) forecasts of future transmission-distribution connection points (and any associated connection assets), sub-transmission lines and zone substations, including for each future transmission-distribution connection point and zone substation: (i) location; (ii) future loading level; and (iii) proposed commissioning time (estimate of month and year);	2.5 Future Connection Points
(4) forecasts of the Distribution Network Service Provider's performance against any reliability targets in a service target performance incentive scheme; and	2.7 Forecast of Reliability Target Performance
(5) a description of any factors that may have a material impact on its network, including factors affecting: (i) fault levels; (ii) voltage levels; (iii) other power system security requirements; (iv) the quality of supply to other Network Users (where relevant); and (v) ageing and potentially unreliable assets;	Data attachment (DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx)
(b1) for all network asset retirements, and for all network asset de-ratings that would result in a system limitation, that are planned over the forward planning period, the following information in sufficient detail relative to the size or significance of the asset:	
(1) a description of the network asset, including location; (2) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset; (3) the date from which the Distribution Network Service Provider proposes that the network asset will be retired or de-rated; and (4) if the date to retire or de-rate the network asset has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred;	3.4 Network Asset Retirements and De-ratings – Sub-transmission 3.5 Network Asset Retirements and De-ratings – Zone Substation

National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:	DAPR 2022 Section
(b2) for the purposes of subparagraph (b1), where two or more network assets are:	
(1) of the same type; (2) to be retired or de-rated across more than one location; (3) to be retired or de-rated in the same calendar year; and (4) each expected to have a replacement cost less than \$200,000 (as varied by a cost threshold determination), those assets can be reported together by setting out in the Distribution Annual Planning Report: (5) a description of the network assets, including a summarised description of their locations; (6) the reasons, including methodologies and assumptions used by the Distribution Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets; (7) the date from which the Distribution Network Service Provider proposes that the network assets will be retired or de-rated; and (8) if the calendar year to retire or de-rate the network assets has changed since the previous Distribution Annual Planning Report, an explanation of why this has occurred;	3.5.4 Combined Asset Retirements and De-Ratings
(c) information on system limitations for sub-transmission lines and zone substations, including at least:	
(1) estimates of the location and timing (month(s) and year) of the system limitation; (2) analysis of any potential for load transfer capacity between supply points that may decrease the impact of the system limitation or defer the requirement for investment; (3) impact of the system limitation, if any, on the capacity at transmission-distribution connection points; (4) a brief discussion of the types of potential solutions that may address the system limitation in the forward planning period, if a solution is required; and (5) where an estimated reduction in forecast load would defer a forecast system limitation for a period of at least 12 months, include: (i) an estimate of the month and year in which a system limitation is forecast to occur as required under subparagraph (1); (ii) the relevant connection points at which the estimated reduction in forecast load may occur; and (iii) the estimated reduction in forecast load in MW or improvements in power factor needed to defer the forecast system limitation;	3.1 Sub-transmission Feeder Limitations 3.2 Sub-transmission and Zone Substation Limitations

<p>National Electricity Rules Version 187</p> <p>Schedule 5.8 Distribution Annual Planning Report</p> <p>For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</p>	<p>DAPR 2022 Section</p>
<p>(d) for any primary distribution feeders for which a Distribution Network Service Provider has prepared forecasts of maximum demands under clause 5.13.1(d)(1)(iii) and which are currently experiencing an overload, or are forecast to experience an overload in the next two years the Distribution Network Service Provider must set out:</p>	
<p>(1) the location of the primary distribution feeder;</p> <p>(2) the extent to which load exceeds, or is forecast to exceed, 100% (or lower utilisation factor, as appropriate) of the normal cyclic rating under normal conditions (in summer periods or winter periods);</p> <p>(3) the types of potential solutions that may address the overload or forecast overload; and</p> <p>(4) where an estimated reduction in forecast load would defer a forecast overload for a period of 12 months, include:</p> <ul style="list-style-type: none"> (i) estimate of the month and year in which the overload is forecast to occur; (ii) a summary of the location of relevant connection points at which the estimated reduction in forecast load would defer the overload; (iii) the estimated reduction in forecast load in MW needed to defer the forecast system limitation; 	<p>3.3 Primary Distribution Feeder Limitations</p>
<p>(d2) for a SAPS enabled network, information on system limitations in the forward planning period for which a potential solution is a regulated SAPS</p>	
<p>(1) Estimate of the location and timing (months(s) and year) of the system limitation; and</p> <p>(2) A brief discussion of the types of potential stand-alone power systems that may address the system limitation;</p>	<p>8.4 Non network solutions</p>
<p>(e) a high-level summary of each RIT-D project for which the regulatory investment test for distribution has been completed in the preceding year or is in progress, including:</p>	
<p>(1) if the regulatory investment test for distribution is in progress, the current stage in the process;</p> <p>(2) a brief description of the identified need;</p> <p>(3) a list of the credible options assessed or being assessed (to the extent reasonably practicable);</p> <p>(4) if the regulatory investment test for distribution has been completed a brief description of the conclusion, including:</p> <ul style="list-style-type: none"> (i) the net economic benefit of each credible option; (ii) the estimated capital cost of the preferred option; and (iii) the estimated construction timetable and commissioning date (where relevant) of the preferred option; and <p>(5) any impacts on Network Users, including any potential material impacts on connection charges and distribution use of system charges that have been estimated;</p>	<p>4.1 Regulatory Test / RIT-Ds Completed or in Progress</p>
<p>(f) for each identified system limitation which a Distribution Network Service Provider has determined will require a regulatory investment test for distribution, provide an estimate of the month and year when the test is expected to commence;</p>	<p>4.2 Potential RIT-Ds for Identified System Limitations</p>

National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		DAPR 2022 Section
(g) a summary of all committed investments to be carried out within the forward planning period with an estimated capital cost of \$2 million or more (as varied by a cost threshold determination) that are to address:		
(1) a refurbishment or replacement need; or	4.3 Urgent and Unforeseen Investments	
(2) an urgent and unforeseen network issue as described in clause 5.17.3(a)(1), including:		
(1) a brief description of the investment, including its purpose, its location, the estimated capital cost of the investment and an estimate of the date (month and year) the investment is expected to become operational;		
(2) a brief description of the alternative options considered by the Distribution Network Service Provider in deciding on the preferred investment, including an explanation of the ranking of these options to the committed project. Alternative options could include, but are not limited to, generation options, demand side options, and options involving other distribution or transmission networks;		
(h) the results of any joint planning undertaken with a Transmission Network Service Provider in the preceding year, including:		
(1) a summary of the process and methodology used by the Distribution Network Service Provider and relevant Transmission Network Service Providers to undertake joint planning;	5.1 Results of Joint Planning with the TNSP Transgrid	5.2 Results of Joint Planning with the TNSP Powerlink
(2) a brief description of any investments that have been planned through this process, including the estimated capital costs of the investment and an estimate of the timing (month and year) of the investment; and		
(3) where additional information on the investments may be obtained;		
(i) the results of any joint planning undertaken with other Distribution Network Service Providers in the preceding year, including:		
(1) a summary of the process and methodology used by the Distribution Network Service Providers to undertake joint planning;	5.3 Results of Joint Planning with the DNSP Energex	5.4 Results of Joint Planning with the DNSP Ergon 5.5 Results of Joint Planning with the DNSP Ausgrid 5.6 Results of Joint Planning with the DNSP Endeavour Energy 5.7 Results of Joint Planning with the DNSP Evoenergy 5.8 Results of Joint Planning with the DNSP Powercor Australia
(2) a brief description of any investments that have been planned through this process, including the estimated capital cost of the investment and an estimate of the timing (month and year) of the investment; and		
(3) where additional information on the investments may be obtained;		

<p>National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:</p>	<p>DAPR 2022 Section</p>
<p>(j) information on the performance of the Distribution Network Service Provider's network, including:</p>	
<p>(1) a summary description of reliability measures and standards in applicable regulatory instruments;</p> <p>(2) a summary description of the quality of supply standards that apply, including the relevant codes, standards and guidelines;</p> <p>(3) a summary description of the performance of the distribution network against the measures and standards described under subparagraphs (1) and (2) for the preceding year;</p> <p>(4) where the measures and standards described under subparagraphs (1) and (2) were not met in the preceding year, information on the corrective action taken or planned;</p> <p>(5) a summary description of the Distribution Network Service Provider's processes to ensure compliance with the measures and standards described under subparagraphs (1) and (2); and</p> <p>(6) an outline of the information contained in the Distribution Network Service Provider's most recent submission to the AER under the service target performance incentive scheme;</p>	<p>6.1 Reliability Performance</p> <p>6.2 Quality of Supply Performance</p>
<p>(k) information on the Distribution Network Service Provider's asset management approach, including:</p>	
<p>(1) a summary of any asset management strategy employed by the Distribution Network Service Provider;</p>	<p>7.1 Essential Energy's Asset Management Approach</p> <p>7.2 Network and Asset Strategies</p>
<p>(1A) an explanation of how the Distribution Network Service Provider takes into account the cost of distribution losses when developing and implementing its asset management and investment strategy;</p>	<p>7.3 Treatment of Distribution Losses</p>
<p>(2) a summary of any issues that may impact on the system limitations identified in the Distribution Annual Planning Report that has been identified through carrying out asset management; and</p>	<p>7.4 Asset Issues Impacting Identified System Limitations</p>
<p>(3) information about where further information on the asset management strategy and methodology adopted by the Distribution Network Service Provider may be obtained;</p>	<p>7.5 Obtaining Further Information on the Asset Management Strategy and Methodology</p>
<p>(l) information on the Distribution Network Service Provider's demand management activities, including:</p>	
<p>(1) a qualitative summary of:</p> <ul style="list-style-type: none"> (i) non-network options that have been considered in the past year, including generation from embedded generating units; (ii) key issues arising from applications to connect embedded generating units received in the past year; (iii) actions taken to promote non-network proposals in the preceding year, including generation from embedded generating units; and (iv) the Distribution Network Service Provider's plans for demand management and generation from embedded generating units over the forward planning period; 	<p>8.1 Demand Management Activities in the Preceding Year</p> <p>8.2 Plans for demand management and embedded generation</p> <p>8.3 Issues arising from applications to connect embedded generation</p>

National Electricity Rules Version 187 Schedule 5.8 Distribution Annual Planning Report For the purposes of clause 5.13.2(c), the following information must be included in a Distribution Annual Planning Report:		DAPR 2022 Section
(l) information on the Distribution Network Service Provider’s demand management activities, including:		
(2) a quantitative summary of: (i) connection enquiries received under clause 5.3A.5; (ii) applications to connect received under clause 5.3A.9; and (iii) the average time taken to complete applications to connect;		8.5 Embedded Generation Connection Details
(m) information on the Distribution Network Service Provider’s investments in information technology and communication systems which occurred in the preceding year, and planned investments in information technology and communication systems related to management of network assets in the forward planning period; and		9.1 Information Technology
(n) a regional development plan consisting of a map of the Distribution Network Service Provider’s network as a whole, or maps by regions, in accordance with the Distribution Network Service Provider’s planning methodology or as required under any regulatory obligation or requirement, identifying:		
(1) sub-transmission lines, zone substations and transmission-distribution connection points; and		Data attachment (DAPR 2022 BSP, ZS and Lines Extract Summary.xlsx) 10 Regional Development Plans
(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders.		
(o) the analysis of the known and potential interactions between:		
(1) any emergency frequency control schemes, or emergency controls in place under clause S5.1.8, on its network; and		6.3 Frequency Control and Protection System
(2) protection systems or control systems of plant connected to its network (including consideration of whether the settings of those systems are fit for purpose for the future operation of its network), undertaken under clause 5.13.1(d)(6), including a description of proposed actions to be undertaken to address any adverse interactions		
(p) for a SAPS enable network, information on the Distribution Network Service Provider’s activities in relation to DNSP-led SAPS projects including:		
(1) Opportunities to develop DNSP-led SAPS projects that have been considered in the past year; (2) Committed projects to implement a regulated SAPS over the forward planning period; and (3) A quantitative summary of: (i) The total number of regulated SAPS in the network; and (ii) The total number of premises of retail customer supplied by means of those regulated SAPS		8.4.1 Stand alone power systems