Regulatory Investment Test for Distribution (RIT-D)

Connection of a Major Customer in the Bundaberg Region

Draft Project Assessment Report

8 September 2023

ERGON ENERGY NETWORK

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres (around 97% of the state of Queensland) from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

Identified Need

Ergon Energy has received a connection application for a major customer to connect to the network in the Bundaberg region with a requirement for a large supply. The connection arrangement, which has been agreed to through consultation with the customer, is for a dedicated connection which is composed of both Alternate Control Services (ACS) and Standard Control Services (SCS) as defined in Chapter 10 of the National Electricity Rules (NER).

Works classified as ACS requires that the customer fund the cost directly. SCS works are those that are central to the supply of electricity and provided by Ergon Energy, including design, construction and operation of the shared network. Cost for these services is recovered through network charges for all relevant customers.

The RIT-D only considers the SCS component, as this is network expenditure under the identified need; however, any solution must be capable of supplying the major customer up to 10MW and provide an N-1 supply. The proposed connection arrangement requires that a new 2 x 20/25MVA 66/11kV Thabeban substation (THAB) is established at Thabeban, a new 66kV feeder from Bundaberg (T20) 132/66kV substation (BUND) to THAB and new 66kV feeder from South Bundaberg 66/11kV substation (SOBU) to THAB. The completion date for the works is October 2026, which is driven by the customer timeframes for connection.

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Ergon Energy has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Bundaberg supply area in a reliable, safe and cost-effective manner and for the connection of a major customer. Accordingly, this investment is subject to a RIT-D.

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Ergon Energy published a Notice of No Non-Network Options Report for the above described network constraint on 8 September 2023.

One potentially feasible option has been investigated:

- **Option A:** Develop Thabeban 66/11kV Substation

This Draft Project Assessment Report (DPAR), where Ergon Energy provides both technical and economic information about possible solutions, has been prepared in accordance with the requirements of clause 5.17.4(i) of the NER.

Ergon Energy's preferred solution to address the identified need is Option A – Develop Thabeban 66/11kV Substation.

The DPAR seeks information from interested parties about possible alternate solutions to address the need for investment.

Submissions in writing are due on the **25 October 2023** by 4pm and must be lodged to demandmanagement@ergon.com.au

For further information and inquiries please contact:

E: demandmanagement@ergon.com.au
P: 13 74 66

CONTENTS

1. INTRODUCTION

This Draft Project Assessment Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(i) of the NER.

This report represents the second stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Bundaberg network area.

In preparing this RIT-D, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Bundaberg area.
- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of the single credible option and accompanying explanatory statements regarding the results along with NPV for options that will address only the network limitations.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.
- Is an invitation to registered participants and interested parties to make submissions.

1.2. Contact Details

Submissions in writing are due by 4pm on **25 October 2020** and should be lodged to demandmanagement@ergon.com.au.

For further information and inquiries please contact:

Ergon Energy Corporation Limited ABN 50 087 646 062

E: demandmanagement@ergon.com.au
P: 13 74 66

2. BACKGROUND

2.1. Geographic Region

The Bundaberg region is supplied via five 66/11kV zone substations, West Bundaberg (WEBU), Bundaberg Central (BUCE), East Bundaberg (EABU), South Bundaberg (SOBU) and Bargara (BARG). The 66kV network is supplied from Bundaberg (T20) 132/66kV Bulk Supply Substation, where the 66kV network forms a ring, connecting WEBU, BUCE, EABU and SOBU, with Bargara supplied radially from South Bundaberg. A major customer has requested electrical connection within the Thabeban suburb of the Bundaberg region. During the consultation with the customer a planning report was developed to identify the credible options for connection, with the preferred option being an N-1 11kV connection from a new 66/11kV substation located near Thabeban.

The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1 and Figure 2.

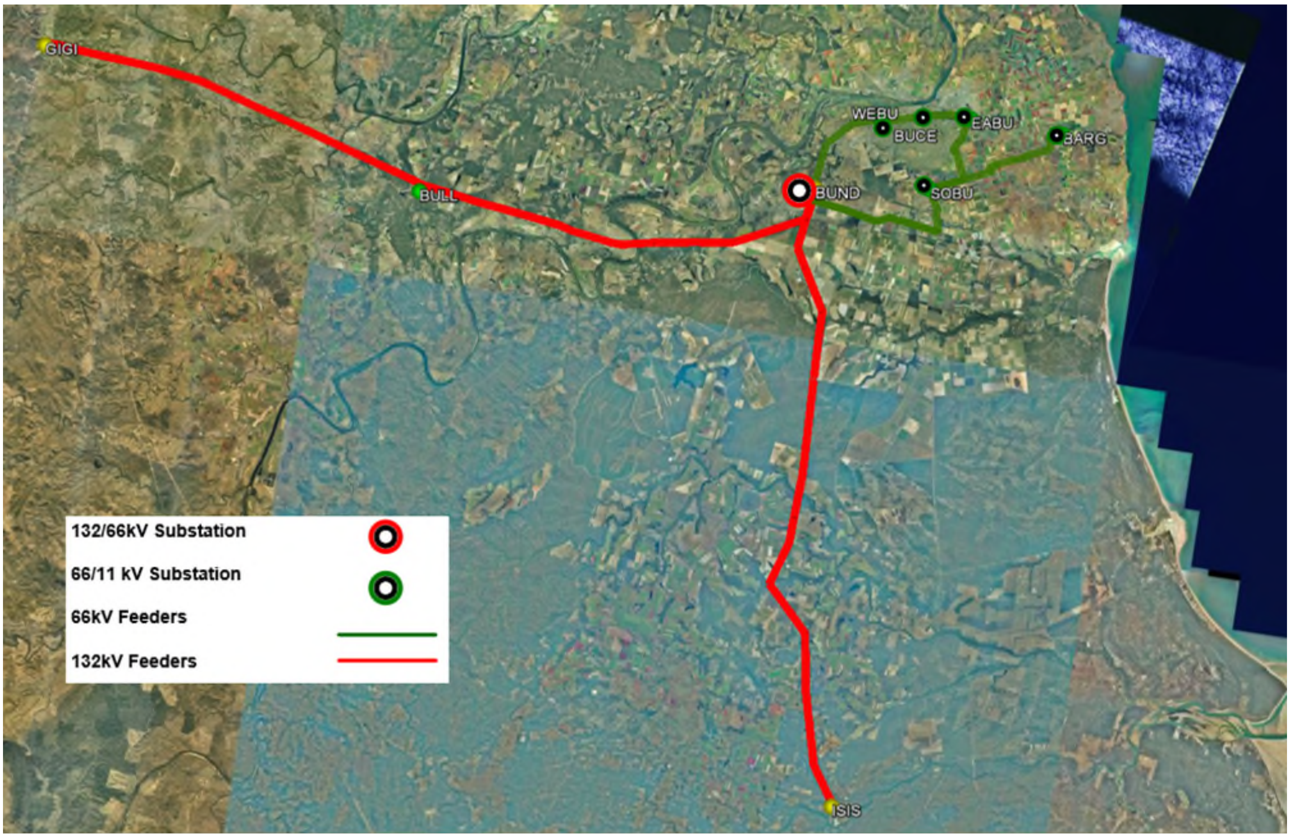

Figure 1: Existing network arrangement (geographic view)

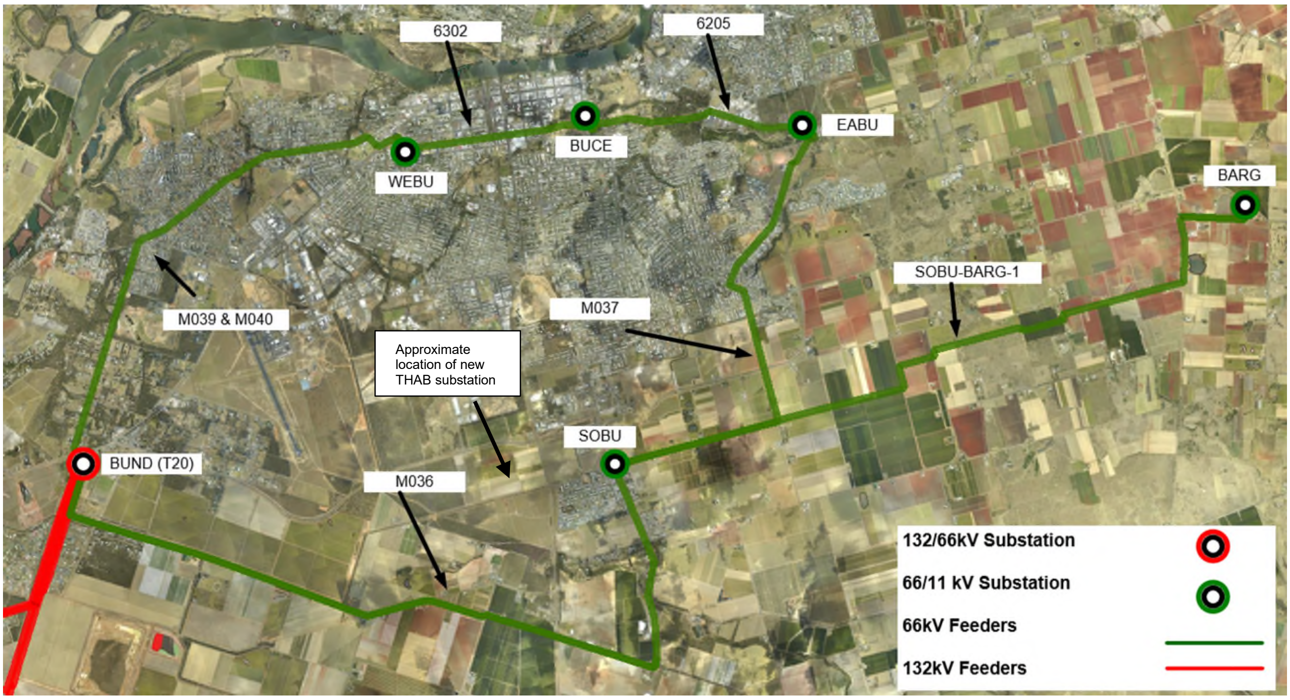

Figure 2: Existing Geographic view of the network arrangement (Zoomed)

2.2. Existing Supply System

The existing 66kV network is supplied from Bundaberg (T20) 132/66kV Bulk Supply substation, which is located approximately 2.5km West of the Bundaberg Airport. The 66kV network supplies the Bundaberg ring, connecting WEBU, BUCE, EABU and SOBU; BARG is also supplied radially from SOBU at 66kV. Each of these zone substations subsequently supplies local customers at 11kV.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 3.

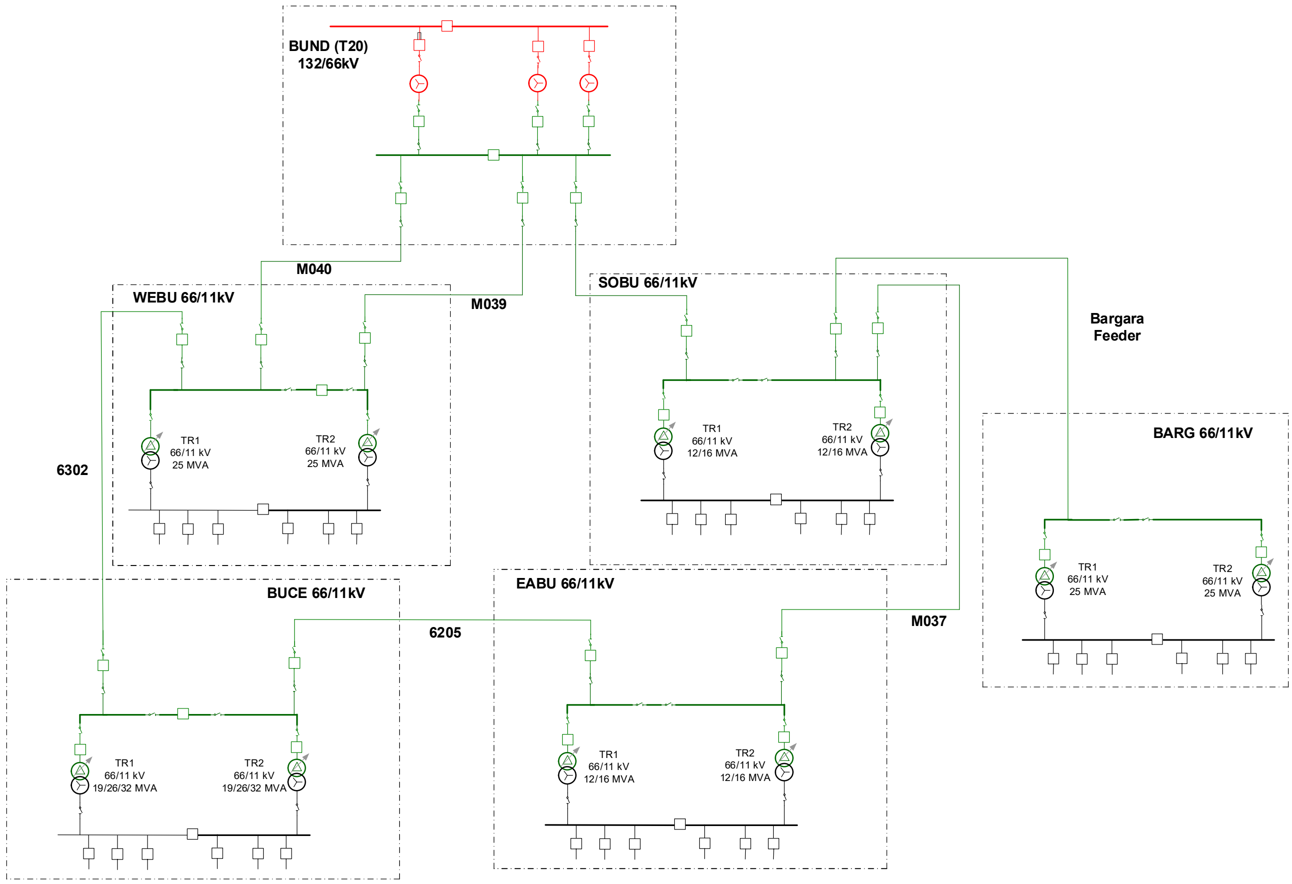

Figure 3: Existing network arrangement (schematic view)

2.3. Load Profiles / Forecasts

The load profiles pertinent to this project include WEBU, BUCE, EABU and SOBU. Each of these are provided in the following sections. The loads of the four zone substations are predominantly summer peaking.

2.3.1. Full Annual Load Profile

The full annual load profile for West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg Substation over the 2022/23 financial year are shown in Figure 4, Figure 5, Figure 6, and Figure 7.

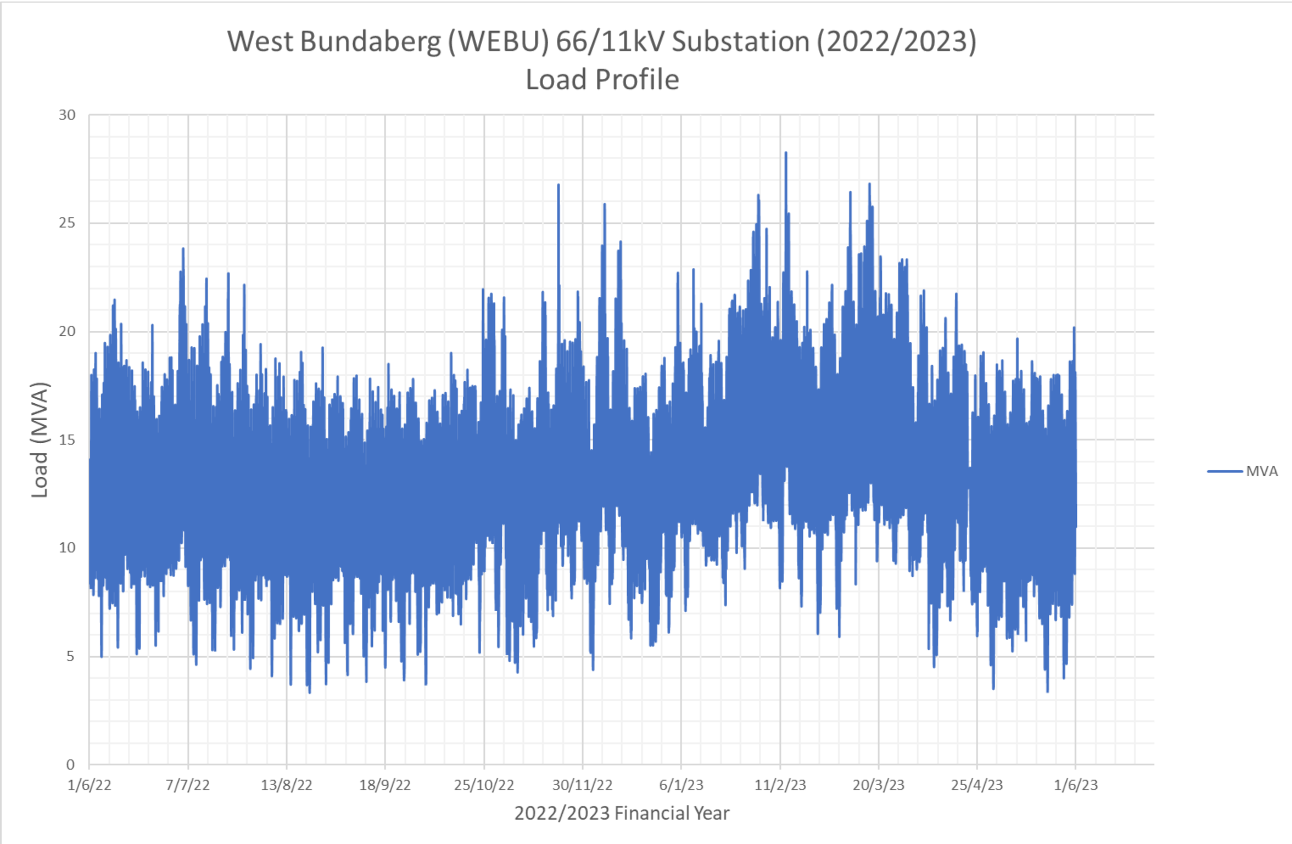

Figure 4: West Bundaberg Substation actual annual load profile

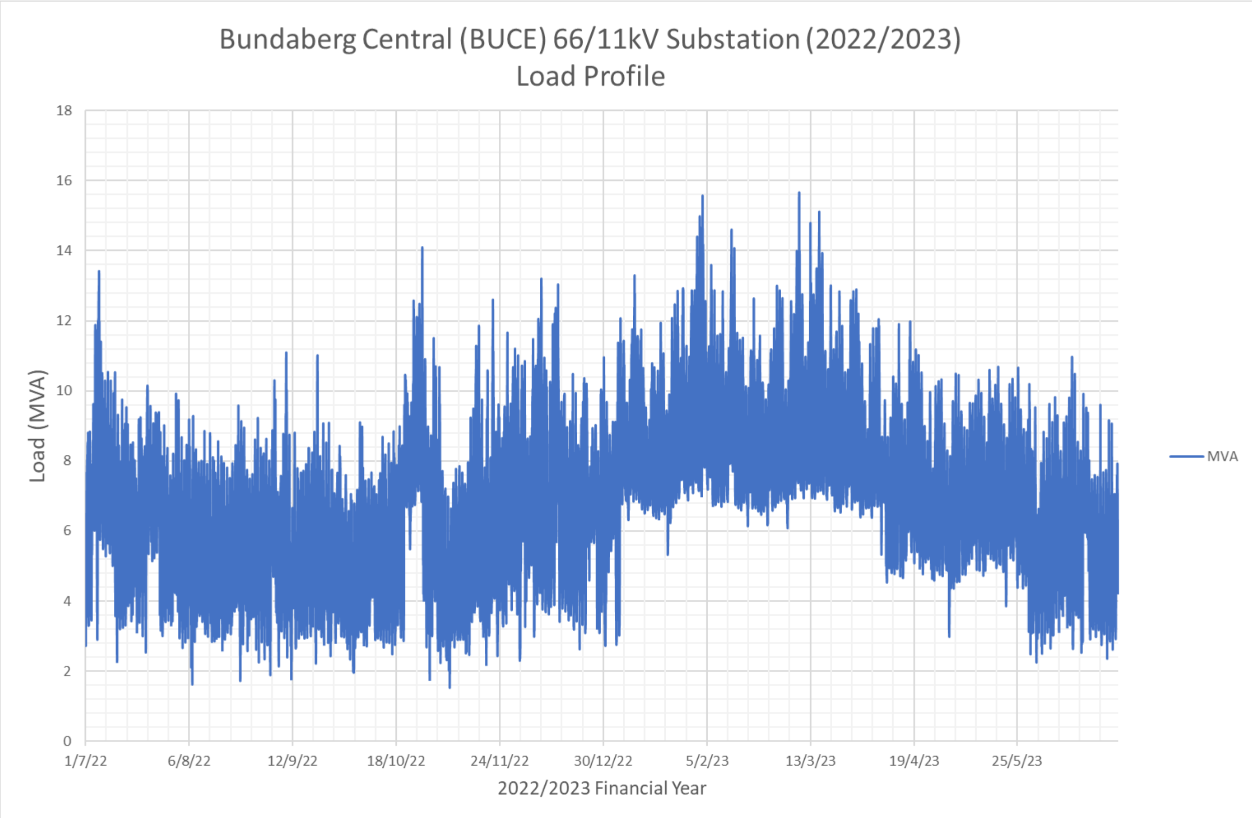

Figure 5: Bundaberg Central Substation actual annual load profile

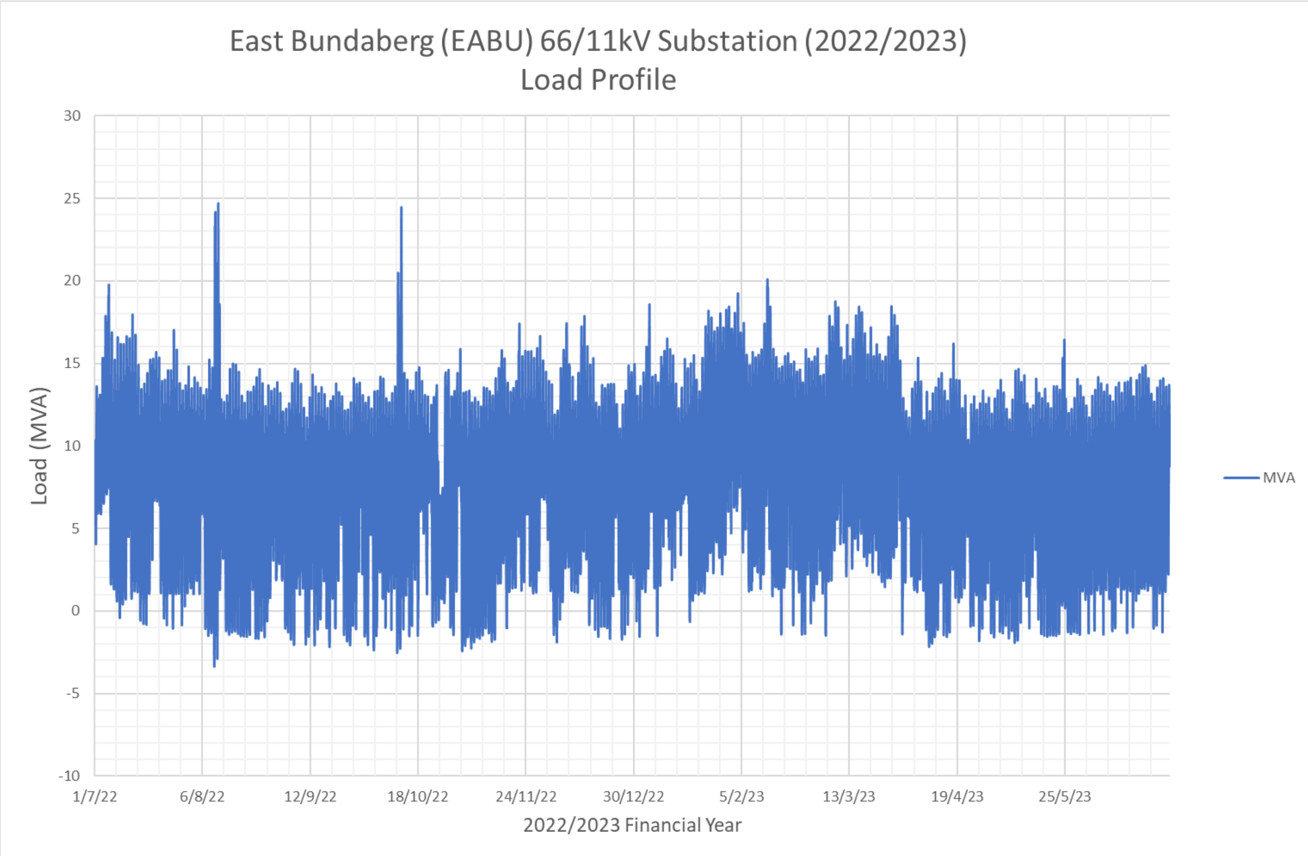

Figure 6: East Bundaberg Substation actual annual load profile

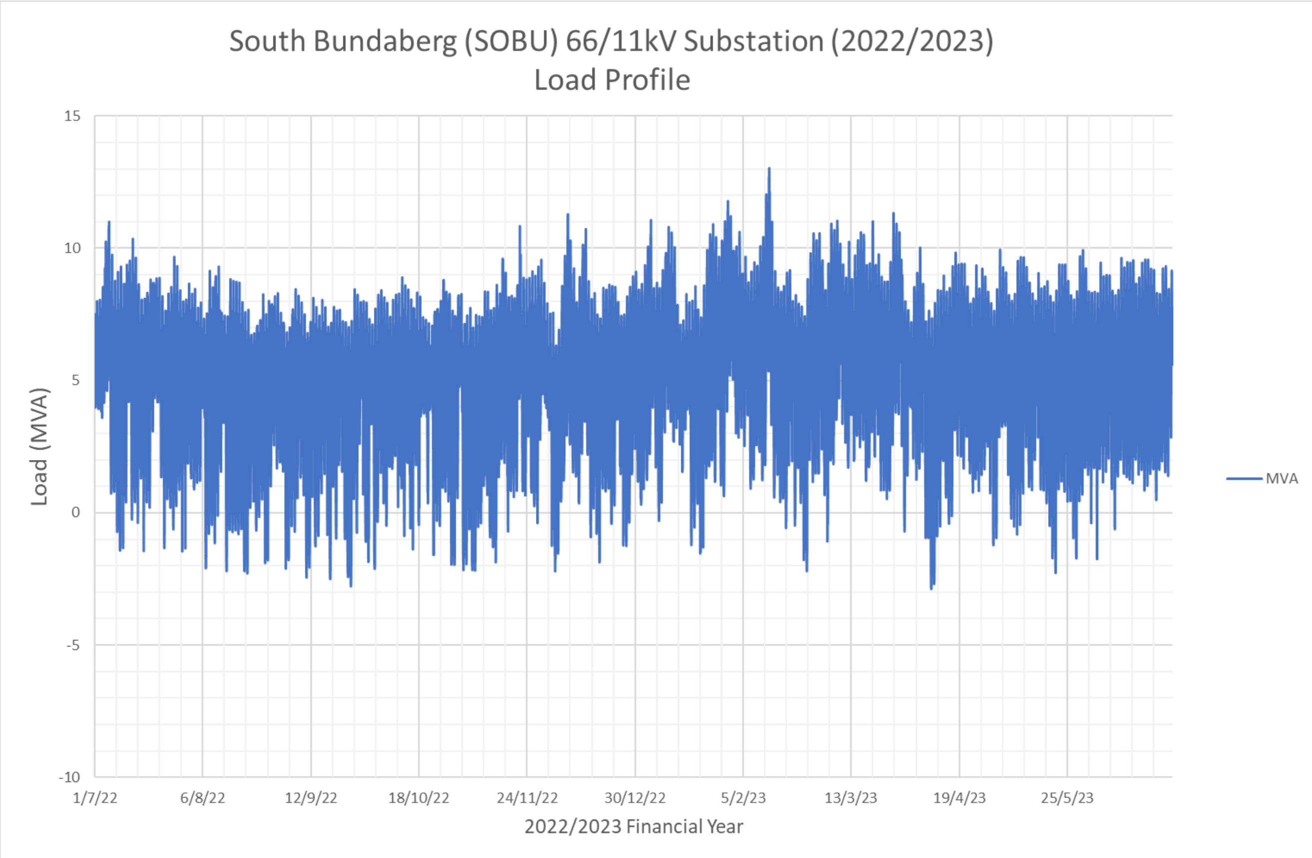

Figure 7: South Bundaberg Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for West Bundaberg, Bundaberg Central, East Bundaberg and South Bundaberg Substation over the 2022/23 financial year is shown in Figure 8, Figure 9, Figure 10, and Figure 11.

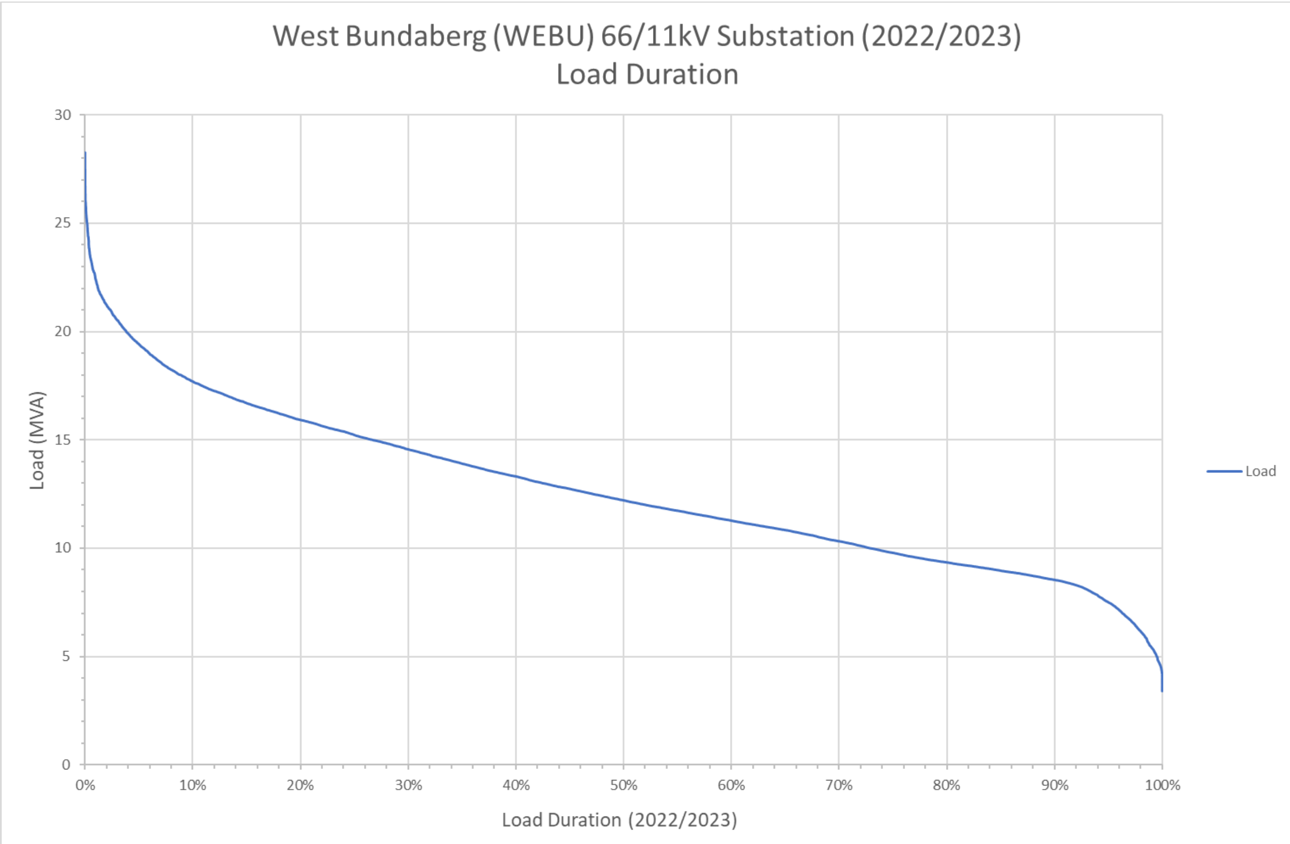

Figure 8: West Bundaberg Substation load duration curve

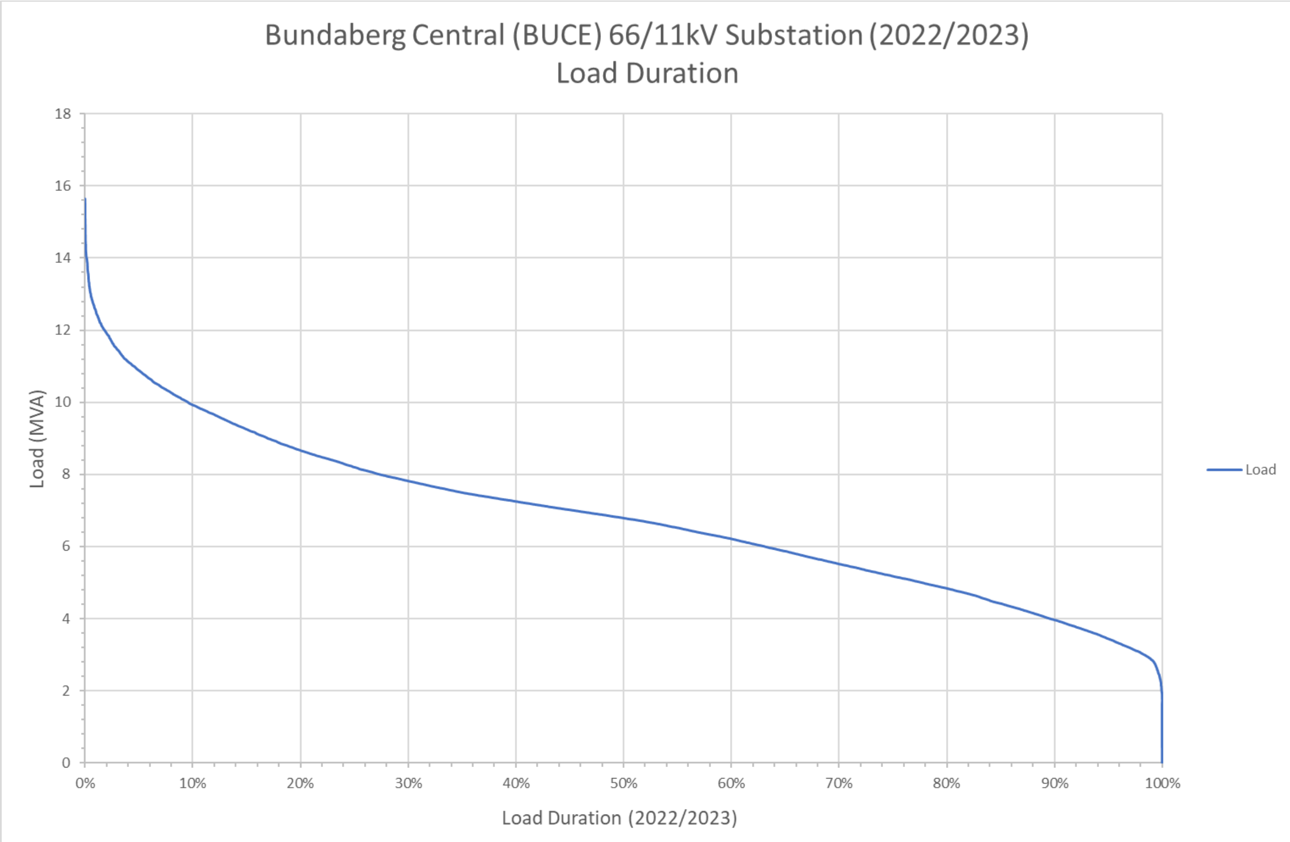

Figure 9: Bundaberg Central Substation load duration curve

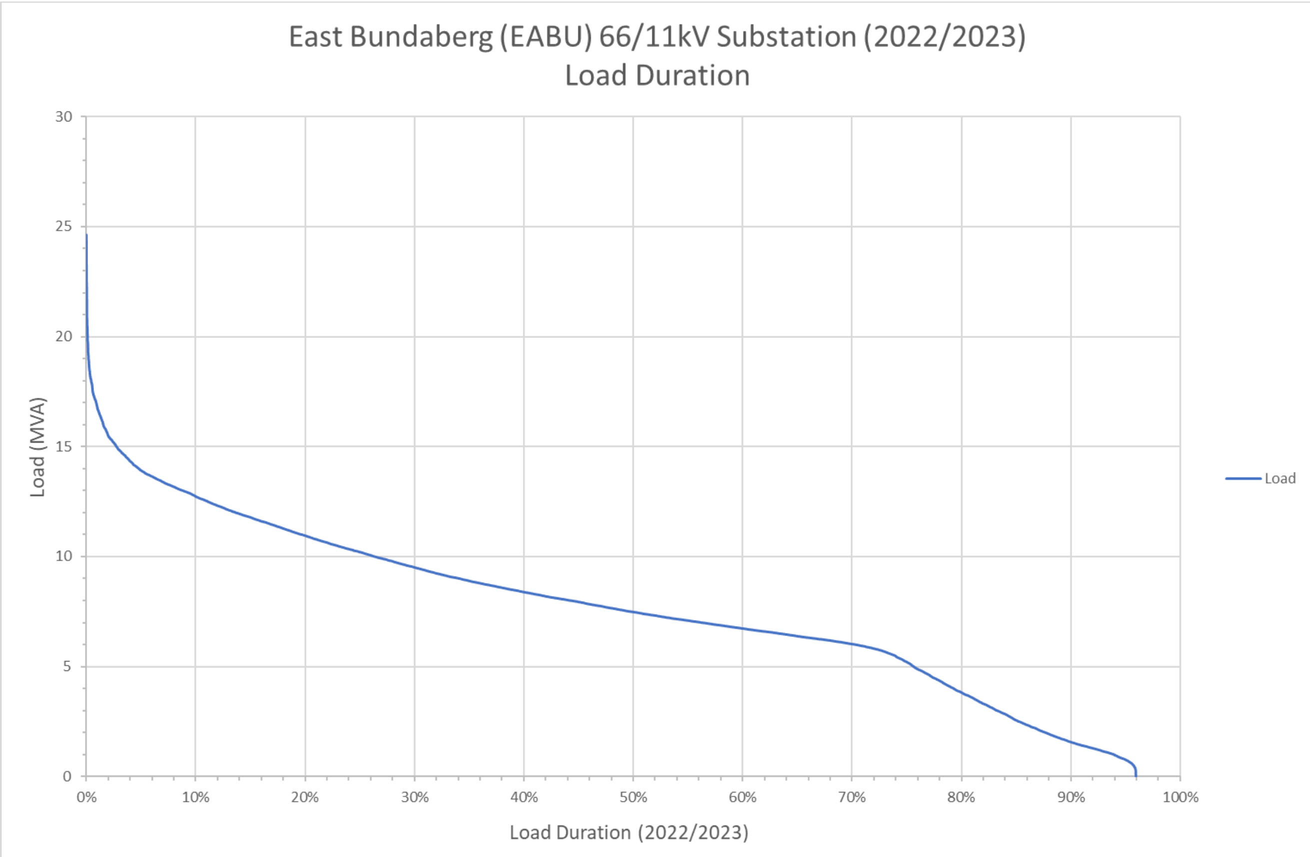

Figure 10: East Bundaberg Substation load duration curve

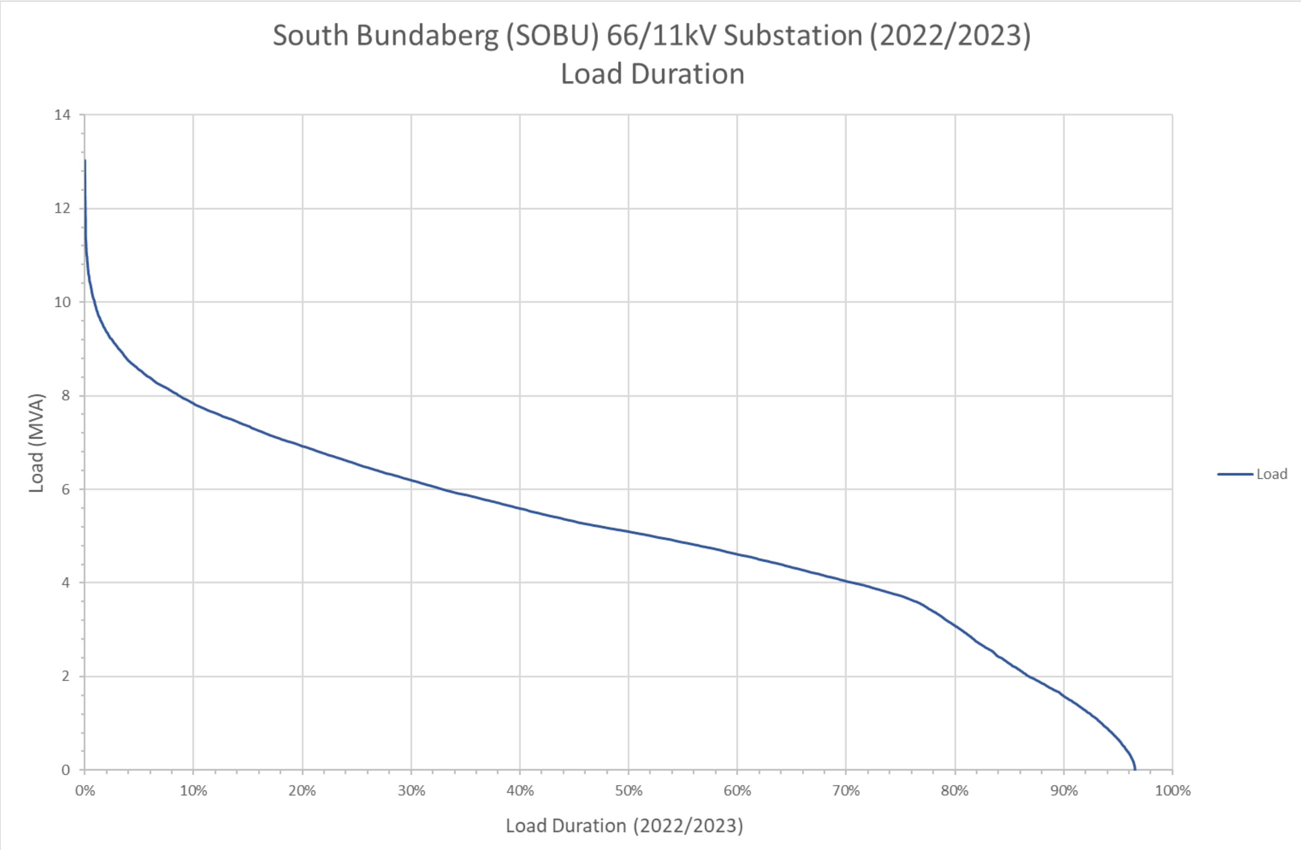

Figure 11: South Bundaberg Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 12, Figure 13, Figure 14, and Figure 15. It can be noted that there is a daytime minimum demand with an evening peak for most of the zone substations in the Bundaberg region.

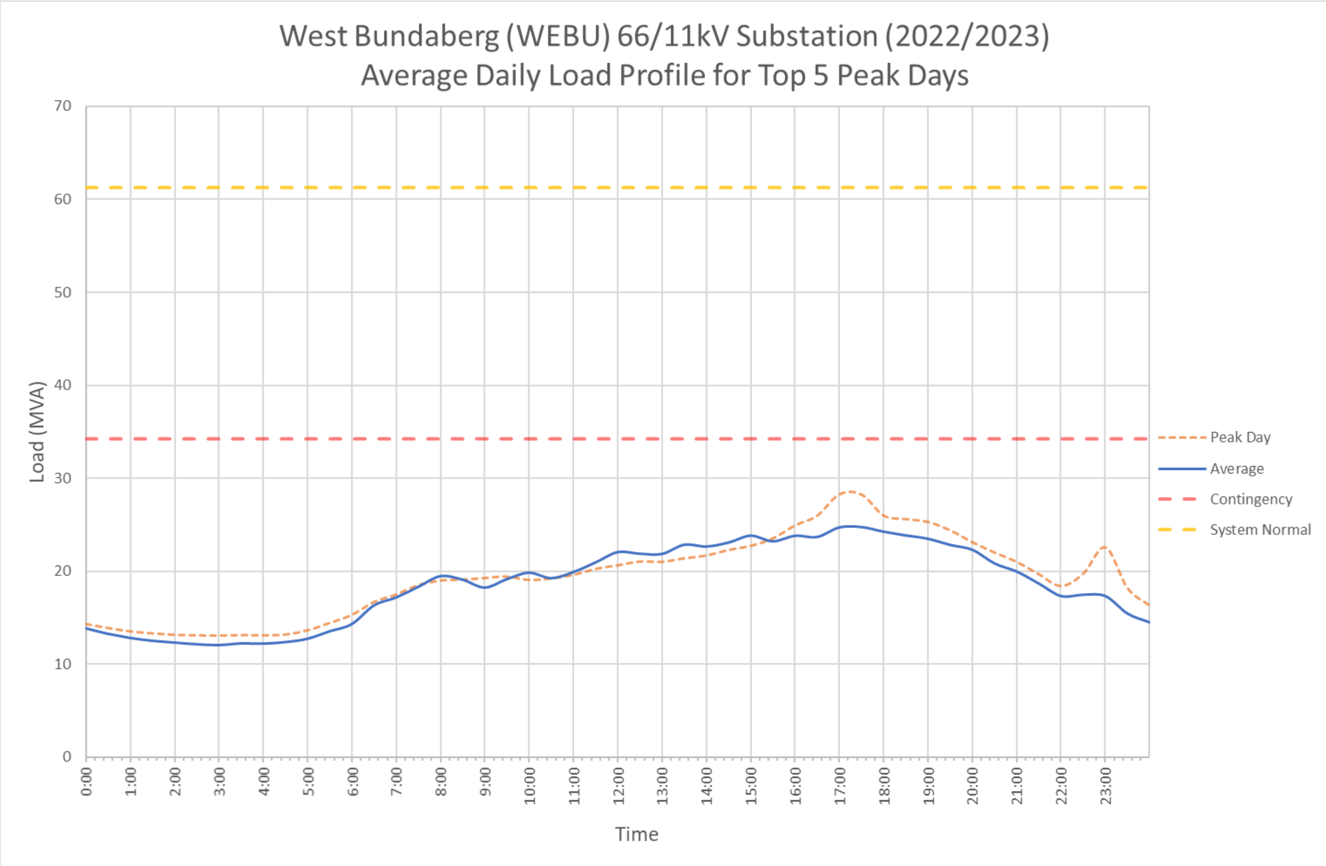

Figure 12: West Bundaberg Substation average peak weekday load profile (summer)

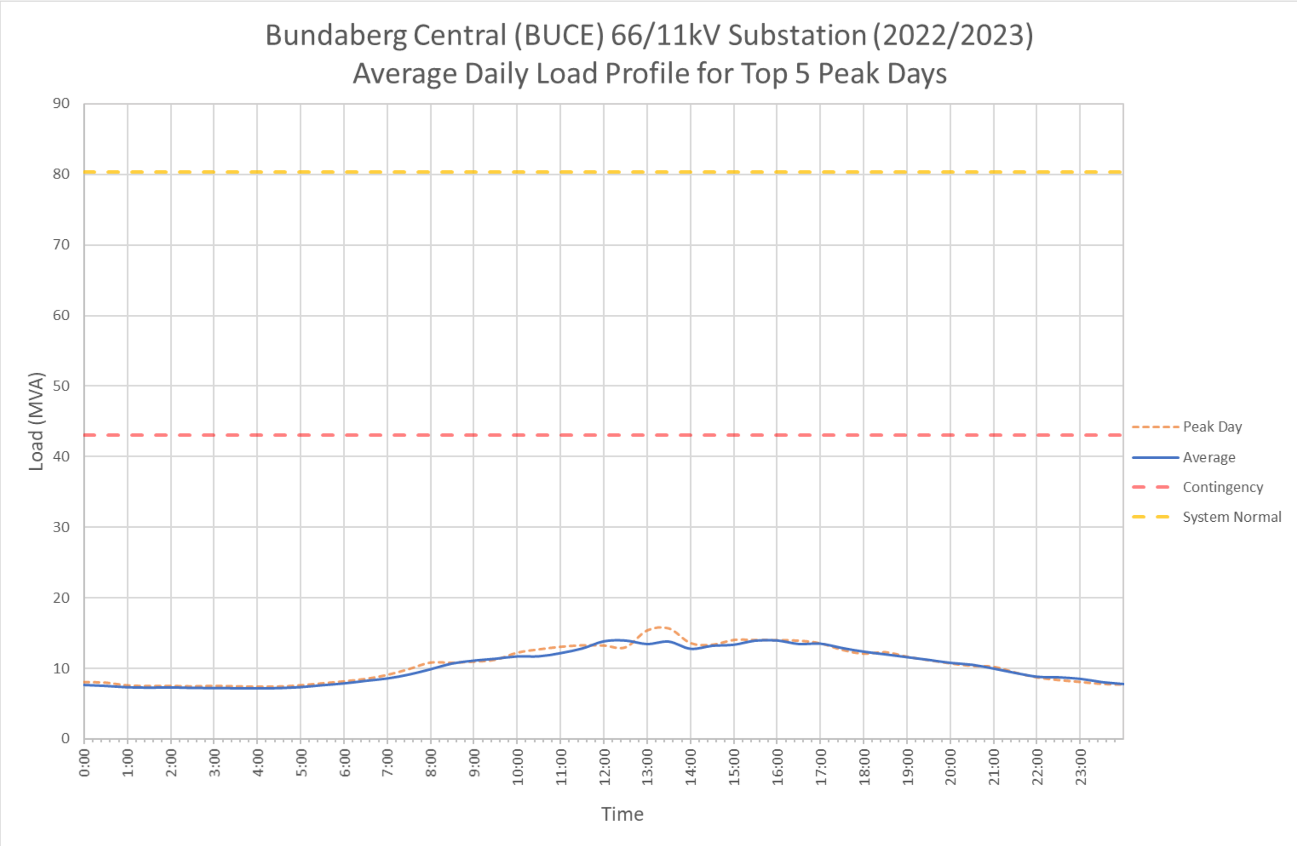

Figure 13: Bundaberg Central Substation average peak weekday load profile (summer)

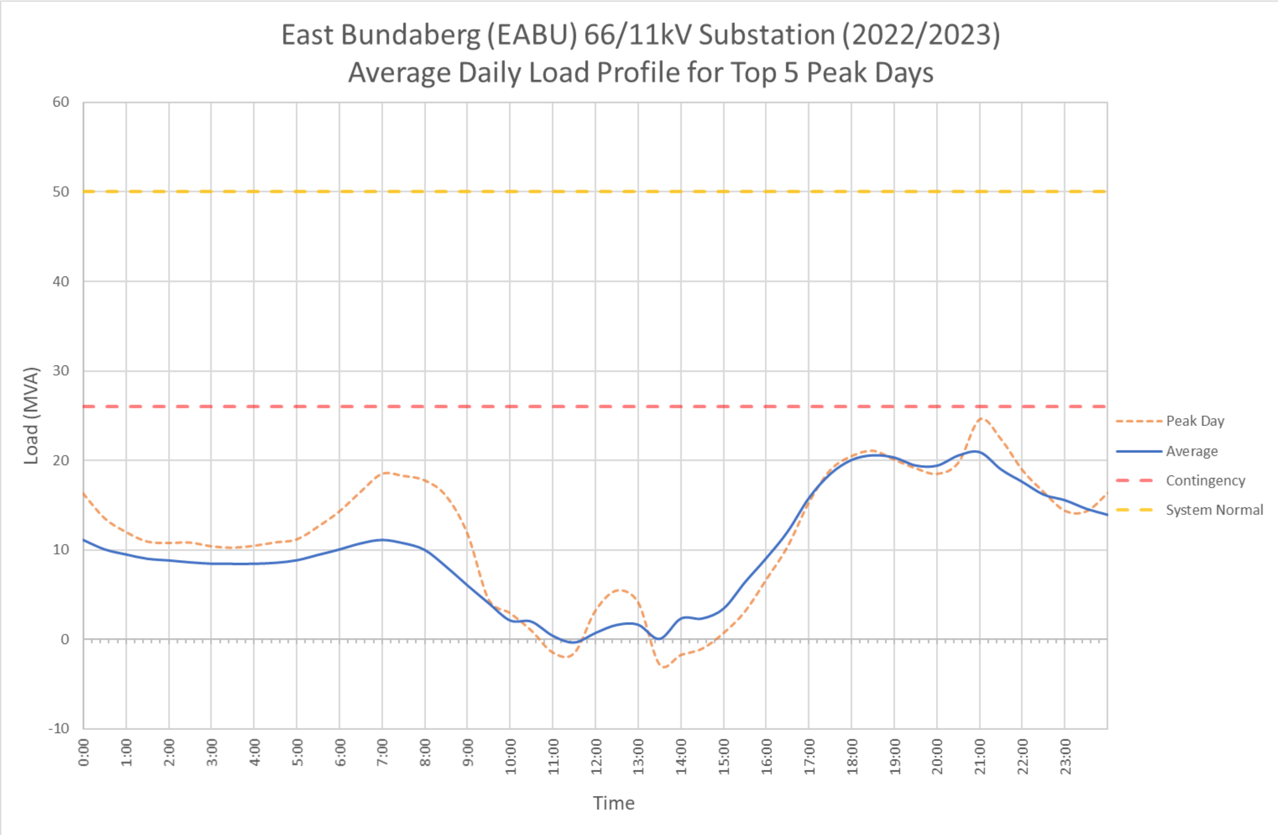

Figure 14: East Bundaberg Substation average peak weekday load profile (summer)

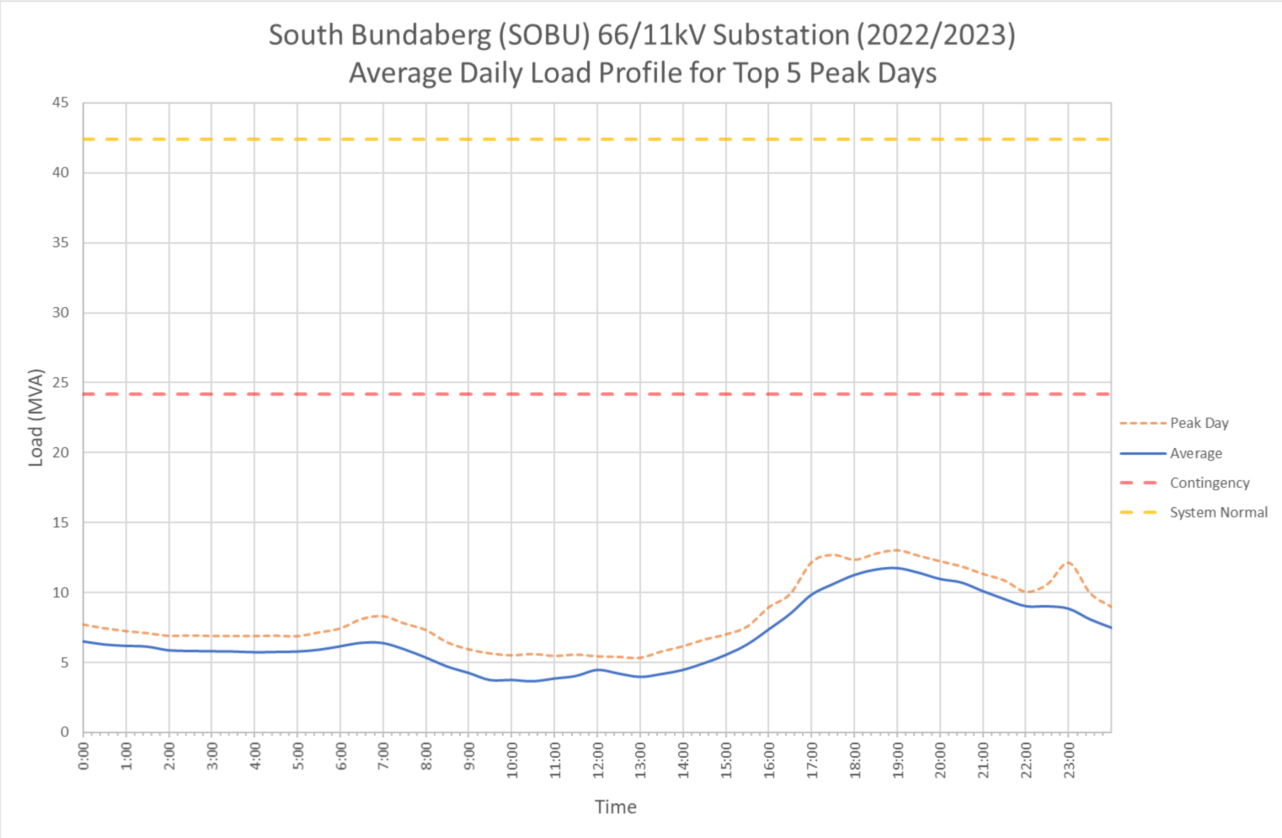

Figure 15: South Bundaberg Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 16, Figure 17, Figure 18 and Figure 19. The historical peak load for the past six years has also been included in the graph. Each graph also contains an indicative forecast loading if the major customer was to be supplied from each zone substation respectively. This indicative loading has only been included for the base load forecast to demonstrate the constraints at the existing zone substation 11kV supply. As can be seen, with the major customer connected upgrade works would be required at all substations except Bundaberg Central.

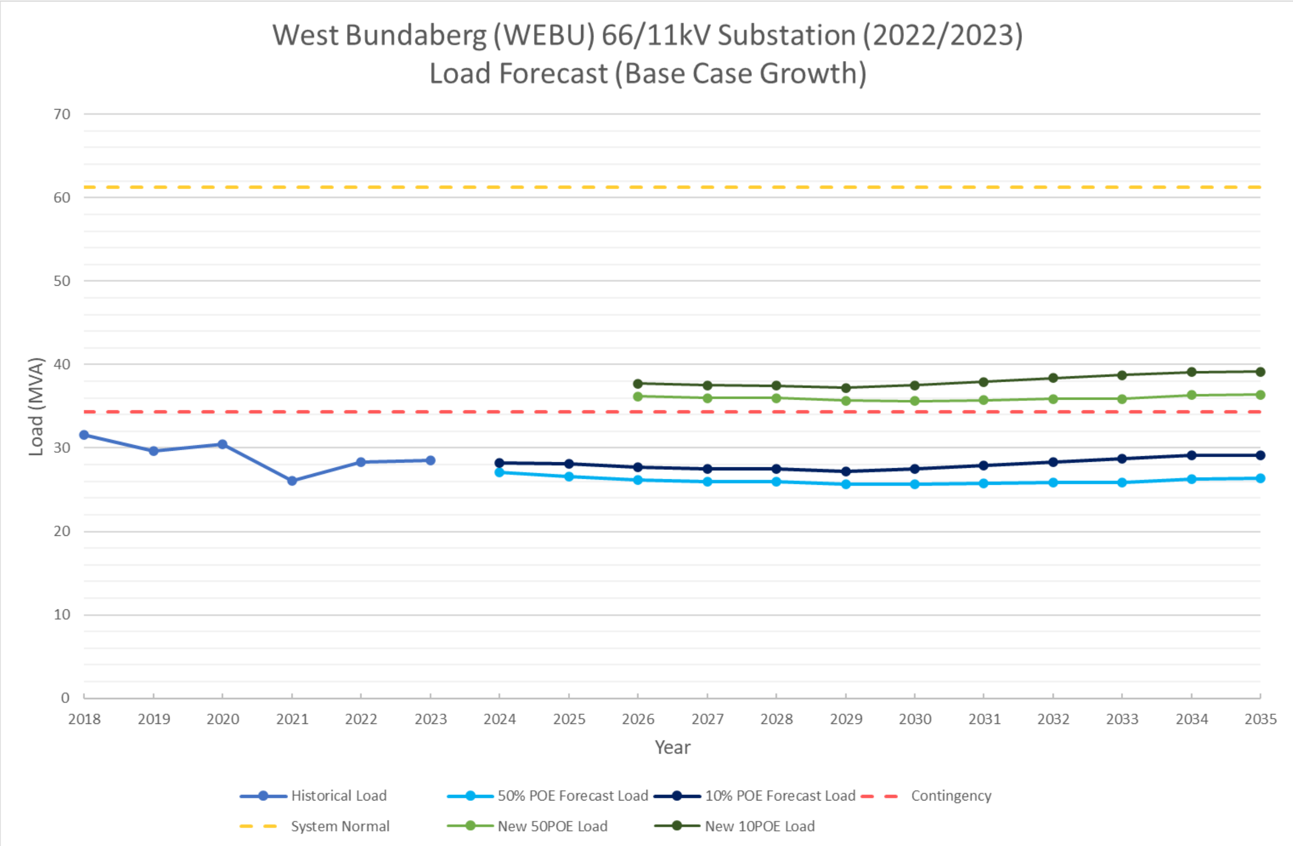

Figure 16: West Bundaberg Substation base case load forecast

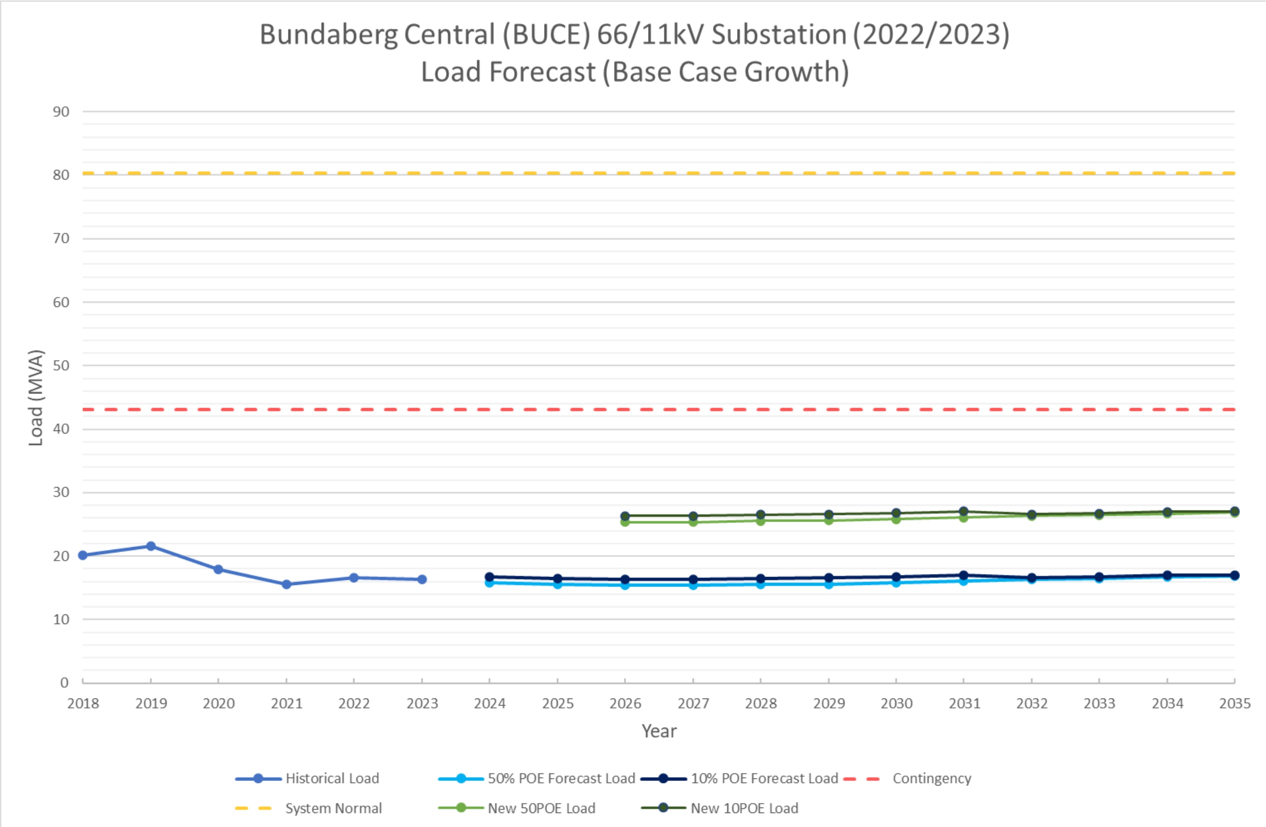

Figure 17: Bundaberg Central Substation base case load forecast

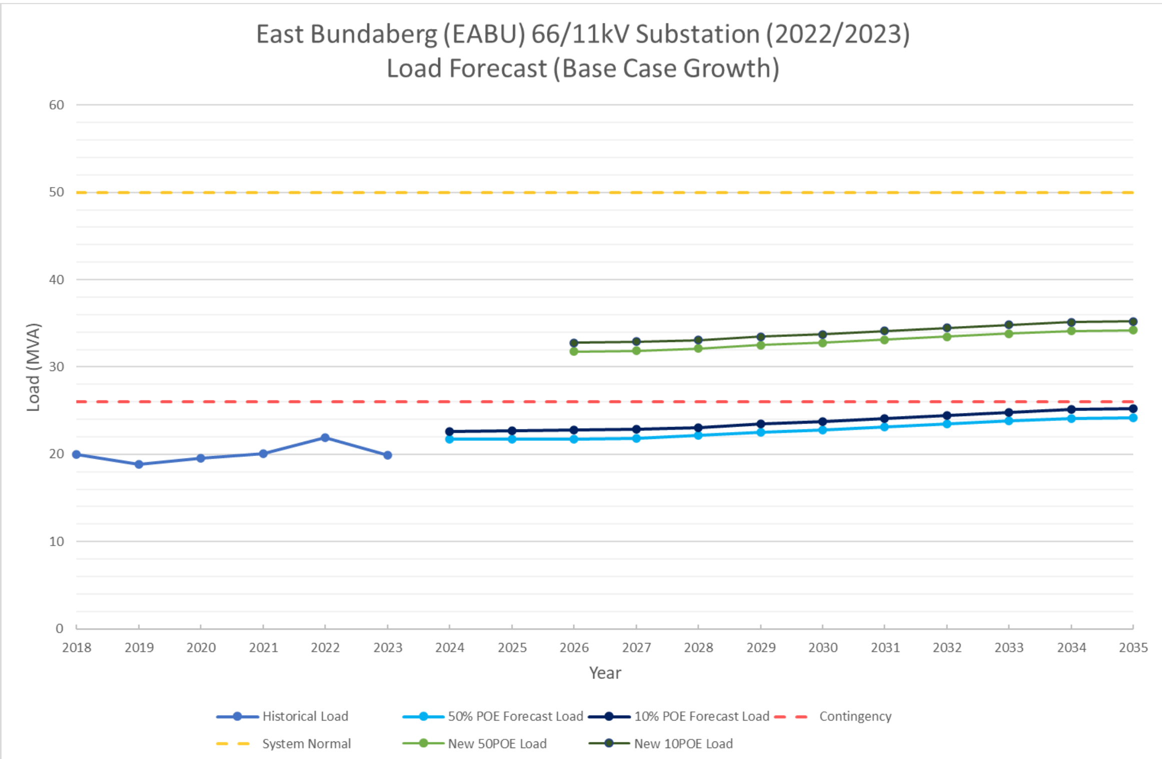

Figure 18: East Bundaberg Substation base case load forecast

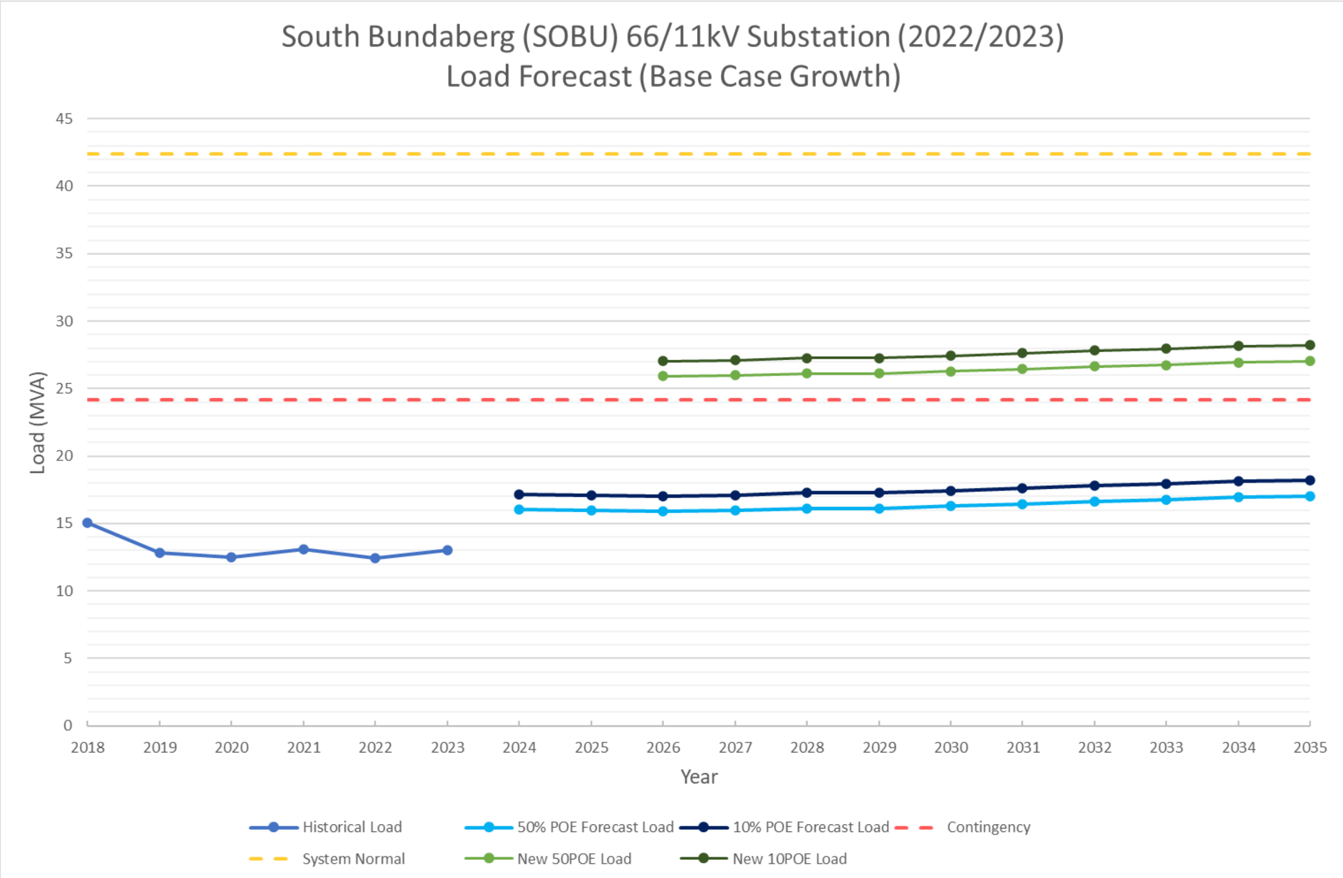

Figure 19: South Bundaberg Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 20, Figure 21, Figure 22, and Figure 23. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

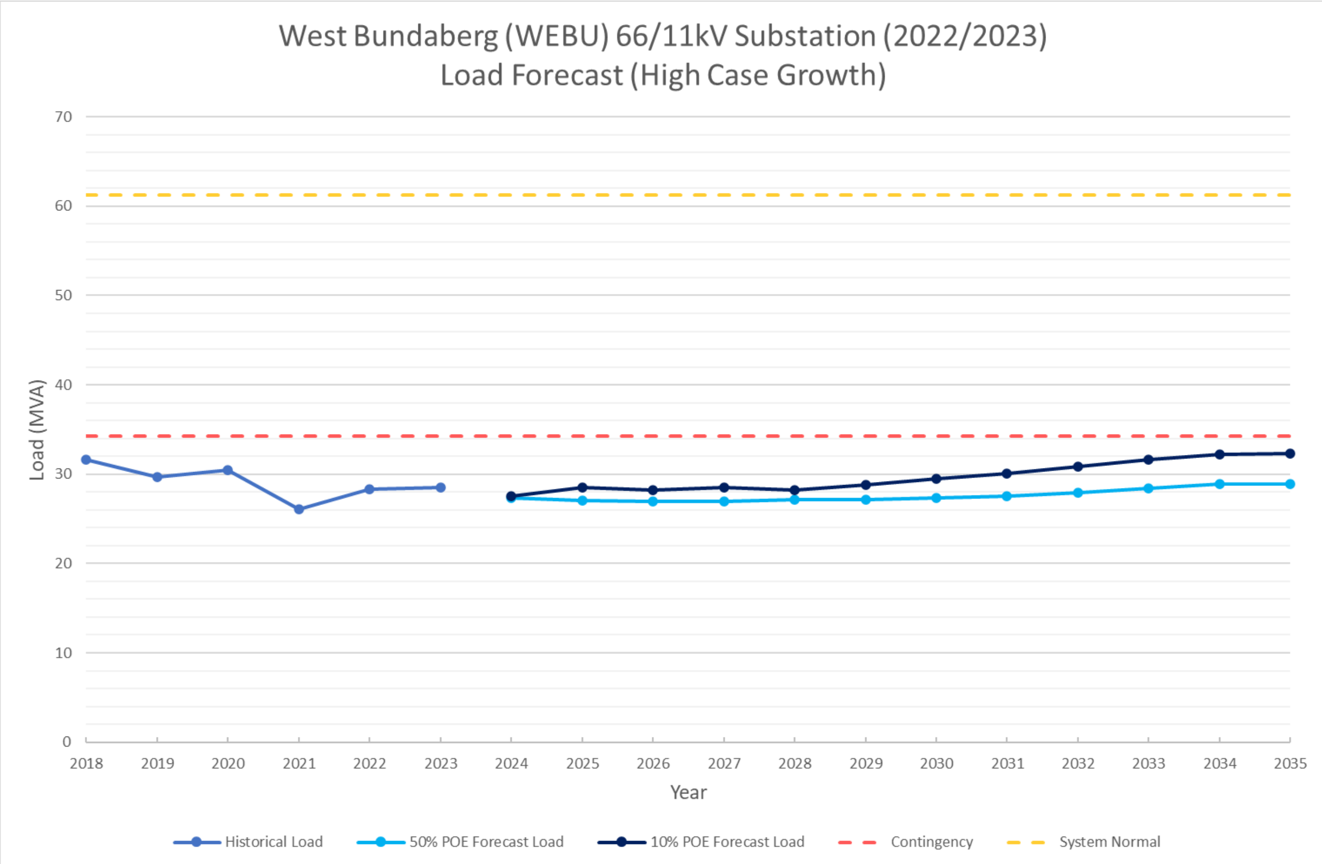

Figure 20: West Bundaberg Substation high growth load forecast

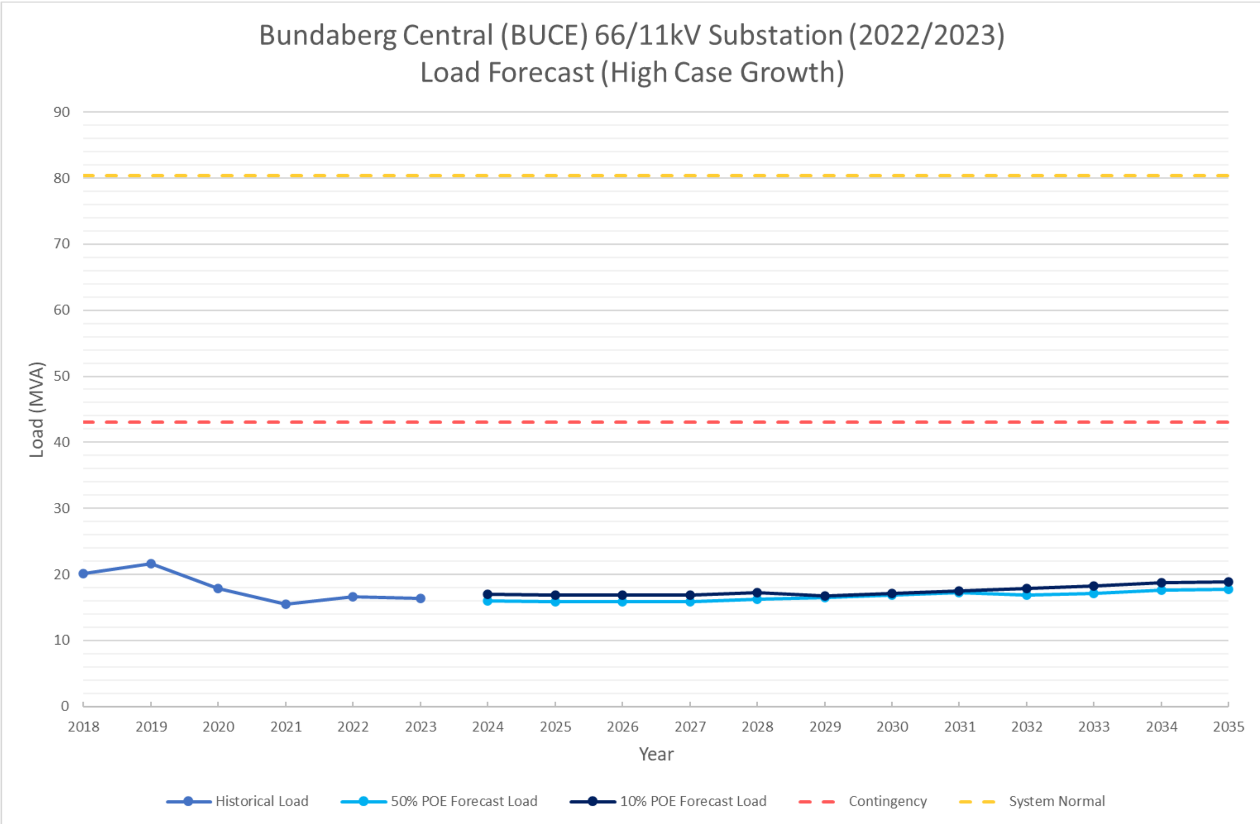

Figure 21: Bundaberg Central Substation high growth load forecast

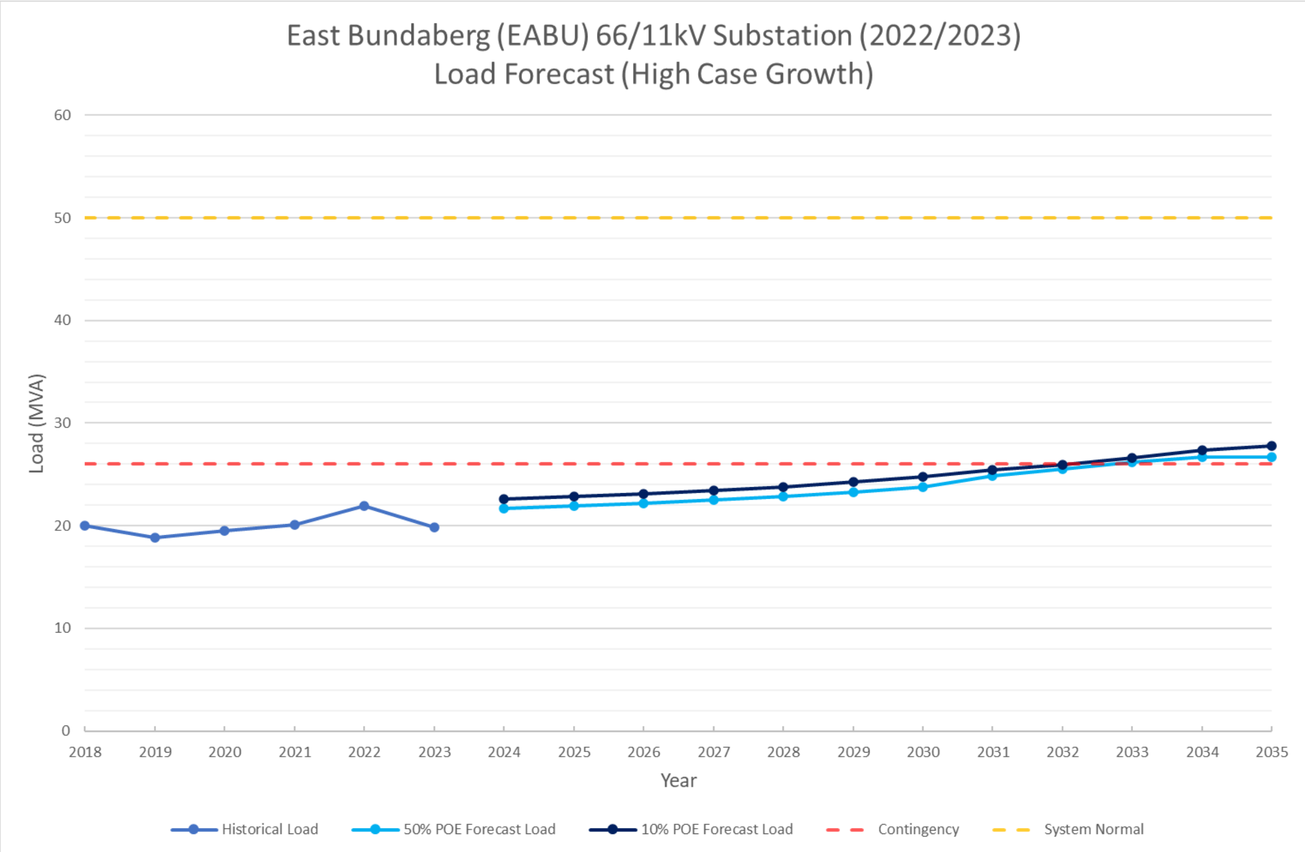

Figure 22: East Bundaberg Substation high growth load forecast

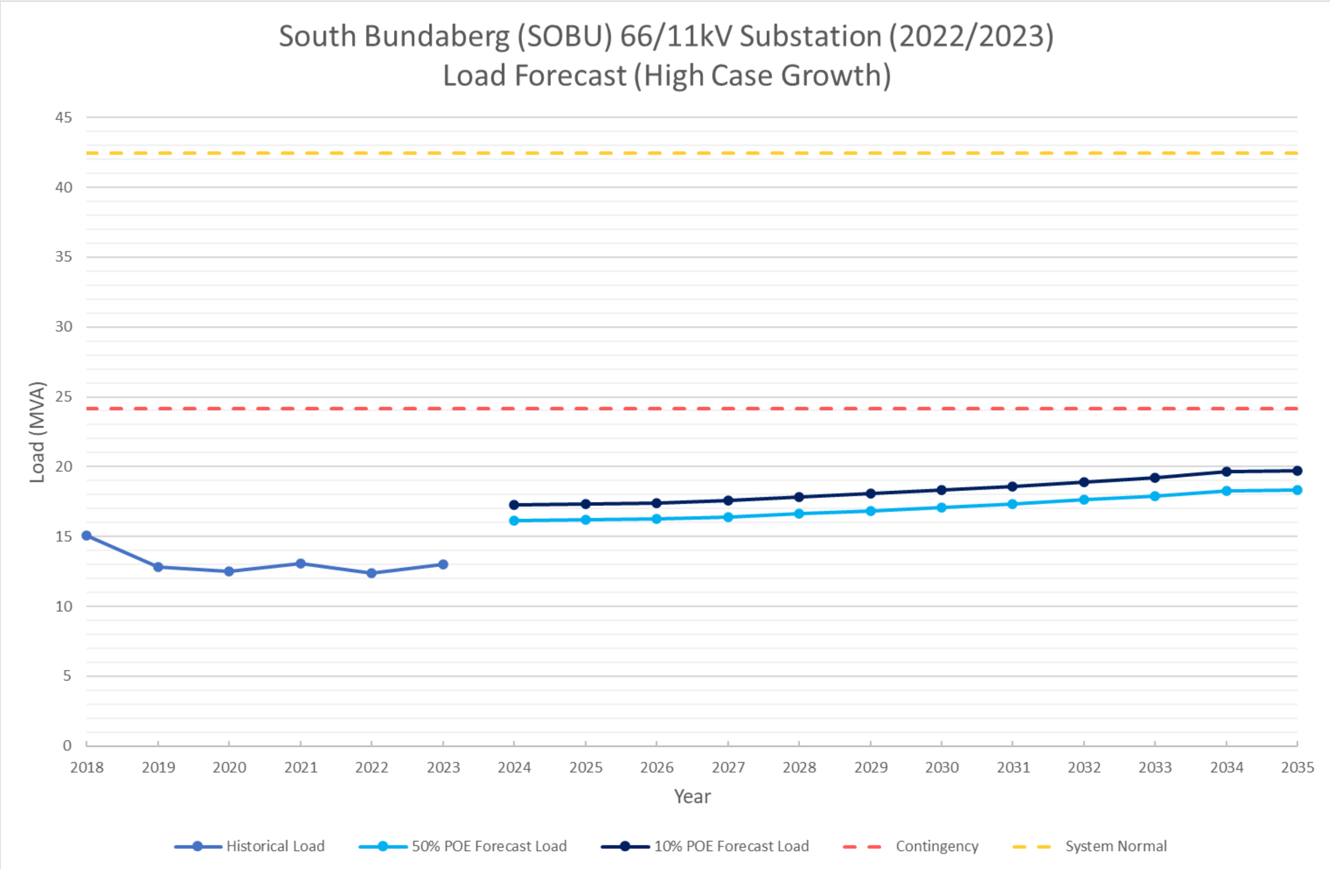

Figure 23: South Bundaberg Substation high growth load forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 24, Figure 25, Figure 26, and Figure 27. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

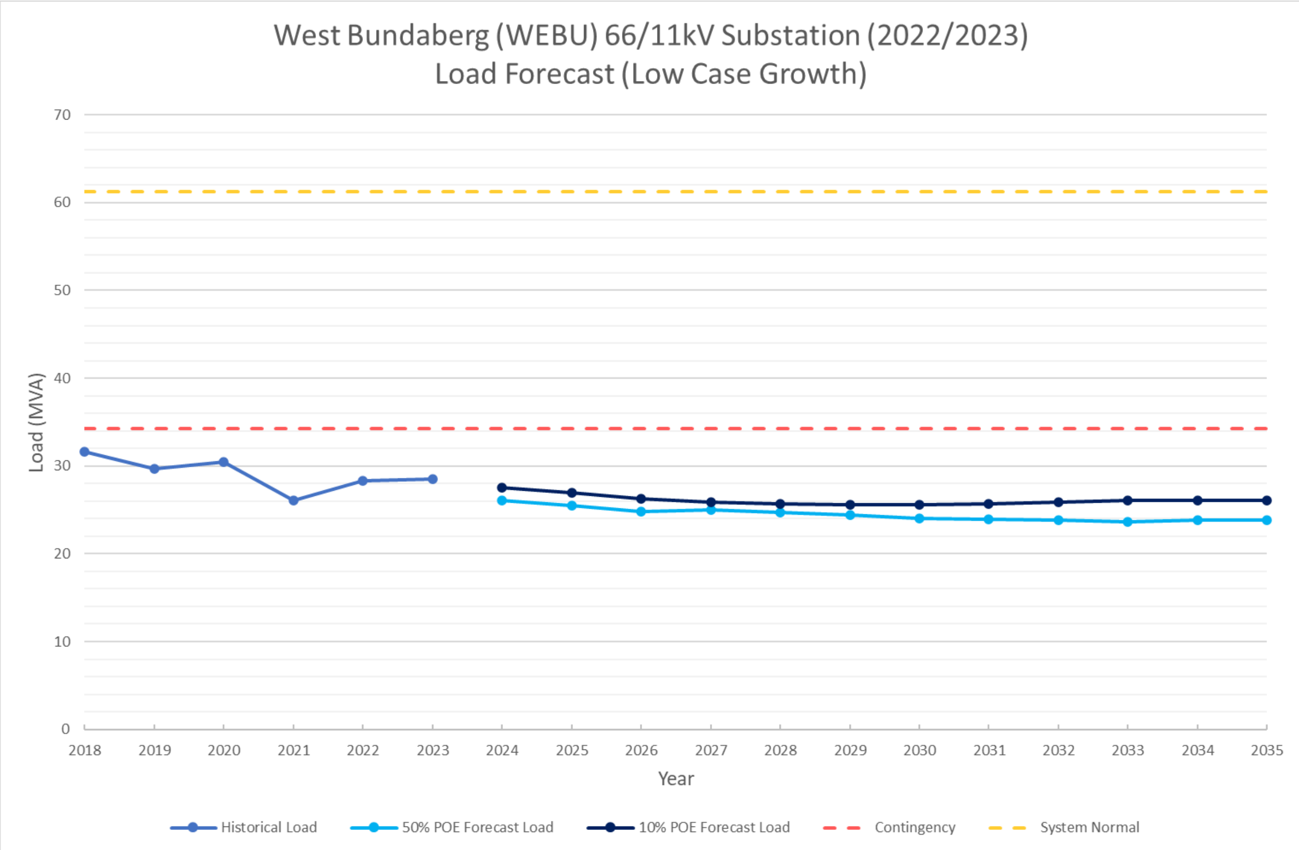

Figure 24: West Bundaberg Substation low growth load forecast

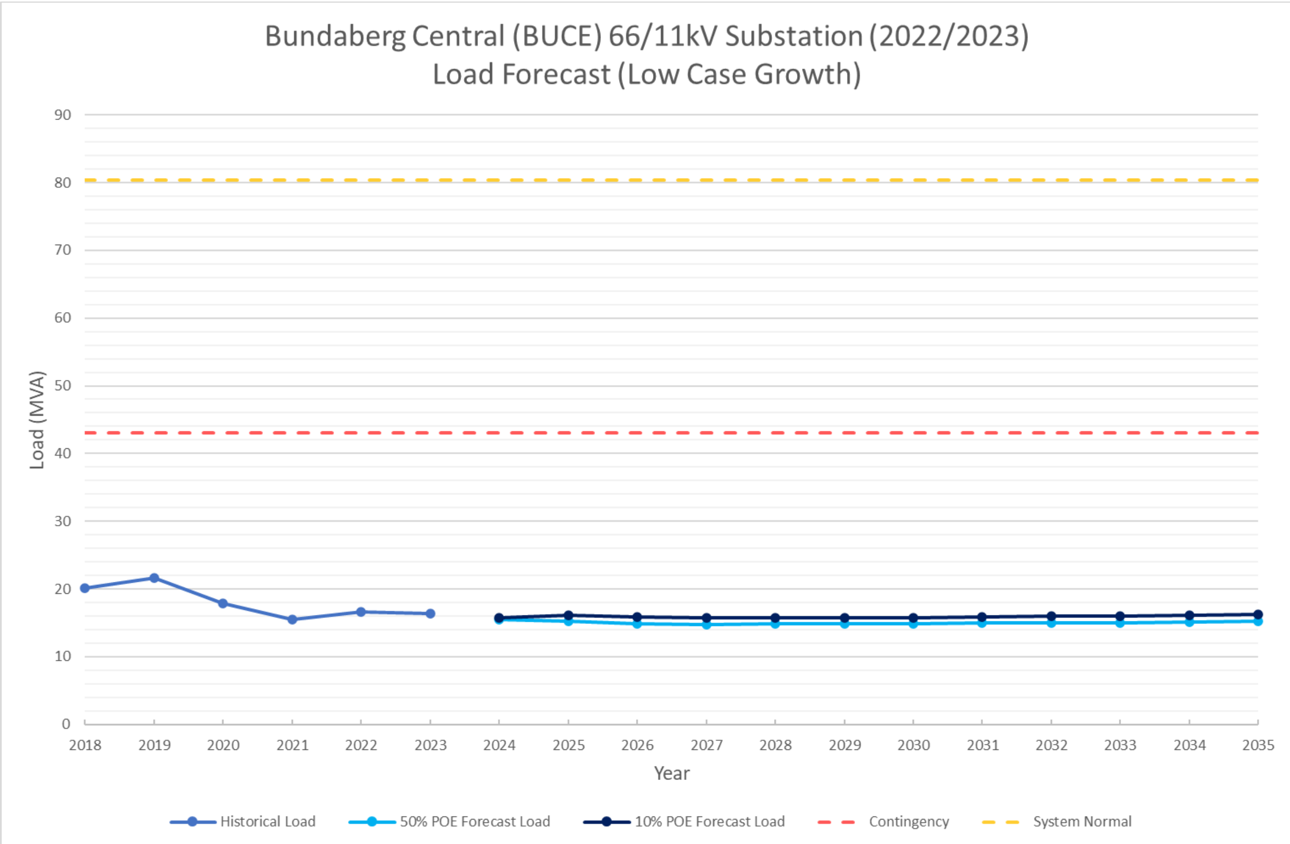

Figure 25: Bundaberg Central Substation low growth load forecast

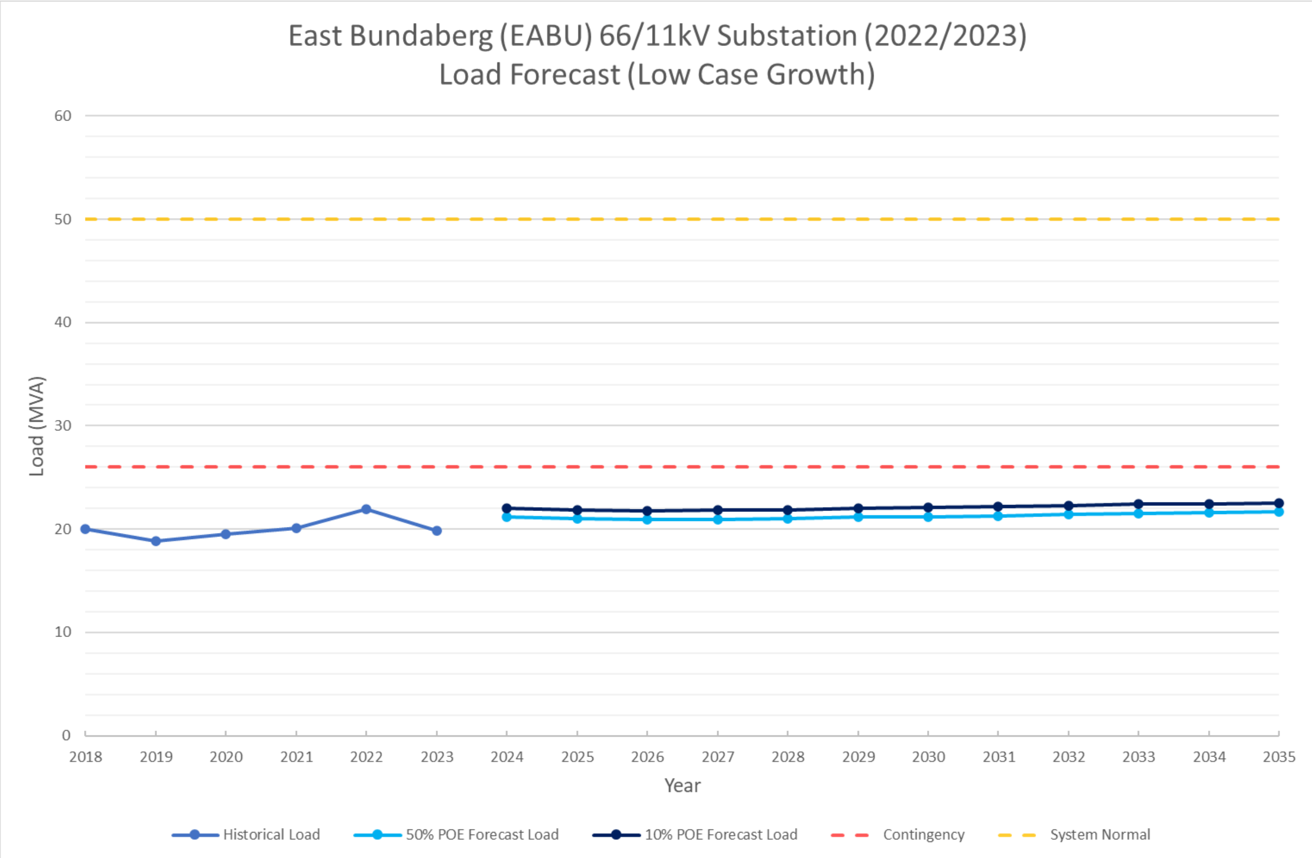

Figure 26: East Bundaberg Substation low growth load forecast

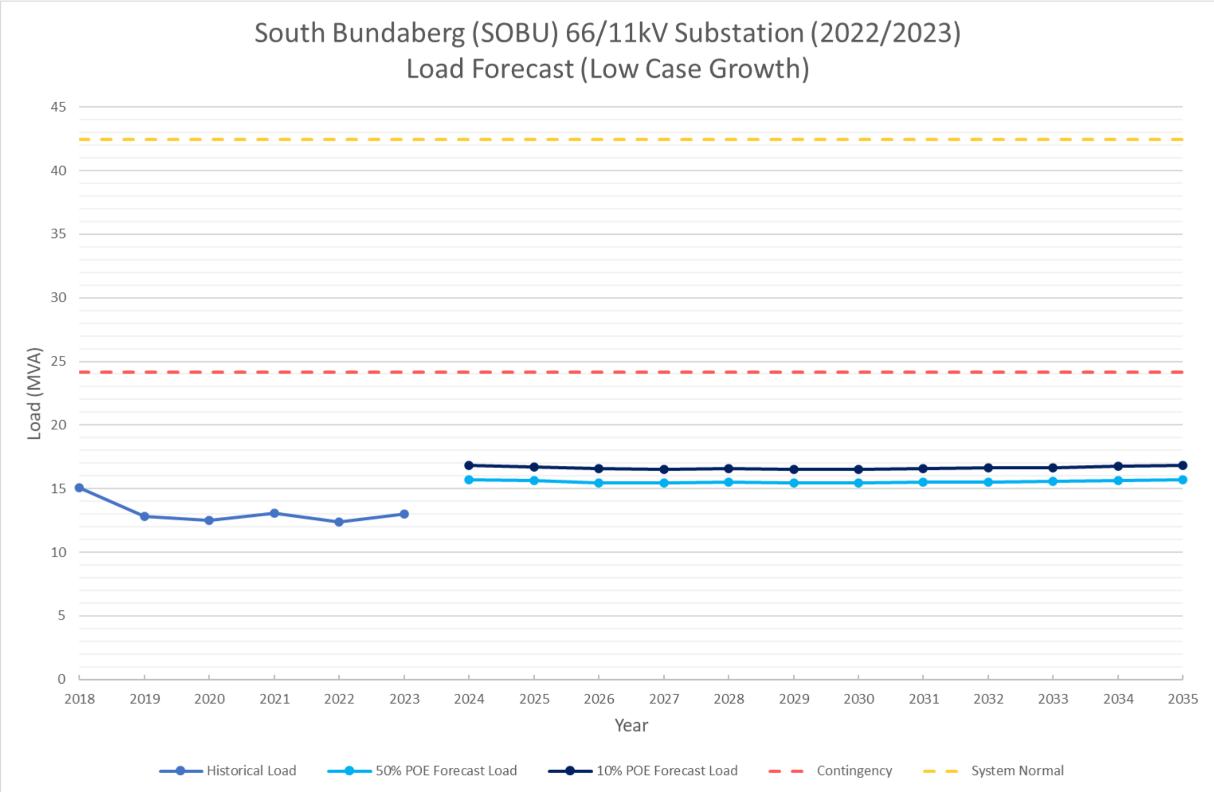

Figure 27: South Bundaberg Substation low growth load forecast

2.4. 66kV Sub-transmission Network

The 66kV network in the Bundaberg region emanates from Bundaberg (T20) Bulk Supply Substation and forms a ring between WEBU, BUCE, EABU and SOBU. M039 and M040 supply WEBU, which subsequently supplies Meadowvale (MEAD) and Gooburrum (GOOM) via M041, along with partial supply to BUCE via 6302 under system normal. This is an anticipated combined forecast load in 2034 of 67MVA. M036 supplies SOBU, which subsequently supplies EABU and partial supply to BUCE under system normal, along with BARG. The anticipated combined forecast load in 2034 is 65MVA.

It can be seen when comparing against values in Table 1 that the anticipated load in 2034 on M036 will exceed the rating of the feeder, without the major customer connected to the 11kV distribution network. With connection of the major customer at 11kV at any of the substation, SOBU, EABU or BUCE M036 would be overloaded and require augmentation as SCS costs. As shown in Section 1.3 only BUCE would have sufficient capacity to connect the customer without Zone substation augmentation.

It should be noted that the load flows through the Bundaberg Ring is complex and depends on network configuration. The above loading is indicative of the expected flows on the sub-transmission network under system normal, without the load of the major customer included.

Feeder Name	M040	M039	6302	6205	M037	M036
Voltage (kV)	66	66	66	66	66	66
Conductor Type	Taurus 19/4.75 AAC 1350	Taurus 19/4.75 AAC 1350	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Wasp 7/.173" (7/4.39) AAC 1350 (British)	Iodine 7/4.75 AAAC 1120
Design Temp	75	75	75	75	50	75
Length (m)						
***Ergon Energy* Climate Zone**	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special	Eastern & Coastal - Special
Summer Day A (MVA)	809 (92.5)	809 (92.5)	397 (45.4)	397 (45.4)	225 (25.7)	440 (50.3)
Summer Evening A (MVA)	906 (103.6)	906 (103.6)	436 (49.8)	436 (49.8)	311 (35.6)	480 (54.9)
Summer Night Morning A (MVA)	748 (85.5)	748 (85.5)	356 (40.7)	356 (40.7)	258 (29.5)	390 (44.6)
Winter Day A (MVA)	849 (97.1)	849 (97.1)	419 (47.9)	419 (47.9)	285 (32.6)	456 (52.1)
Winter Evening A (MVA)	799 (91.3)	799 (91.3)	381 (43.6)	381 (43.6)	295 (33.7)	417 (47.7)
Winter Night Morning A (MVA)	804 (91.9)	804 (91.9)	383 (43.8)	383 (43.8)	297 (34)	419 (47.9)

Table 1: 66kV Sub-transmission Network Ratings

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Connection of Major Customer

The primary driver for this project is the connection of a major customer in the Bundaberg Region by 2026. Due to commercial in confidence all details of the enquiry cannot be disclosed, however the information pertinent to this RIT-D is the connection of a load up to 10MW and requirement for an N-1 supply. The overall project includes both ACS and SCS costs components, however this RIT-D only focuses on the SCS component.

3.1.2. Zone Substation Limitations

As shown in section 2.3 the zone substations in the area have limited capacity and the connection of up to 10MW would exceed the substations N-1 capacity and induce a safety Net limitation, with the exception being BUCE.

3.1.3. Sub-transmission Network Limitations

As discussed in section 2.4 the sub transmission network between BUND (T20) and SOBU will have a limitation in 2034 based on the current load forecast without the connection of the major customer. This limitation had been on Ergon Energy horizon and tentative project placeholder for Bundaberg 66kV reinforcement had been proposed with completion dates between 2028-2030. This future project would implement a second 66kV feeder from BUND (T20) to SOBU to address the limitation.

3.2. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.2.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at WEBU, BUCE, EABU and SOBU Substations will be consistent with the base case forecast outlined in Section2.5.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history;
- known future developments (new major customers, network augmentation)

- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.2.2. Load Profile

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand and decreasing minimum demand.

4. TECHNICAL CHARACTERISTICS OF NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a non-network option would be required to comply with.

4.1. Size

To meet Ergon Energy's ongoing operational needs, it is expected that any alternate solution must provide stand-alone N-1 supply to the distribution network that supports a load up to the values listed in the table below.

Year	Demand Reduction Required
2026	16 MVA
2027	16 MVA
2028	16 MVA
2029	16 MVA
2030	17 MVA
2031	18 MVA
2032	18 MVA
2033	19 MVA
2034	19 MVA
2035	19 MVA
2036	19 MVA

Table 2: Demand reduction required

4.2. Location

The location where network support and load restoration capability will be measured / referenced is on the 66kV bus at South Bundaberg in 2026 and requirement to measure at EABU, WEBU and SOBU 11kV buses from 2033 onwards.

4.3. Timing

4.3.1. Implementation Timeframe

In order to ensure meet the major customer needs for connection non-network solution will need to be implemented by October 2026.

4.3.2. Time of Year and Duration

Given the requirement to connect a major customer a non-network solution would be required to supply 24 hours a day, 7 days a week for 365 days a year, while providing diverse N-1 capability.

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4.4. Compliance with Regulations and Standards

As a distribution network service provider (DNSP), Ergon Energy must comply with regulations and standards, including the Queensland Electricity Act and Regulation, Distribution Authority, National Electricity Rules and applicable Australian Standards.

These obligations must be taken in consideration when choosing a suitable solution to address the identified need in the Bundaberg region as discussed in this RIT-D report.

4.5. Longevity

Proposed non-network options will typically be required to provide solutions to the identified need for a period of at least 10 years.

4.6. Potential Deferred Augmentation Charge

The annual deferred augmentation charge associated with the identified need is approximately $440k per year.

4.7. Feasible vs Non-Feasible Options

4.7.1. Potentially Feasible Options

The identified need presented in this RIT-D is driven by the requirement to connect a major customer and supply up to 10MW load. As a consequence of the network option for the customer the future limitations on the 66kV network will be addressed along with providing future capacity for the Bundaberg region. Solutions must not only be cost-effective but address all of the identified needs.

No potentially feasible options have been identified which meet the identified need.

4.7.2. Options that are Unlikely to be Feasible

Without attempting to limit a potential proponent's ability to innovate when considering opportunities, some technologies / approaches are unlikely to represent a technically or financially feasible solution.

A non-exhaustive list of options that are unlikely to be feasible includes:

- Renewable generation not coupled with energy storage and/or dispatchable generation
- Unproven, experimental or undemonstrated technologies
- Options which don't provide diverse N-1 capacity.

Any option that is put forward will also need to be reviewed by the major customer to ensure all of their requirements are met by the proposed solution, along with the timeframes.

4.7.3. Timing of Feasible Options

In order to ensure compliance with Ergon Energy's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented by October 2026.

5. CREDIBLE OPTIONS ASSESSED

5.1. Assessment of Network Solutions

Ergon Energy has identified one credible network option that will address the identified need.

5.1.1. Option A: Development of Thabeban 66/11kV Substation

This option involves the development of a new greenfield 2 x 20/25MVA 66/11kV substation, which will be known as Thabeban (THAB). In order to provide diverse N-1 supply at the 66kV level THAB will be supplied via an approximately 4km 66kV feeder from BUND (T20) and an approximately 4km feeder from SOBU.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 28.

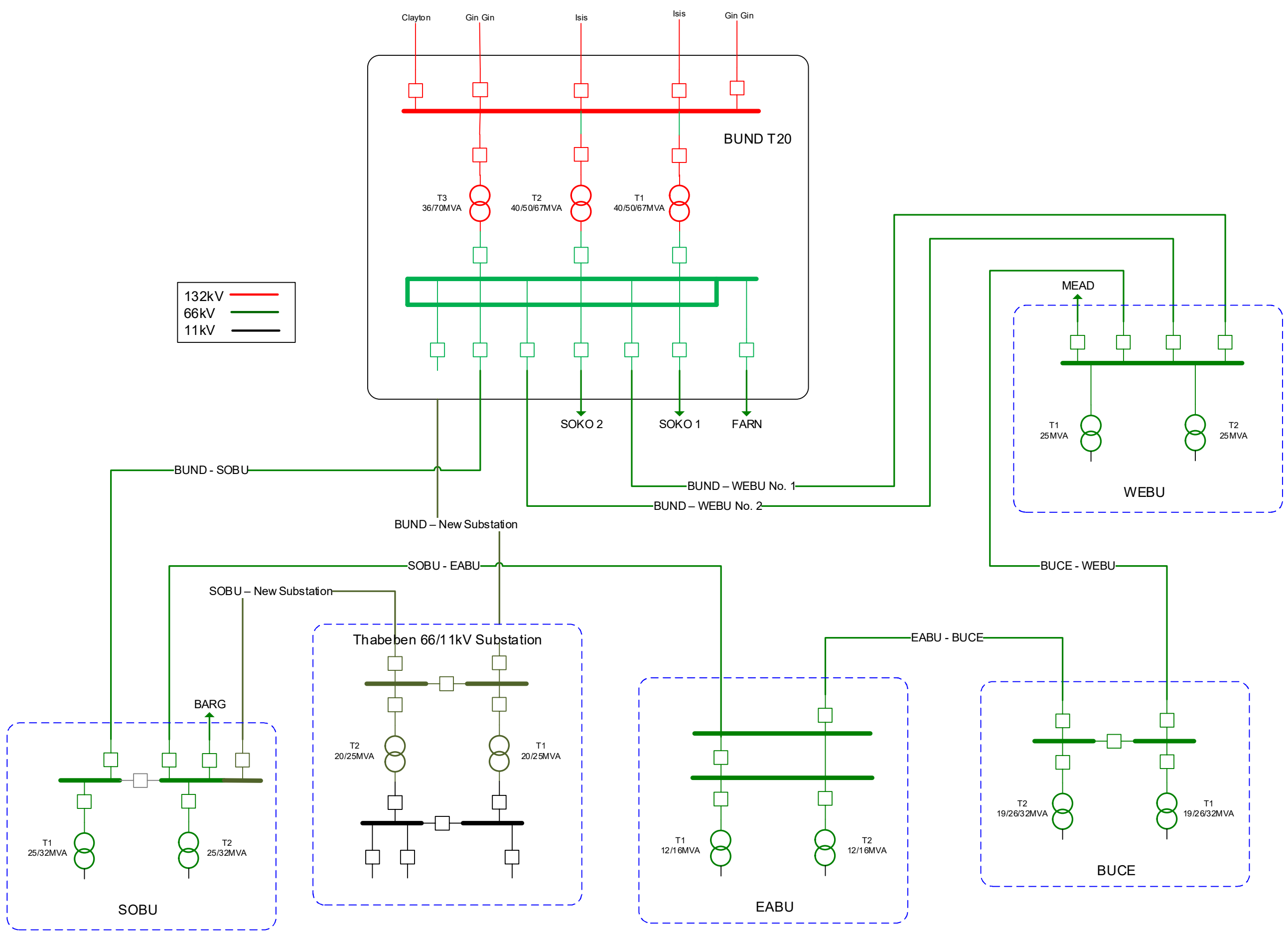


Figure 28: Option A proposed network arrangement (schematic view)

5.2. Assessment of Non-Network Solutions

Ergon Energy in assessing the major customer requirements for connection have not identified any full or partial non-network solutions.

Any credible options must be technically and commercially viable and must be able to be implemented in sufficient time (2026) to satisfy the identified need for the network to connect the major customer.

5.2.1. Demand Management (Demand Reduction)

Given the ultimate load requirement of up to 10MW and the need for high reliability and N-1 supply no demand management reduction methodologies have been identified that would provide a partial or total solution to the identified need.

5.2.2. Network Load Control

Across the four zone substations, WEBU, SOBU, EABU and BUCE the daily peak demand generally occurs between 5:00pm and 9:00pm.

There are 3,919 customers on tariff T31 and 14,193 customers on tariff T33 hot water load control (LC).

The Bundaberg Zone Substations LC signals are controlled from T020 Bundaberg Bulk Supply Substation (BUND). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable). Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Network load control does not address the identified need, especially once an additional 10MW load is added to the system.

5.2.3. Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed vs short time frame).

This option has also been assessed as technically not viable as it will not address the identified network requirement.

Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets. The requirements for the major customer are such that LSG will not provide a technically feasible solution.

Customer Solar Power Systems

The capacity of solar photo voltaic (PV) systems connected at each zone substation is 20,055kVA at WEBU, 20,330kVA at EABU, 6,796kVA at BUCE and 12,301kVA at SOBU.

The daytime peak between 9:00am and 3:00pm is reducing year on year in the Bundaberg region due to the integration of residential inverter energy systems. As such customer solar generation does not coincide with the peak load period. Residential Solar PV coupled with BESS may have the potential in the future to reduce peak demand, however when coupled with EV growth and charging profiles the peak may not be reduced substantially. However, it should be noted that reduction of the afternoon peak through BESS integration will not meet the requirements of identified need.

5.2.4. Non-Network Solution Summary

Ergon Energy has not identified any viable non-network solutions internally that will provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Bundaberg area to address the identified need.

5.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to develop a new greenfield 2 x 20/25MVA 66/11kV substation, Thabeban.

Upon completion of these works, identified needs listed in section 3 for the Bundaberg region will be addressed. The major customer can be connected with all of their requirements met, the 66kV network limitation is addressed and increase 11kV capacity in the region for future growth and connections. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure and providing future capacity for growth in the region.

The estimated direct SCS capital cost of this option has been estimated $15.41 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in late 2023 and construction completed by October 2026.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

6.1. Classes of Market Benefits Considered and Quantified

The class of market benefit that were considered to be material for this RIT-D assessment was:

- Changes in Load Transfer Capacity and the capacity of Embedded generators to take up load
- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

6.1.1. Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load

By establishing a new zone substation in the Bundaberg region with a duplicated 66kV connection between BUND (T020) and SOBU there will be an increase in the load transfer capability in the Bundaberg ring. As 11kV feeders are established from THAB 66/11kV substation it will provide additional transfer capacity to the zone substations in the area. These have been added as benefits in the NPV and calculated as a VCR benefit based on the ability to transfer load in a contingency.

6.1.2. Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages

The credible options presented in this RIT-D assessment do not include any involuntary load shedding. Using a reasonable forecast of the value of electricity distribution services to customers, Ergon Energy has undertaken an analysis and consider the changes to be material.

Involuntary load shedding is where a customer’s load is interrupted from the network without their agreement or prior warning. Ergon Energy has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required assuming the credible option is completed multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ergon Energy has applied a VCR estimate of $41.83/kWh, which has been derived from the AER 2022 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

Customer export Curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the Bundaberg supply area.

6.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure
- Changes in network losses
- Option value
- Other class of Market Benefit

6.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the [insert location here] area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

6.2.2. Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

6.2.3. Differences in Timing of Expenditure

The credible options included in this RIT-D assessment is not expected to affect the timing of other distribution investments for unrelated identified needs.

6.2.4. Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[1].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

6.2.5. Other Class of Market Benefit

Ergon Energy has not identified any other relevant class of market benefit for this RIT-D.

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The Regulatory Investment Test for Distribution requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the National Electricity Market.

Accordingly, a base case Net Present Value (NPV) comparison of the alternative development options has been undertaken. A sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered.

7.2. Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating and maintaining the options as well as expected costs of compliance and administration associated with each option.

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated WACC. The interest on borrowings is

[1] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A6. Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

included in the Total Project Cost for which approval is being sought as it represents a legitimate cost of network augmentation.

Table 3 outlines the major parameters analysed within the sensitivity analysis which was undertaken to assess the impact of changing parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
WACC	2.72%	2.5%	5%
Project Costs	Standard estimates	-40%	+40%
Project Costs	Preferred option estimates	-20%	+20%
Opex Costs	Calculated Opex	-10%	+10%

Table 3: Economic parameters and sensitivity analysis factors

7.3. Scenarios Adopted for Sensitivity Testing

A sensitivity analysis was conducted on the base case to establish the option that remained the lowest cost option in the scenarios considered. In this instance, the scenarios that have been considered are:

- **Medium demand** – under this scenario the existing load remains around the same as it currently is. This is consistent with the base case load forecast provided in SIFT.

7.4. Net Present Value (NPV) Results

Although there was only one credible option identified which meets all the identified needs, including N-1 supply to a major customer; given that the SCS component cost of the project will also address the future 66kV limitation and provide future 11kV capacity, alternate options for meeting these limitations have been shown in the NPV.

This is to provide transparency and to demonstrate that the SCS investment provides the most prudent investment in the network, meeting the present and future needs. However, it should be noted that options B and C do not address all of the identified needs, only future network limitations.

An overview of the initial capital cost and the base case NPV results are provided in Table 4.

Option	Option Name	Rank	PV of Capex ($ real)	PV of Opex ($ real)	Net Economic Benefit ($ real)
A	Build Thabeban 2 x 20/25MVA Substation	1	$15,406,000	$6,983,000	$62,438,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	$22,668,000	$10,253,000	$62,438,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	2	$19,069,000	$8,508,000	$61,945,000

Table 4: Base case NPV ranking table

A sensitivity analysis was conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered. Table 5 provides the results of the sensitivity analysis.

Option Number	Option Name	Weighted Rank	Average NPV	Maximum NPV	Minimum NPV
A	Build Thabeban 2 x 20/25MVA Substation	1	$38,664,000	$40,128,000	$37,088,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	3	$27,996,000	$31,265,000	$24,641,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	2	$32,739,000	$35,350,000	$29,780,000

Table 5: Scenario Analysis - Comparison of Options

Table 6 shows the NPV for the upper and lower WACC and demonstrates that under all scenarios option A is the preferred option.

Option Number	Option Name	2.00% WACC	5.00% WACC
A	Build Thabeban 2 x 20/25MVA Substation	$52,087,000	$17,605,000
B	SOBU TR Upgrade + 66kV Upgrade + THAB 2050	$40,865,000	$8,489,000
C	SOBU 66kV in 2026 + SOBU Upgrade in 2040 + THAB 2050	$45,388,000	$14,604,000

Table 6: WACC sensitivity Analysis for Base Case Forecast

Based on the detailed economic assessment, Option A is considered to provide the optimum solution to address not only the immediate identified need but also the forecast network limitations and is therefore the recommended development option.

7.5. Selection of Preferred Option

Ergon Energy's preferred option is Option A, to develop Thabeban 66/11kV substation with 2 x 20/25MVA transformers.

Upon completion of these works, identified needs listed in section 3 for the Bundaberg region will be addressed. The major customer can be connected with all of their requirements met, the 66kV network limitation is addressed and increase 11kV capacity in the region for future growth and connections. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure and providing future capacity for growth in the region.

The estimated direct SCS capital cost of this option has been estimated $15.41 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in late 2023 and construction completed by October 2026.

7.6. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. SUBMISSION AND NEXT STEPS

8.1. Submissions from Solution Providers

Ergon Energy invites written submissions to address the identified need in this report from registered participants and interested parties.

Ergon Energy will not be legally bound in any way or otherwise obligated to any person who may receive this RIT-D report or to any person who may submit a proposal. At no time will Ergon Energy be liable for any costs incurred by a proponent in the assessment of this RIT-D report, any site visits, obtainment of further information from Ergon Energy or the preparation by a proponent of a proposal to address the identified need specified in this RIT-D report.

The RIT-D process is aimed at identifying a technically feasible non-network alternative to the internal option that has greater net economic benefits. However, the selection of the solution provider to implement the preferred option will be done after the conclusion of the Final Project Assessment Report (FPAR) and in accordance with Ergon Energy's standards for procurement.

Submissions in writing are due by 4pm on the **25 October 2023** and should be lodged to demandmanagement@ergon.com.au

8.2. Next Steps

Following Ergon Energy's consideration of submissions received in response to this report, the preferred option, and a summary of and commentary on any submissions received will be included as part of the Final Project Assessment Report (FPAR). The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to publish the FPAR no later than **30 October 2023**. Ergon Energy will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Ergon Energy.

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution(s) to ensure timely connection of the major customer.

Please note that at the conclusion of the Final Project Assessment Report (FPAR), for Ergon Energy to act on a submission from a non-network proponent, Ergon Energy will need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Ergon Energy to ensure timely completion of the project. Failure to enter into a contract within a satisfactory timeframe will result in Ergon Energy reverting to the next preferred credible option identified as part of the preferred option published in the FPAR.

Step 1	Publish Notice of No Non-Network Options Report	Date Released: **8 September 2023**
Step 2	Release of Draft Project Assessment Report (DPAR) (This Report)	Date Released: **11 September 2023**
Step 3	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 4	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **30 October 2023**
Ergon Energy reserves the right to revise this timetable at any time. The revised timetable will be made available on the Ergon Energy RIT-D website.		

Ergon Energy will take all reasonable efforts to maintain the consultation schedule listed above. Due to various circumstances the schedule may change, however, up-to-date information will be available on the Ergon Energy website.

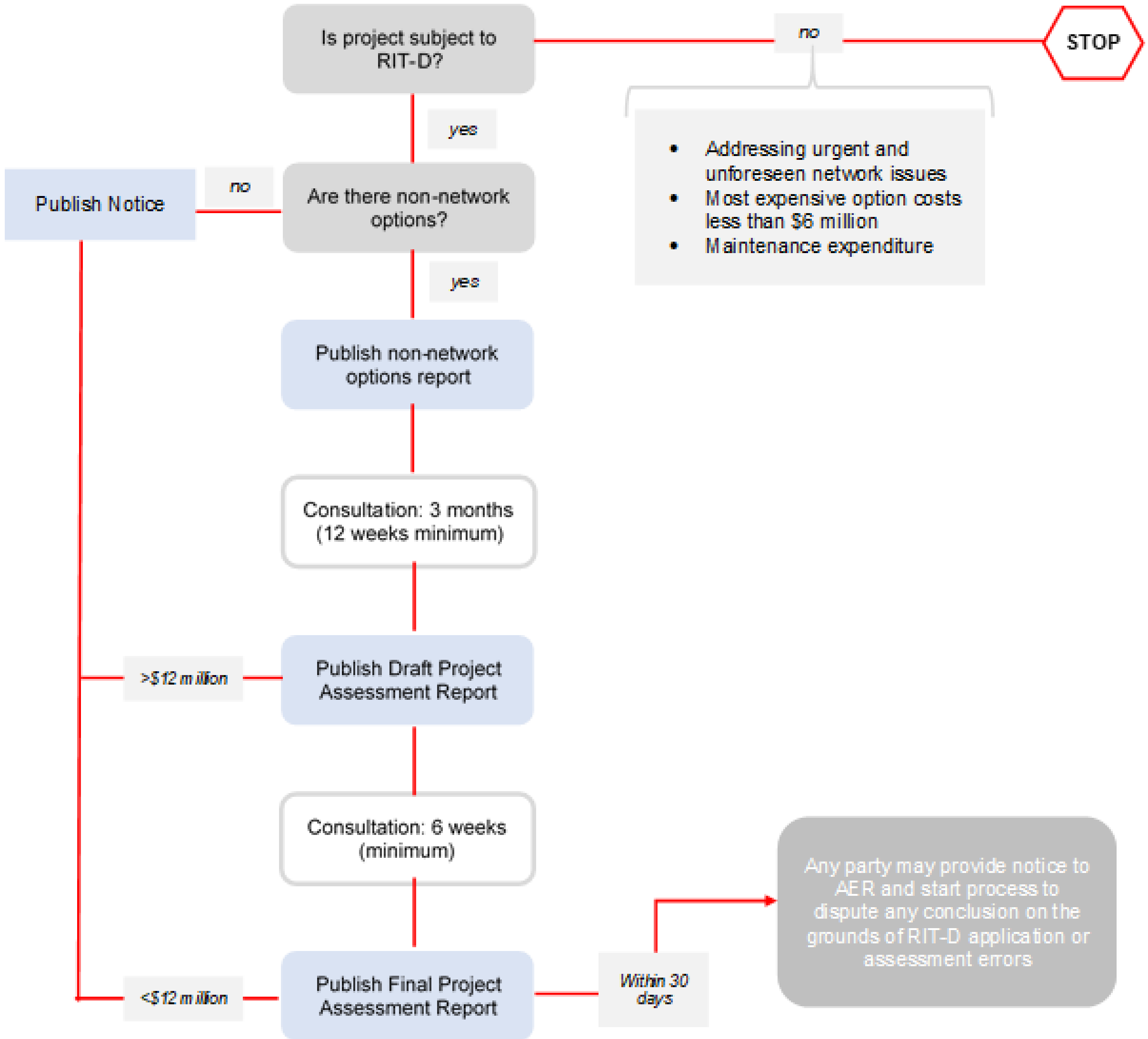
During the consultation period, Ergon Energy will review, compare and analyse all internal and external solutions. Detailed economic options analysis and comparisons of expected market benefits will be undertaken during this time. At the end of the consultation and review process Ergon Energy will publish a final report which will detail the most feasible option and proceed to implement that option.

9. COMPLIANCE STATEMENT

This Draft Project Assessment Report complies with the requirements of NER section 5.17.4(j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the NNOR;	N/A
(4) a description of each credible option assessed	5
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	7
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	6.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7.4
(10) the identification of the proposed preferred option	5.3 & 7.5
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	7.5 & 7.6
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	1.2

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.