Regulatory Investment Test for Distribution (RIT-D)

Addressing increased customer demand in the Bohle Plains Area

Options Screening Report

22 October 2024

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

The Northern Beaches and Bohle Plains areas have been the main development areas in the Townsville region over the past few years with several new subdivisions under development including Sanctum, Mt Low, Kingston Park, North Shore, Greater Ascot, Cosgrove, Liberty Rise, Kalynda Chase, Harris Crossing, Mount Margaret and The Reserve. Due to the projected growth in this area Ergon Energy strategically acquired future substation sites at Mt Low and Bohle Plains to cater for the future electrical supply requirements.

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. The DG-07, DG-10, BO-05 and BO-10 11kV feeders supply 4,181 predominantly residential customers and there has been significant growth in customer numbers and load due to the developments in the area.

Due to the forecasted increase in customer demand, Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (Safety Net requirements imposed in its Distribution Authority issued under the *Electricity Act 1994* (Qld)). The forecast loading for the substations and distribution feeders supplying the Bohle Plains area is expected to exceed the available N-1 substation and feeder capacity within the next 10 years. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements. The typical repair times for a substation transformer fault or an underground cable fault would exceed the 24 hour period required to restore supply to all customers.

Local Renewable Energy Zones – Townsville

In June 2024, the Minister for Energy and Clean Economy Jobs, The Honourable Mick de Brenni, announced the Local Renewable Energy Zone for Townsville. The Bohle Plains area falls within the Townsville Local Renewable Energy Zone (LREZ).

The Local Renewable Energy Zone (LREZ) pilot being established in Townsville aims to put the community at the centre of the renewable energy transition by helping the community generate more renewable energy, store it, share it and coordinate it across the local electricity infrastructure that already exists. LREZs will maximise the value of local customer energy resources like solar, storage, EVs, hot water and other appliances by coordinating them with our network and network energy storage across entire communities to take full advantage of the scale and value of the roof tops of Queenslanders. The LREZ pilot project will see the deployment of up to 8.4MW/18.8MWh of battery storage and support up to an additional 2.8MW of solar PV, and 0.9MW of demand management across nearly 550 residential and commercial customer sites starting from January 2025. More information is available at https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries/local-renewable-energy-zone-lrez-pilot.

The LREZ is a trial project and despite having some clear targets for rooftop solar, energy storage and demand management, it is not yet clear whether those LREZ objectives will be sufficient to completely resolve the forecast identified constraints that this Bohle Plains Options Screening Report outlines. For that reason, this screening report and the steps required as part of the Regulatory Investment Test for Distribution will occur concurrently to the LREZ project. The project teams for both this project and LREZ project will continue to collaborate throughout the life of both projects to ensure that the most appropriate solution or mix of solutions is deployed to ensure that Ergon Energy Network can continue to meet Safety Net requirements and to provide electricity to the consumers in the Bohle Plains supply area in a reliable, safe and cost-effective manner.

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 meet Safety Net requirements and to provide electricity to the consumers in the Bohle Plains supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D. This Options Screening Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(e) of the NER and seeks information from all interested parties, as listed in clause 5.17.4(a) of the NER, about alternative potential credible options to address the identified need.

Submissions in writing are due on the **31 January 2025** 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

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1. INTRODUCTION

This Options Screening Report has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(e) of the NER.

This report represents the first 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 Bohle Plains 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 limitations of the distribution network supplying the Bohle Plains area.
- Identifies the need which Ergon Energy is seeking to address, together with the technical characteristics of the identified need and the assumptions used in identifying and quantifying that need.
- Describes the potential credible options that Ergon Energy currently considers may address the identified need, including for each:
    - A technical definition or characteristics of the option;
    - The estimated construction timetable and commissioning date; and
    - The total indicative cost (including capital and operating costs).
- Sets out the technical characteristics that a non-network option or SAPS option would be required to deliver in order to address the identified need.
- Information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a proposal for consideration. This report is an invitation to registered participants and interested parties to make submissions on potential credible options to address the identified need.

1.2. General Terms and Conditions

1. By publishing this Options Screening Report, Ergon Energy is under no obligation whatsoever to review, discuss, select or enter into any agreement with any proponent who may submit a proposal.

2. Proponents will be responsible for all costs associated with the preparation and assessment of providing a proposal in response to this Options Screening Report including but not limited to any site visits and responding to further information requests made by Ergon Energy in order to assist Ergon Energy in its assessment of the proposal.
3. When evaluating a proposal, Ergon Energy will follow the NER and RIT-D Guidelines (available on the AER website). Further, Ergon Energy will follow the process as described in Ergon Energy's Industry Engagement Document (IED) a copy of which can be found at the following link.
4. Ergon Energy may combine all or parts of separate proposals for the purposes of evaluation where this may lead to a more efficient outcome than the separate proposal or option. Proponents should indicate in their proposal whether they wish to have their proposals or options considered in isolation or in combination with other proponents proposals.
5. Ergon Energy will publicly announce the outcome of the evaluation process. This announcement will be published on Ergon Energy's website and will include a summary of all submissions. Ergon Energy views the information provided as part of submissions to the Options Screening Report as Commercial in-Confidence and as such will not publish the capital and operating costs associated with a proponent's proposal.

1.3. Contact Details

Submissions in writing are due by 4pm on **31 January 2025** and should be lodged to demandmanagement@ergon.com.au.

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2. BACKGROUND

2.1. Geographic Region

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. DAGL is supplied from T092 Dan Gleeson 132/66kV Bulk Supply Substation which is located on the same site. The other two main substations in the Townsville West area BOHL and Black River (BLRI) 66/11kV substation are normally supplied from two 66kV feeders, the DAGL-BOHL 66kV feeder from T092 Dan Gleeson 132/66kV Bulk Supply Substation and the GARB-BOHL 66kV feeder from T046 Garbutt Bulk Supply Substation.

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

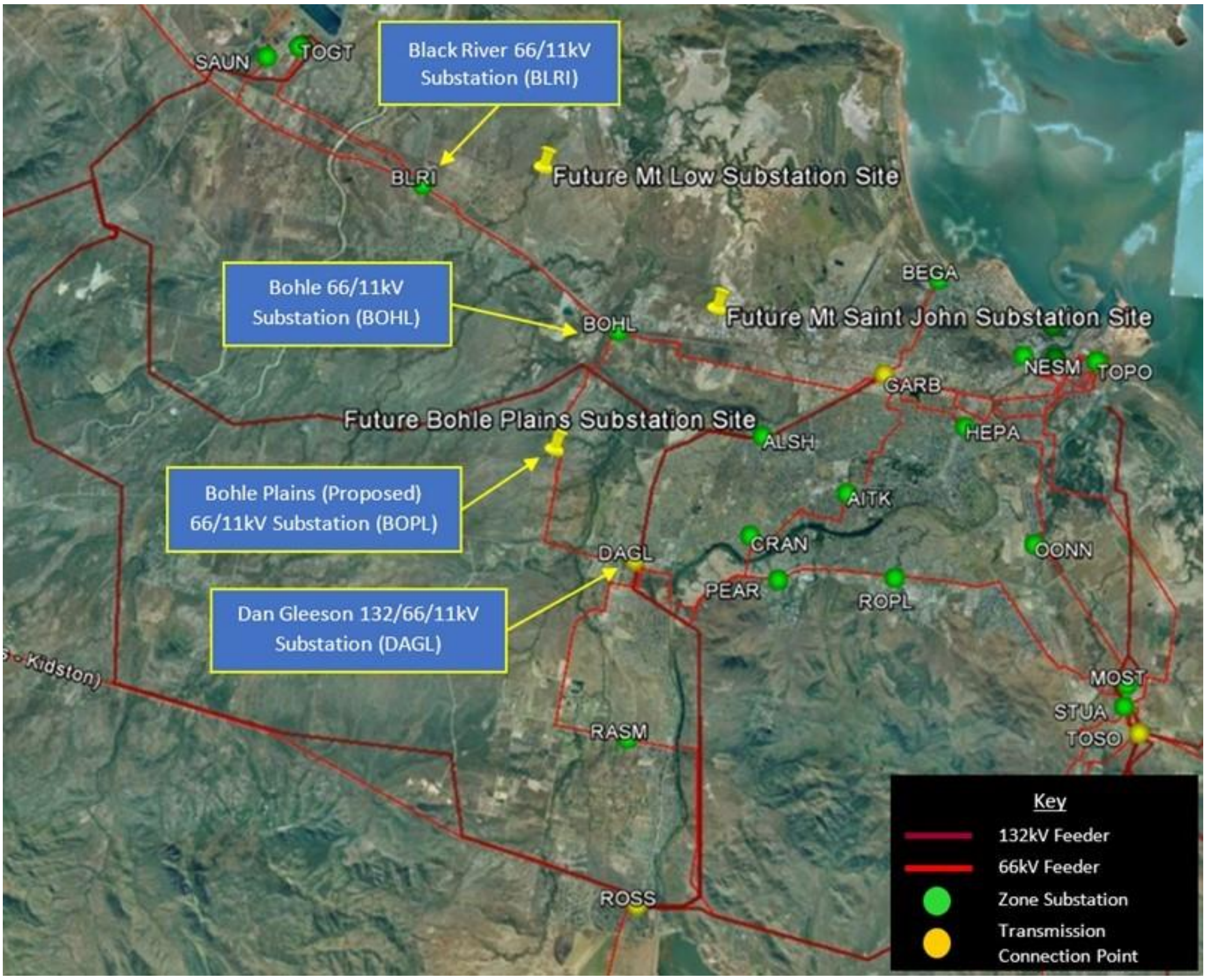


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. DAGL is supplied from T092 Dan Gleeson 132/66kV Bulk Supply Substation which is located on the same site. The other two main substations in the Townsville West area BOHL and Black River (BLRI) 66/11kV substation are normally supplied from two 66kV feeders, the DAGL-BOHL 66kV feeder from T092 Dan Gleeson 132/66kV Bulk Supply Substation and the GARB-BOHL 66kV feeder from T046 Garbutt Bulk Supply Substation.

BOHL is equipped with 2 x 25MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 5,112 predominantly residential customers. BOHL supplies 100 GWh of energy annually, with 35% of this energy consumed by residential customers.

DAGL is equipped with 2 x 25MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 8,127 predominantly residential customers. DAGL supplies 95 GWh of energy annually, with 66% of this energy consumed by residential customers.

BLRI is equipped with 2 x 20MVA 66/11kV transformers and has 10 x 11kV feeders which supply approximately 8,349 predominantly residential customers. BLRI supplies 87 GWh of energy annually, with 78% of this energy consumed by residential customers.

The DG-07, DG-10, BO-05 and BO-10 11kV feeders supply 4,181 predominantly residential customers and there has been significant growth in customer numbers and load due to the developments in the area.

Energy Queensland has installed two 4MW/8MWh Battery Energy Storage Systems (BESS) in this part of the Ergon Energy network as part of the Local Network Battery Plan[1]. The Black River 4MW/8MWh BESS is connected to BLRI and the Bohle 4MW/8MWh BESS is connected to BOHL.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of distribution network arrangement is illustrated in Figure 3.

[1] https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries

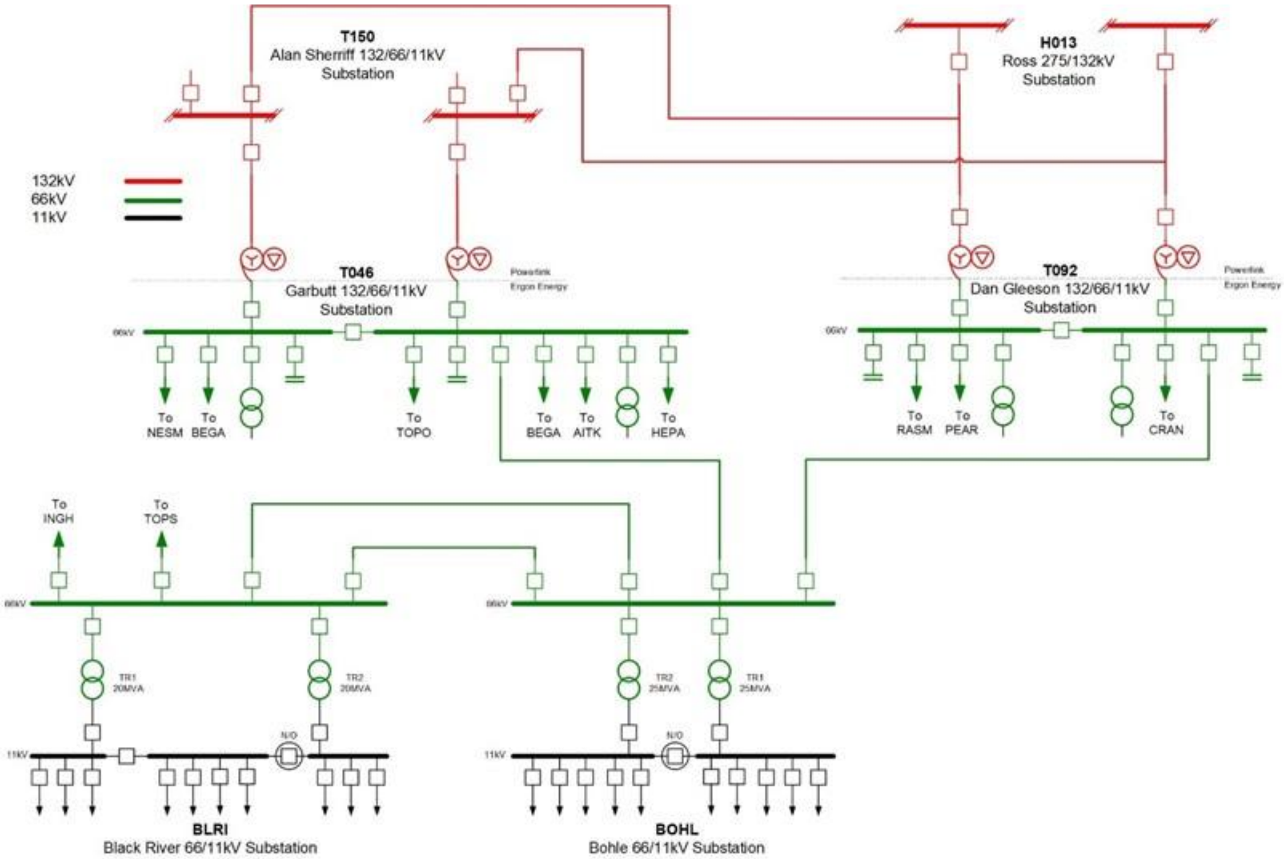


Figure 2: Existing network arrangement (schematic view)

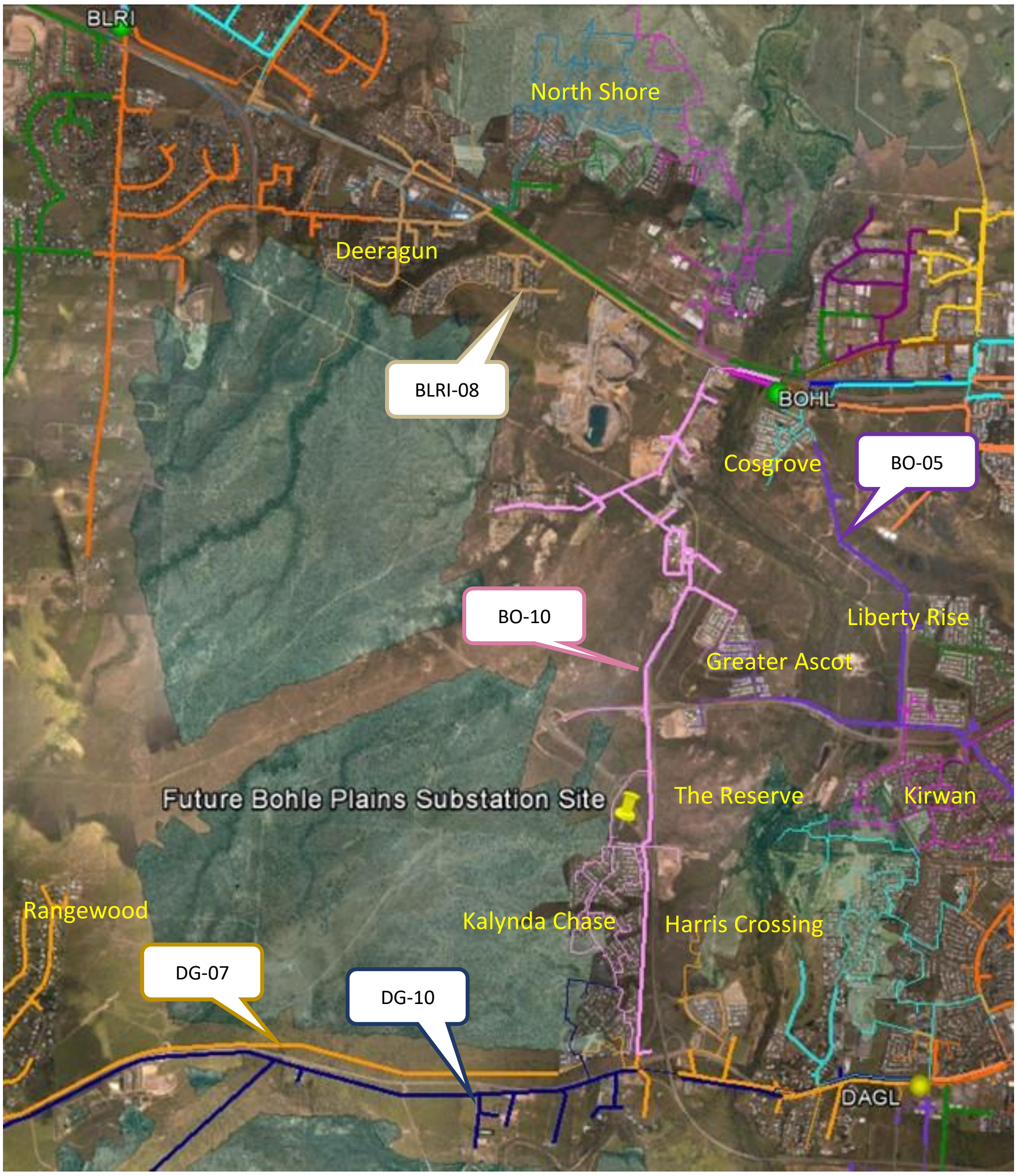


Figure 3: 11kV distribution feeders supplying Bohle Plains area (geographic view)

2.3. Load Profiles / Forecasts

The 11kV load at DAGL, BOHL and BLRI comprises a mix of residential and commercial/industrial customers. The load is Summer peaking, and the annual peak loads are predominantly driven by air conditioning loads during the Summer evening peak period. The annual minimum load generally occurs during the Winter and Spring midday period when export from rooftop solar PV systems can exceed the load in the area resulting in reverse flows from the distribution feeders into the zone substations.

2.3.1. Full Annual Load Profile

The full annual load profiles for DAGL, BOHL and BLRI over the 2022/23 and 2023/24 financial years is shown in Figure 4, Figure 5 and Figure 6. It can be noted that the peak load at these substations occurs during the Summer evening period and the minimum load at these substations occurs during the Winter and Spring midday periods.

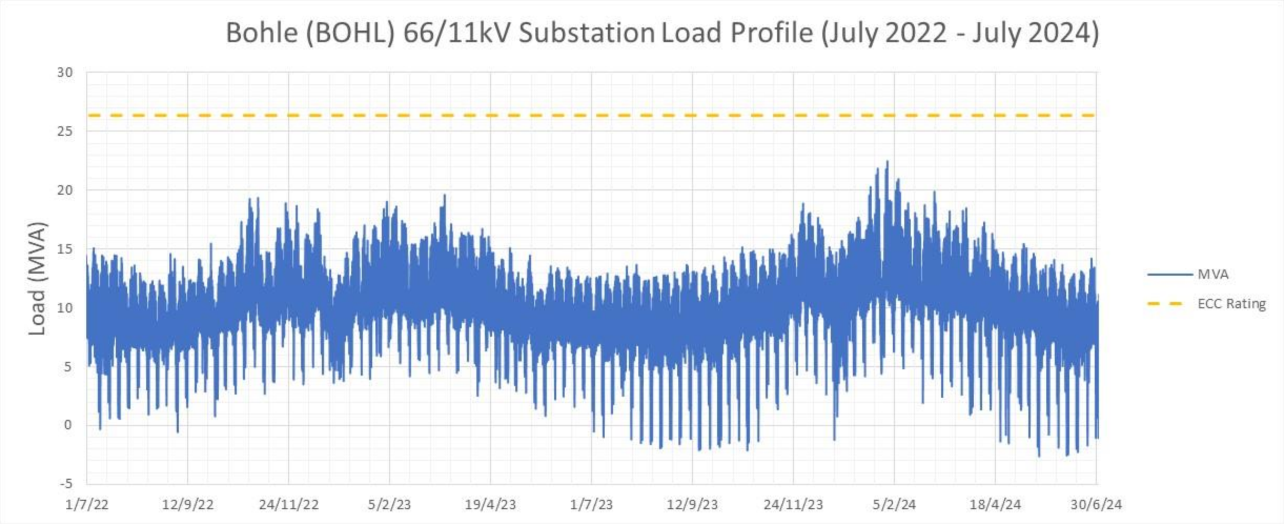


Figure 4: BOHL Substation 11kV load profile for period July 2022-July 2024

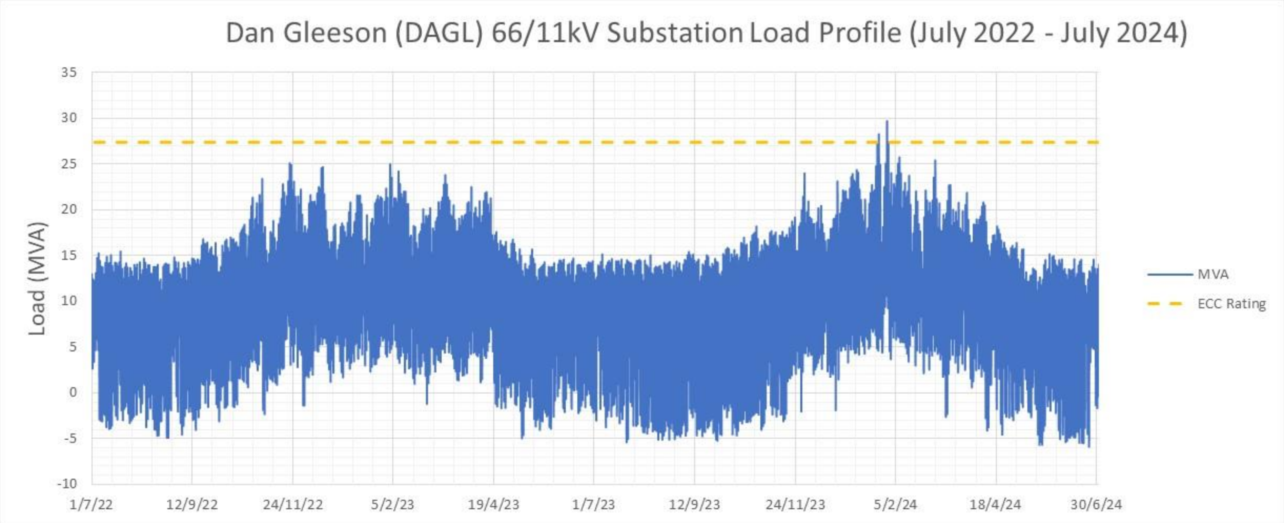


Figure 5: DAGL Substation 11kV load profile for period July 2022-July 2024

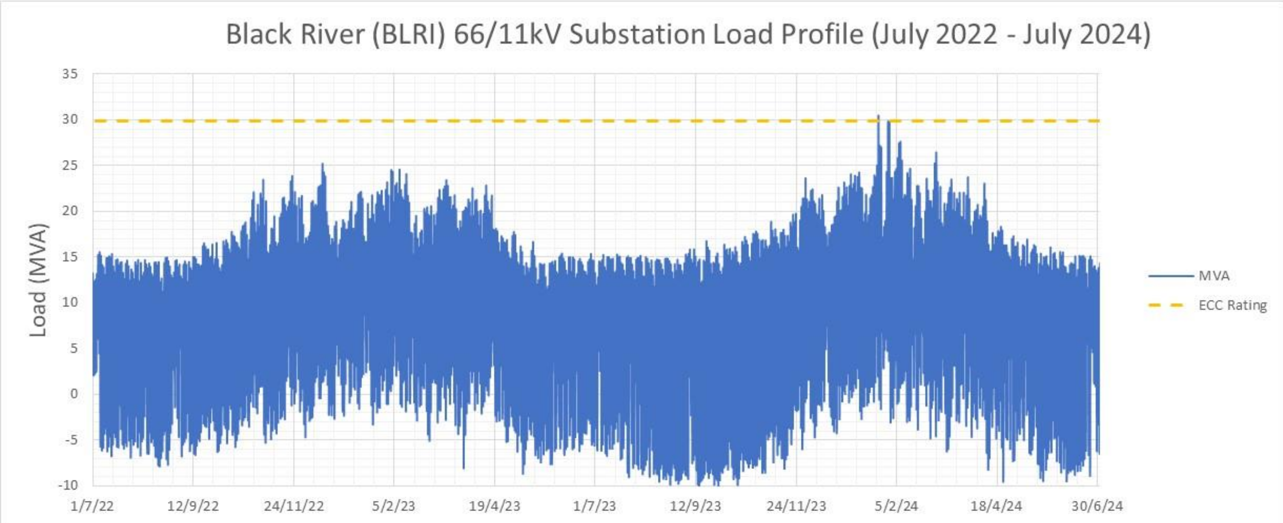


Figure 6: BLRI Substation 11kV load profile for period July 2022-July 2024

2.3.2. Load Duration Curve

The load duration curves for DAGL, BOHL and BLRI over the 2022/23 and 2023/24 financial years is shown in Figure 7, Figure 8 and Figure 9.

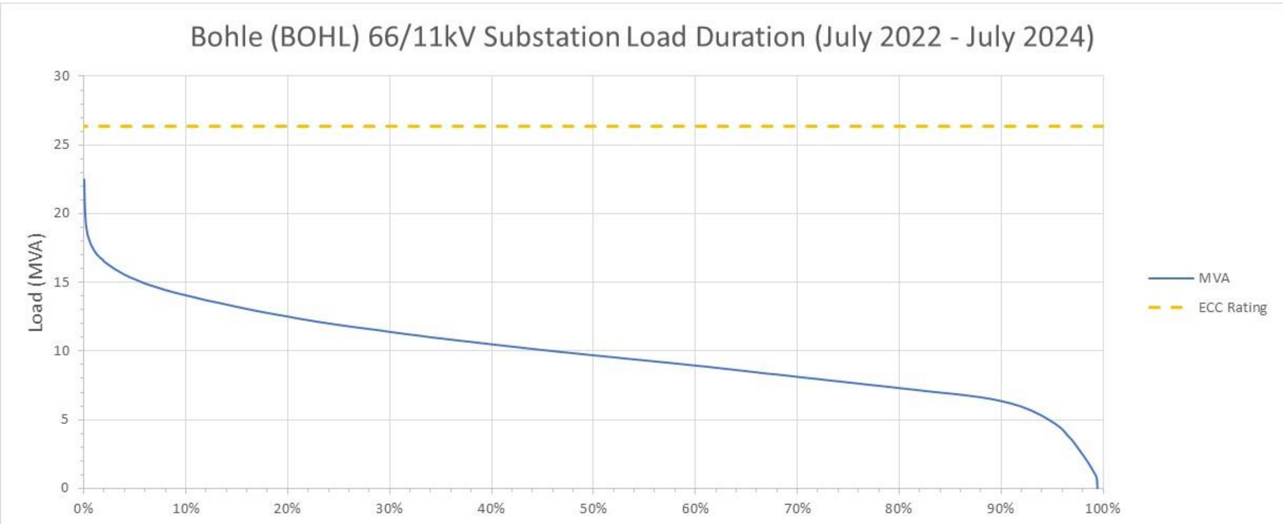


Figure 7: BOHL Substation 11kV load duration curve for period July 2022-July 2024

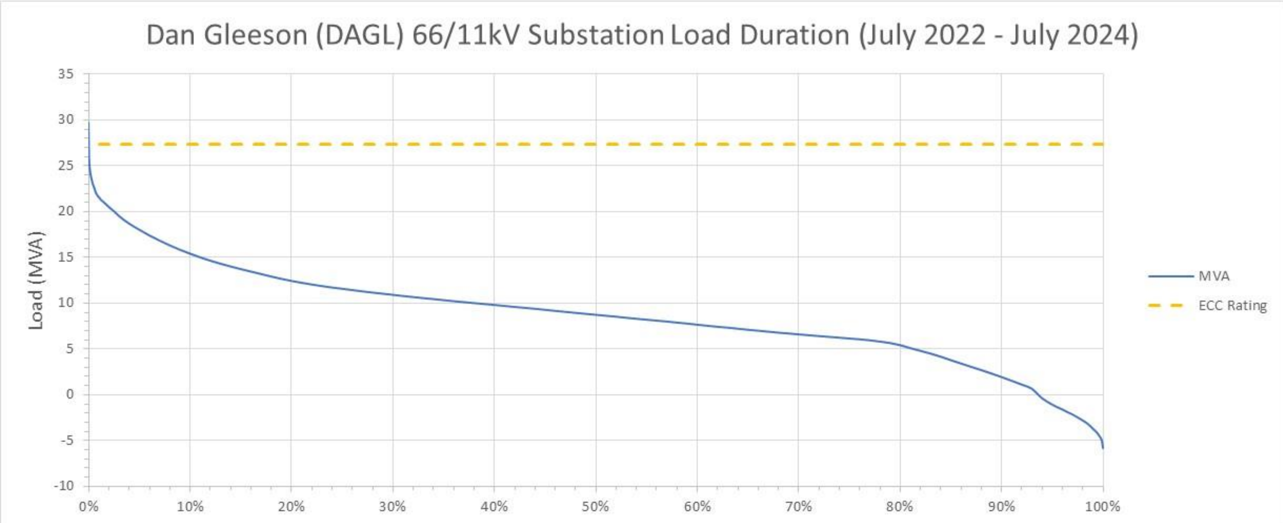


Figure 8: DAGL Substation 11kV load duration curve for period July 2022-July 2024

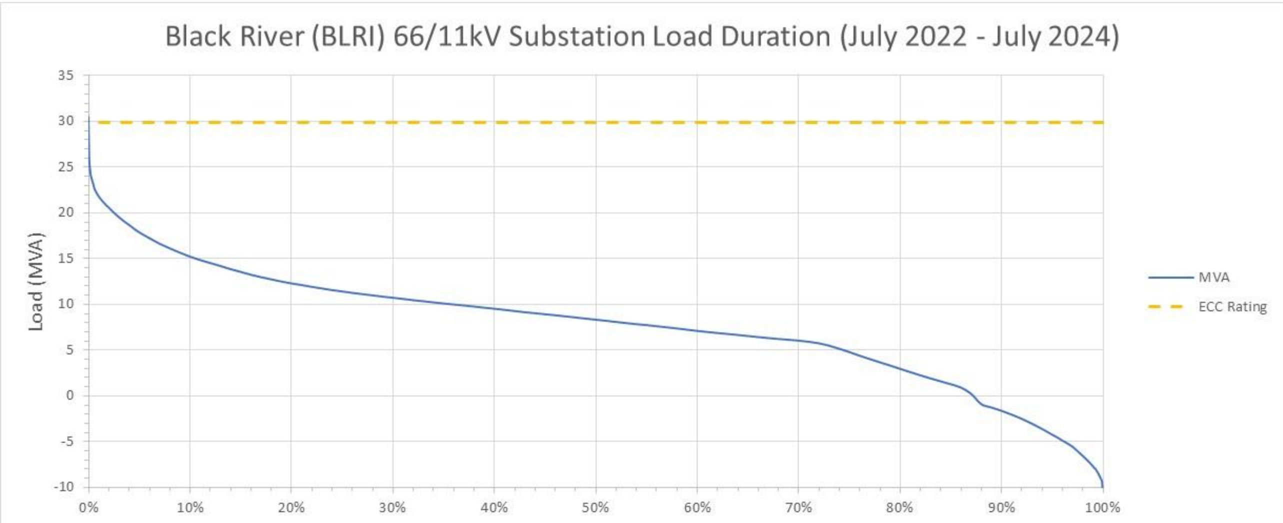


Figure 9: BLRI Substation 11kV load duration curve for period July 2022-July 2024

2.3.3. Average Peak Day Load Profile (Summer)

The daily load profile for the peak day and average of the top 5 peak days during the 2023/24 Summer period is illustrated below in Figure 10, Figure 11 and Figure 12. It can be noted that the Summer peak loads at DAGL, BOHL and BLRI are historically experienced in the late afternoon and evening.

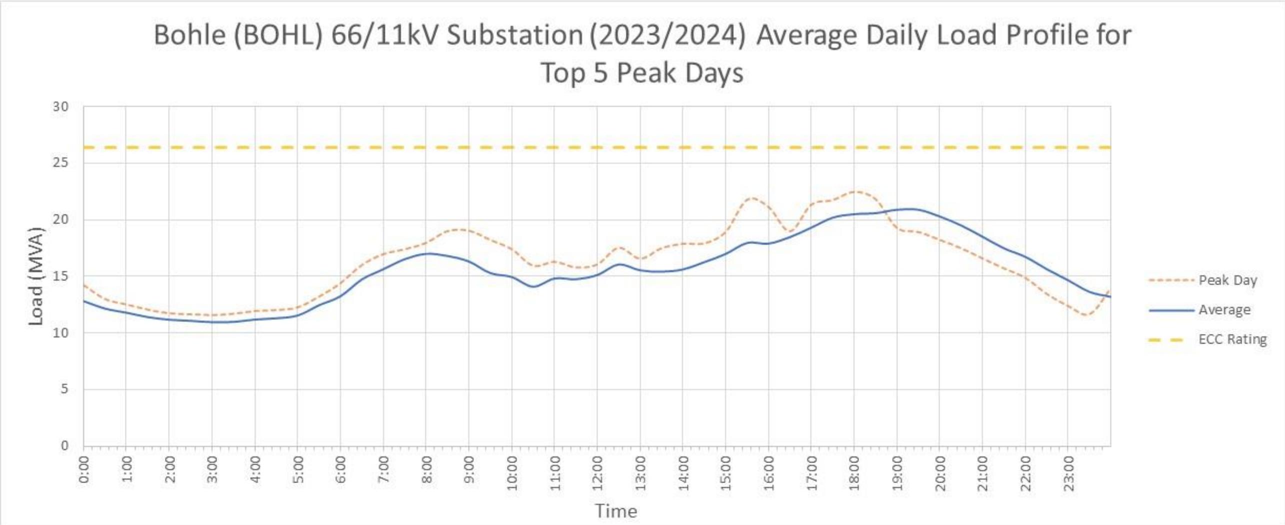


Figure 10: BOHL Substation average peak 11kV load profile (summer)

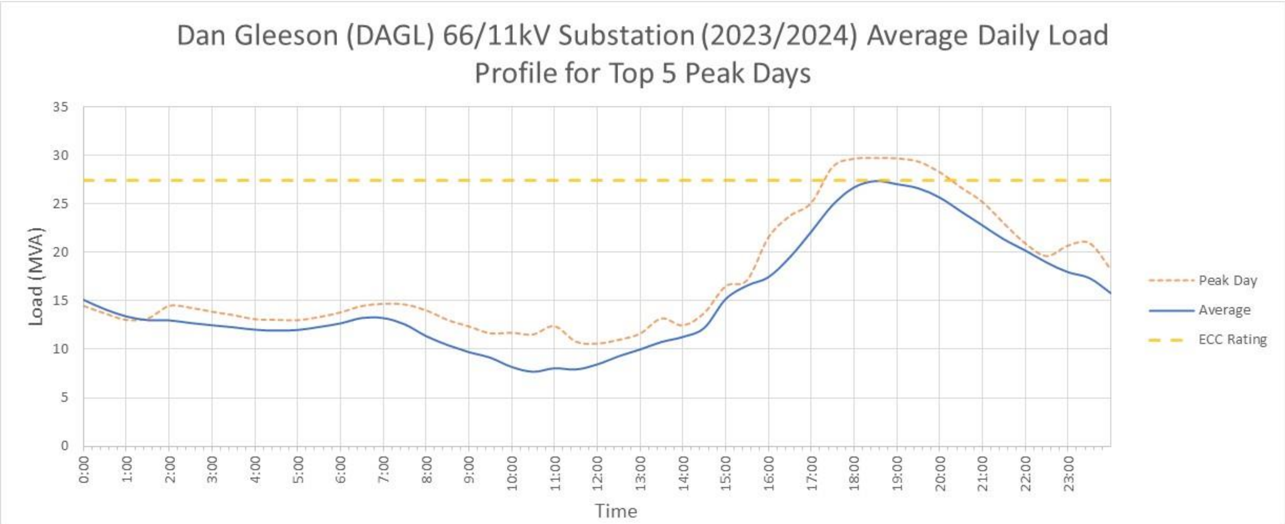


Figure 11: DAGL Substation average peak 11kV load profile (summer)

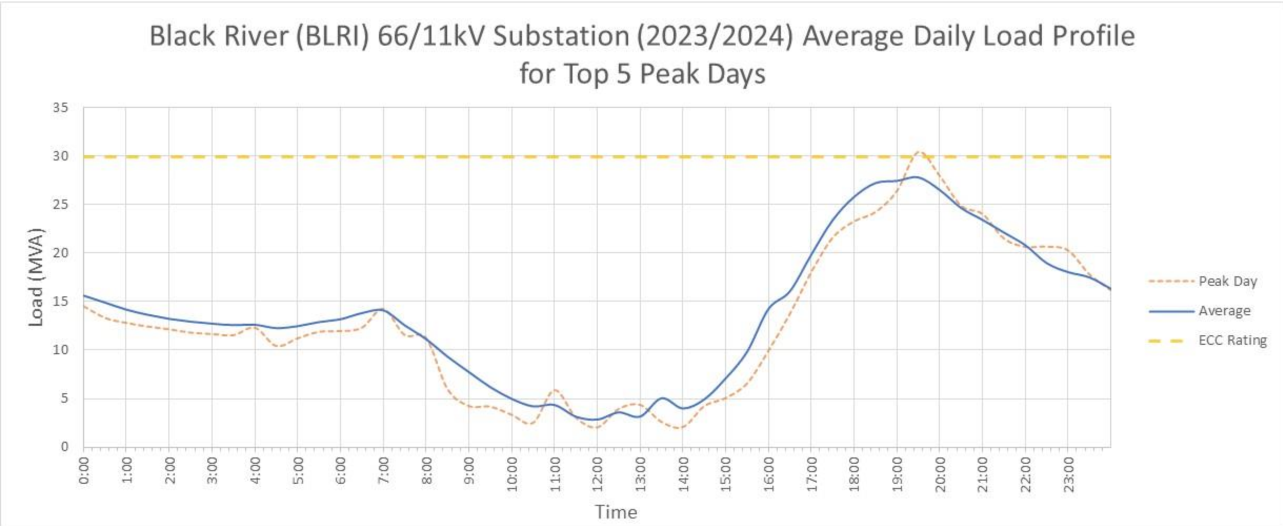


Figure 12: BLRI Substation average peak 11kV load profile (summer)

2.3.4. Average Load/Generation Profiles for 11kV feeders and Bohle BESS

The average daily load/generation profiles for the BO05, BO10, DG07 and DG10 11kV feeders and the Bohle BESS during the 2022/23 and 2023/24 Summer periods is illustrated below in Figure 13, Figure 14, Figure 15 and Figure 16. It can be noted that the Summer peak loads on the 11kV feeders are historically experienced in the late afternoon and evening. The Bohle BESS is connected to the BO10 feeder with import and export time of day limits based on the loading and capacity of the BO10 11kV feeder.

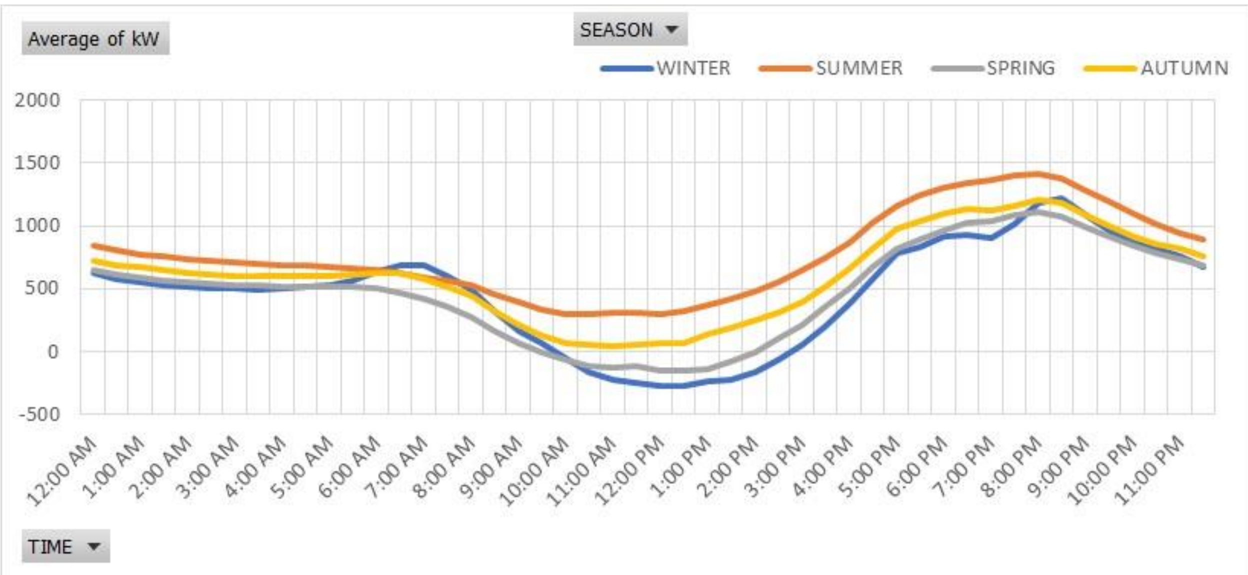


Figure 13: BO05 11kV feeder average load profile

Figure 14: BO10 11kV feeder average load profile (Bohle BESS is connected to this feeder)

The Bohle BESS influences the BO10 profile as it typically exports during the morning peak and evening peak periods.

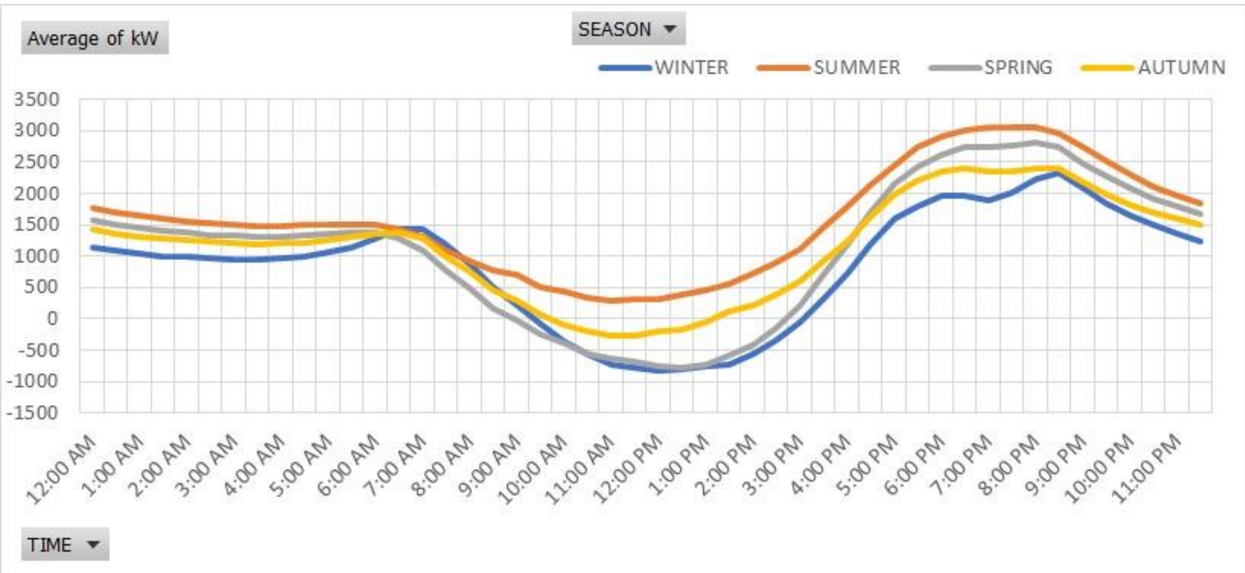


Figure 15: DG07 11kV feeder average load profile

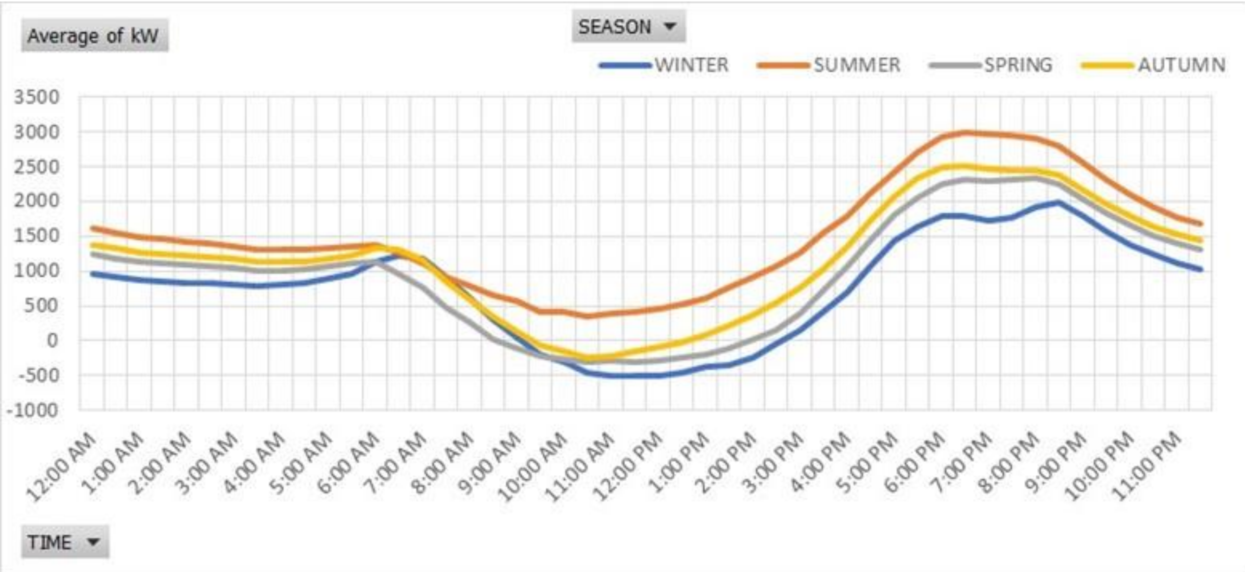


Figure 16: DG10 11kV feeder average load profile

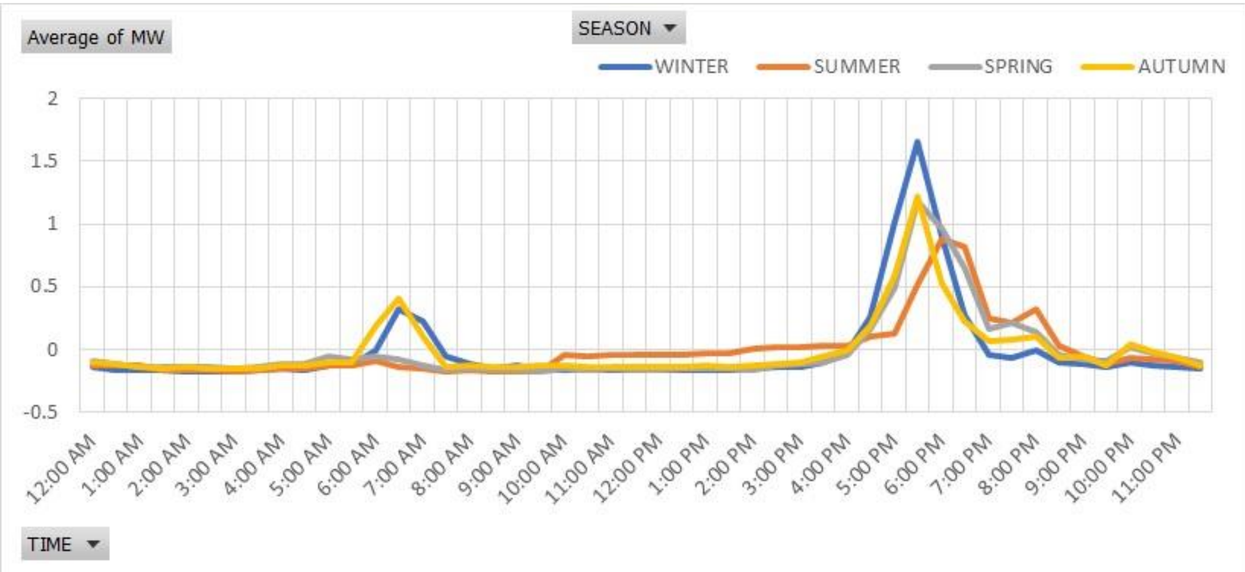


Figure 17: Bohle BESS average 11kV load/generation profile (positive = generation)

Note that the Bohle BESS import and export has time of day limits based on the loading and capacity of the BO10 11kV feeder.

2.3.5. Base Case Load Forecast

The 10 PoE (10% probability of exceedance) and 50 PoE (50% probability of exceedance) load forecasts for DAGL, BOHL and BLRI for the base case load growth scenario are illustrated in Figure 18, Figure 19 and Figure 20. The historical peak load for the past six years has also been included in the graphs.

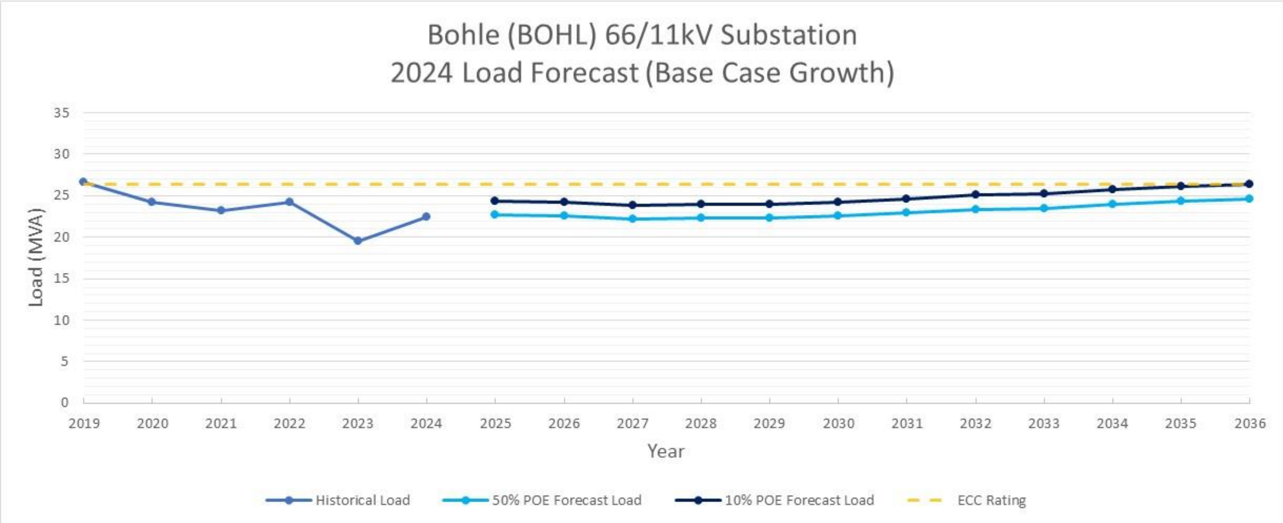


Figure 18: BOHL Substation base case 11kV load forecast

The historical annual peak loads at BOHL have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. In recent years the Bohle BESS has also influenced the peak loading on BOHL. The peak load is forecast to increase over the next 10 years under the base case scenario.

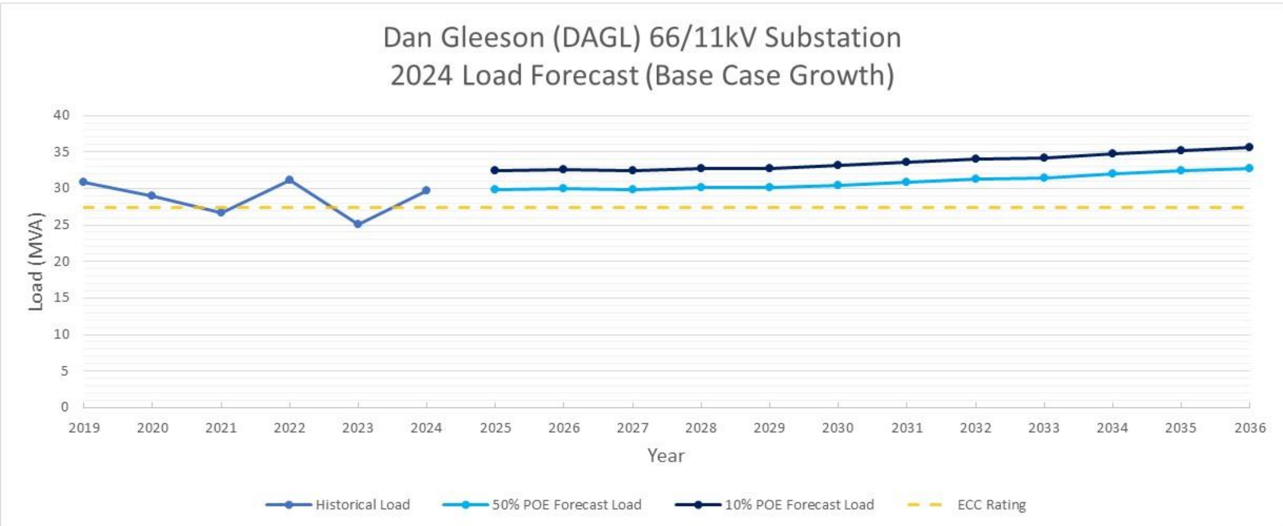


Figure 19: DAGL Substation base case 11kV load forecast

The historical annual peak loads at DAGL have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. The peak load is forecast to increase over the next 10 years under the base case scenario.

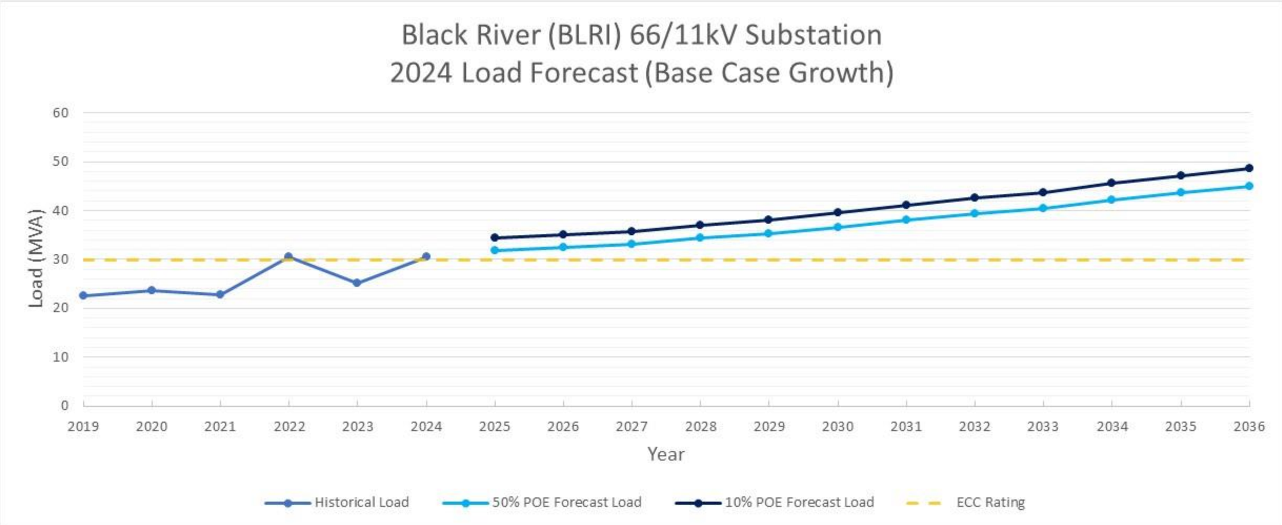


Figure 20: BLRI Substation base case 11kV load forecast

The historical annual peak loads at BLRI have fluctuated over the past six years due to changes in customer loads, fluctuations in ambient conditions and transfer of load to and from adjacent substations. The peak load is forecast to increase significantly over the next 10 years under the base case scenario.

2.3.6. High Growth Load Forecast

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

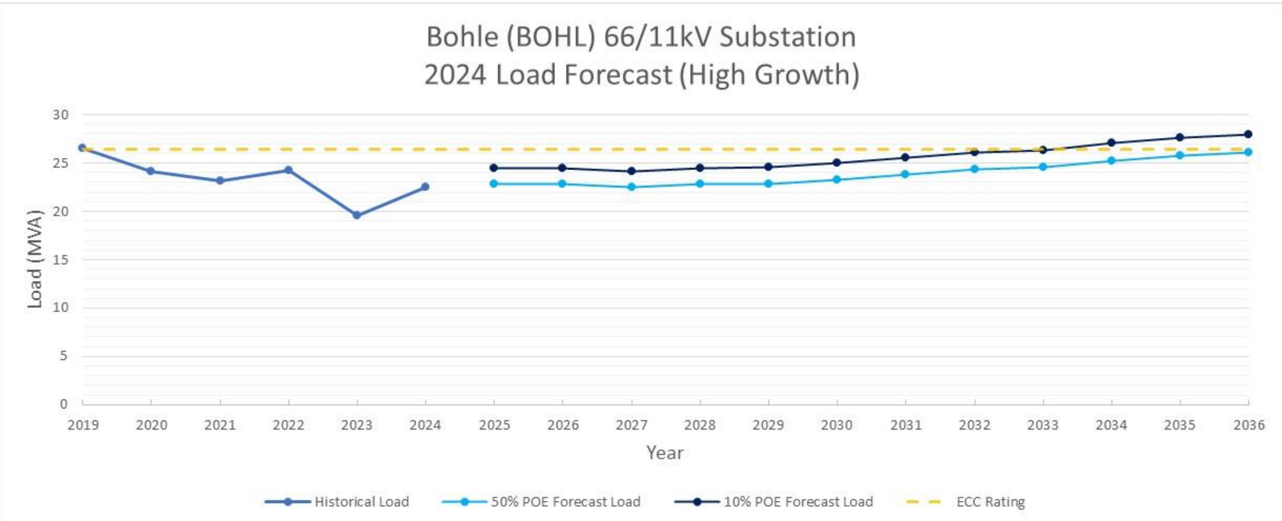


Figure 21: BOHL Substation high growth 11kV load forecast

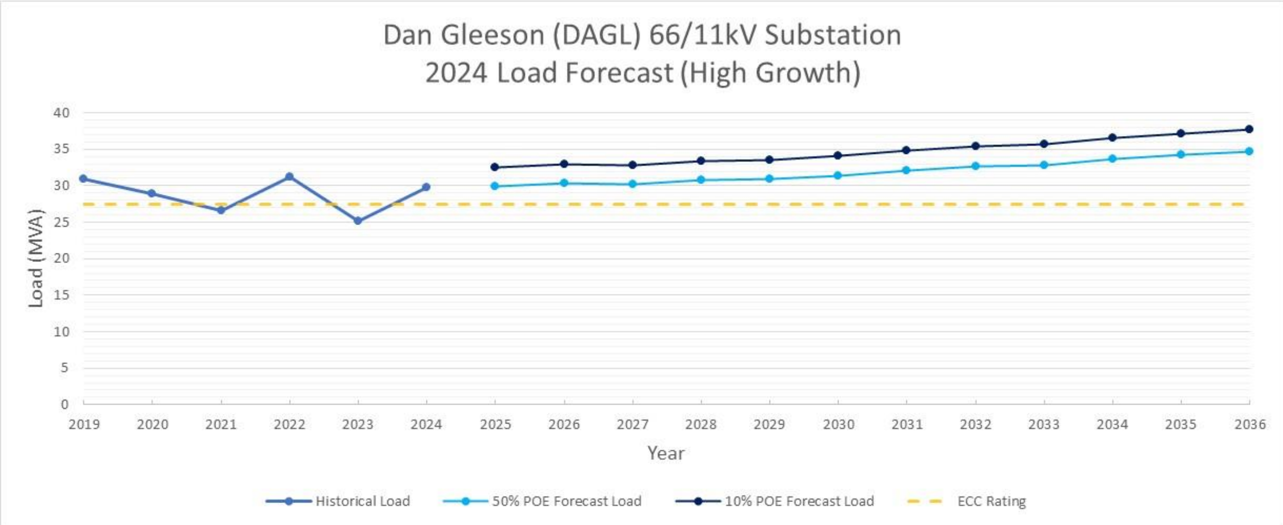


Figure 22: DAGL Substation high growth 11kV load forecast

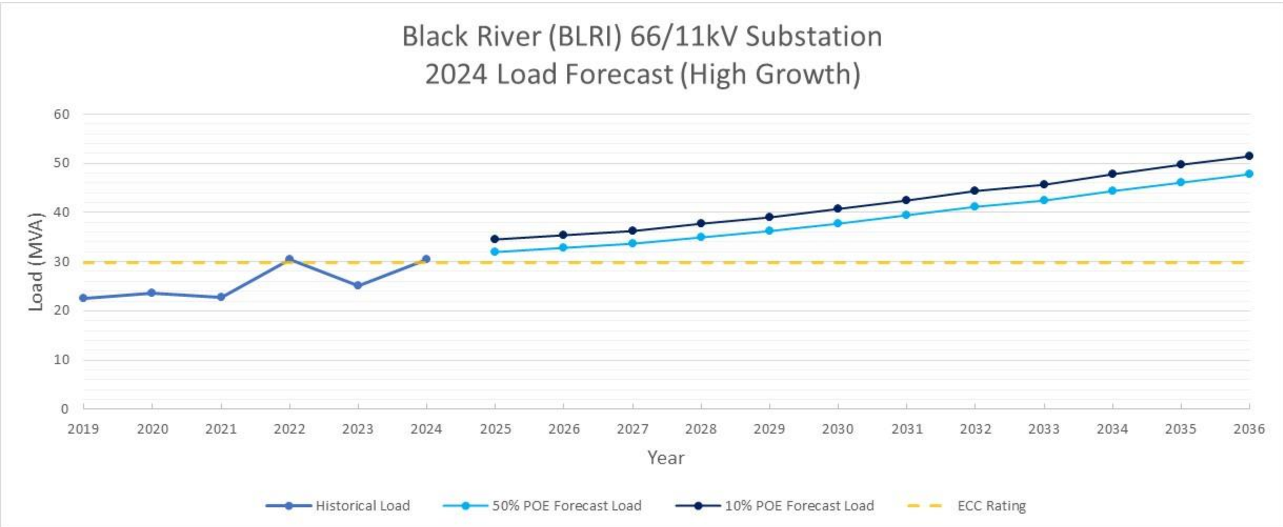


Figure 23: BLRI Substation high growth 11kV load forecast

2.3.7. Low Growth Load Forecast

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

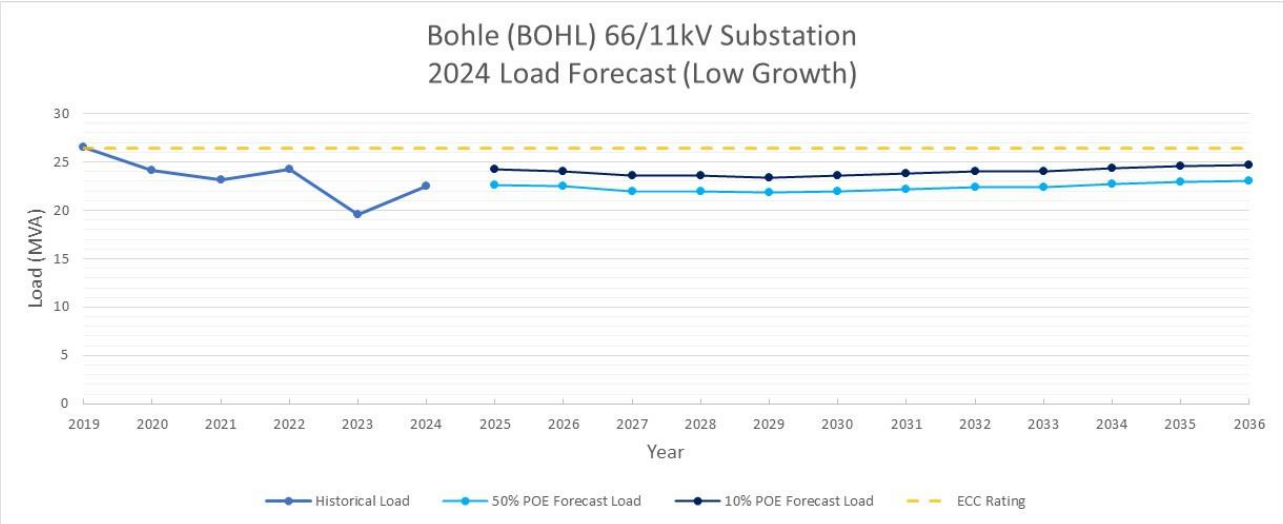


Figure 24: BOHL Substation low growth 11kV load forecast

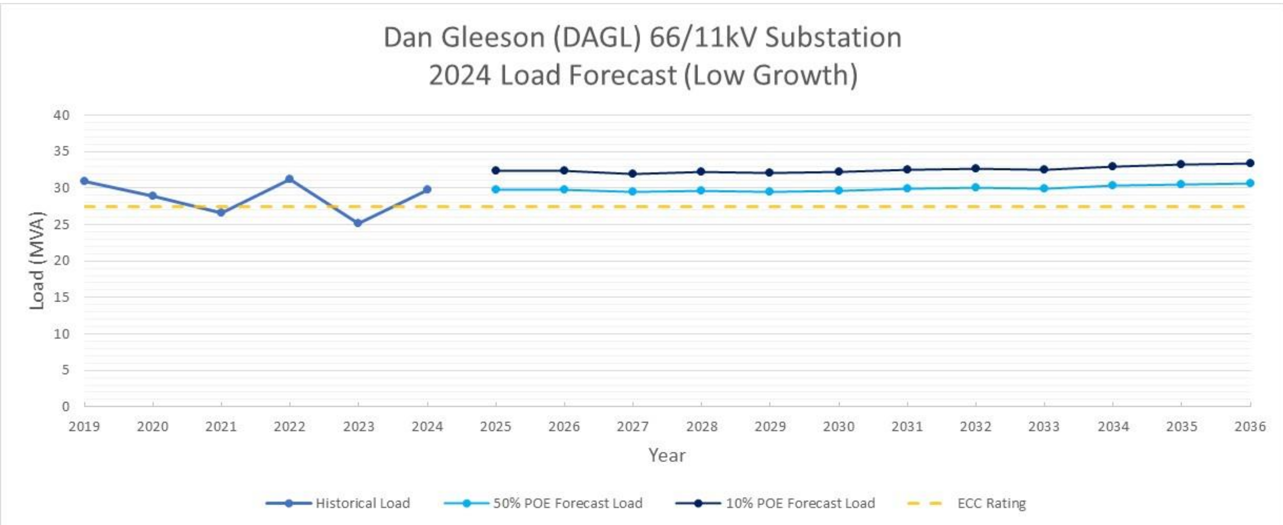


Figure 25: DAGL Substation low growth 11kV load forecast

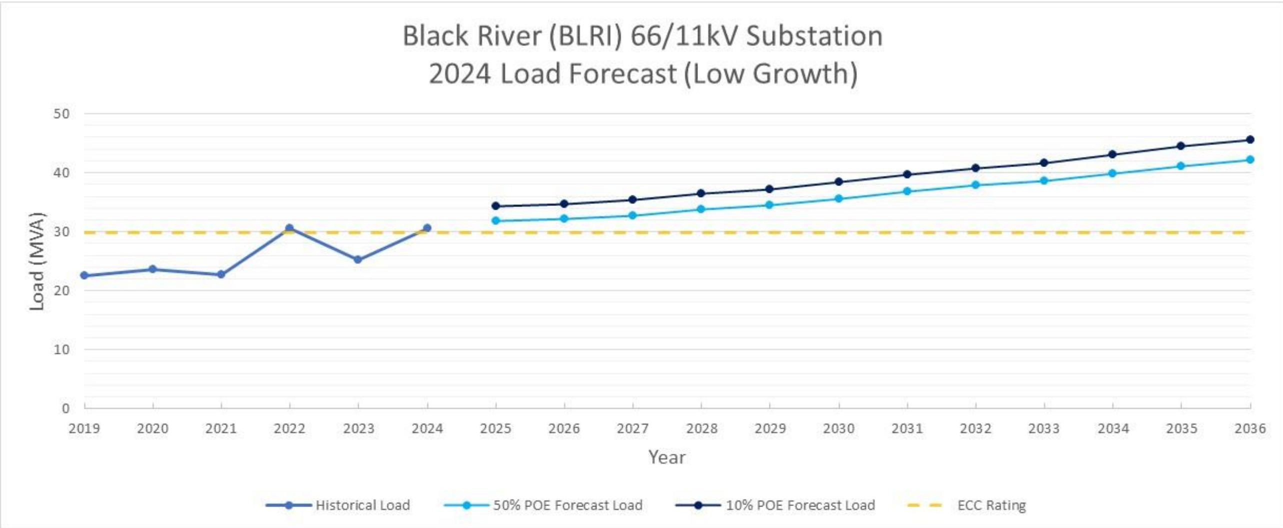


Figure 26: BLRI Substation low growth 11kV load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. The Bohle Plains area is one of the main residential development areas in the Townsville region with a number of new subdivisions under development.

Due to the forecasted increase in customer demand, Ergon Energy is seeking to invest in the network to undertake a reliability corrective action in order to continue to meet the service standards in its applicable regulatory instruments (Safety Net requirements). The forecast loading for the substations and distribution feeders supplying the Bohle Plains area is expected to exceed the available N-1 substation and feeder capacity within the next 10 years. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements. The typical repair times for a substation transformer fault or an underground cable fault would exceed the 24 hour period required to restore supply to all customers.

3.2. Assessment Criteria in relation to the Identified Need

3.2.1. Safety Net Criteria

Ergon Energy's Distribution Authority (issued under the *Electricity Act 1994* (Qld)), includes Safety Net targets. The Safety Net targets provide a 'base-case' or minimum security criteria for the network to be planned to, and provide protection against low probability, high impact events. The Distribution Authority requires Ergon Energy to ensure "to the extent reasonably practical" compliance with the Safety Net criteria.

The purpose of the Safety Net planning criteria is to avoid unexpected customer hardship and/or significant community or economic disruption by mitigating the effects of credible contingencies largely on the sub-transmission network, which have a low probability of occurring and result in high consequence network outages. Additional investment beyond the Safety Net requirements would be driven based on an economic, reliability based Value of Customer Reliability (VCR) methodology. This approach is consistent with the recommendations from the National Reliability Framework.

There are two sets of Safety Net targets applicable to Ergon Energy: "Regional Centre" and "Rural Areas", each having different timelines as shown below in Table 1.

BOHL, BLRI and DAGL are classified as Regional Centre substations.

Area	Targets (for restoration of supply following an N-1 Event)
Regional Centre	Following an N-1 event, load not supplied must be:

	○ Less than 20MVA (8000 customers) after 1 hour; ○ Less than 15MVA (6000 customers) after 6 hours; ○ Less than 5MVA (2000 customers) after 12 hours; and ○ Fully restored within 24 hours.
Rural Areas	Following an N-1 event, load not supplied must be: ○ Less than 20MVA (8000 customers) after 1 hour; ○ Less than 15MVA (6000 customers) after 8 hours; ○ Less than 5MVA (2000 customers) after 18 hours; and ○ Fully restored within 48 hours.
Note: All modelling and analysis will be benchmarked against 50% POE loads and based on credible contingencies. 'Regional Centre' relates to larger centres with predominantly urban feeders. 'Rural Areas' relates to areas that are not Regional Centres.	

Table 1: Ergon Energy service Safety Net targets

3.2.2. Reliability Standards

As per Ergon Energy's Distribution Authority, Ergon Energy is required to not exceed the minimum service standard (MSS) limits for the reliability performance of Ergon Energy's distribution network.

Minimum service standards (MSS) are assessed by feeder types as:

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

The legislated SAIDI and SAIFI limits from Ergon Energy's Distribution Authority are detailed in Table 2.

Feeder Category	SAIDI MSS Limits	SAIFI MSS Limits
Urban	149	1.98
Short Rural	424	3.95
Long Rural	964	7.40

Table 2: SAIDI (minutes per customer) and SAIFI (interruptions per customer) limits

The feeder performance categorisation is based on SAIDI indices against the MSS for a given financial year for each feeder category. The feeder status bands are as follows:

- Green Feeders have a SAIDI <= MSS (Minimum Service Standard) targets
- Yellow Feeders have a SAIDI > MSS < 150 % MSS
- Amber Feeders have a SAIDI > 150 % MSS < 200 % MSS
- Red Feeders have a SAIDI > 200 % MSS

3.2.3. Value of Customer Reliability

Value of Customer Reliability (VCR) is an economic value applied to customers' unserved energy for any particular year. VCR values represent customers' willingness across the National Electricity

Market (NEM) to pay for reliable electricity supply. The VCR is used for estimating market benefits that relate to reliability, such as changes in involuntary and voluntary load curtailment.

Any reduction in unserved energy a solution that addresses the identified need described in Section 3.1 will bring will be treated as a benefit based on the corresponding reduction in customer financial consequence.

The VCR calculated for this analysis for the customers supplied from BOHL, DAGL and BLRI is shown in Table 3 based on the VCR values for different customer types as published by the AER.

Substation	Sector	Annual Consumption (kWh)	$/kWh (2023)
BOHL	Residential (Climate Zone 1)	36,600,683	$28.07
	Commercial*	42,789,529	$52.20
	Industrial*	20,966,768	$74.78
	Agriculture*	-	$44.40
	Average VCR		**$48.12**
DAGL	Residential (Climate Zone 1)	66,134,682	$28.07
	Commercial*	29,703,442	$52.20
	Industrial*	1,649,117	$74.78
	Agriculture*	10,062	$44.40
	Average VCR		**$36.21**
BLRI	Residential (Climate Zone 1)	74,844,641	$28.07
	Commercial*	14,491,174	$52.20
	Industrial*	6,622,975	$74.78
	Agriculture*	23,484	$44.40
	Average VCR		**$34.94**

Table 3: AER VCR values for BOHL, DAGL and BLRI

*Business using <10MVA peak demand

$$VCR = \frac{(Residential\ kWh\ \times\ VCR) + (Commercial\ kWh\ \times\ VCR) + (Industrial\ kWh\ \times\ VCR) +\ (Agriculture\ kWh\ \times\ VCR)}{Total\ Energy}$$

3.3. Quantification of the Identified Need

3.3.1. Safety Net Non-Compliance

Bohle Substation Limitations

BOHL substation capacity is limited by the 66/11kV transformers, providing a Normal Cyclic Capacity (NCC) of 52.7 MVA and an Emergency Cyclic Capacity (ECC) of 26.4 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 4 and Table 5. In the event of a transformer failure at BOHL during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile generation if required. This assessment assumes that the Bohle 4MW / 8MWh BESS would be exporting during the peak period, if the BESS is not available at the time of the contingency the load at risk levels specified in Table 4 and Table 5 could potentially increase.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	22.4	0.0	-	-	-
2029	22.3	0.0	-	-	-
2030	22.6	0.0	-	-	-
2031	23.0	0.0	-	-	-
2032	23.4	0.0	-	-	-
2033	23.5	0.0	-	-	-
2034	24.0	0.0	-	-	-
2035	24.4	0.0	-	-	-
2036	24.6	0.0	-	-	-
2037	24.9	0.0	-	-	-
2038	25.2	0.0	-	-	-
2039	25.5	0.0	-	-	-

Table 4: BOHL Base Case Growth 50PoE Forecast Load at Risk

Table 4 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a base case growth scenario.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	22.8	0.0	-	-	-
2029	22.9	0.0	-	-	-
2030	23.3	0.0	-	-	-
2031	23.8	0.0	-	-	-
2032	24.4	0.0	-	-	-
2033	24.6	0.0	-	-	-
2034	25.3	0.0	-	-	-
2035	25.7	0.0	-	-	-
2036	26.1	0.0	-	-	-

2037	26.5	0.0	-	-	-
2038	26.9	0.0	-	-	-
2039	27.4	0.0	-	-	-

Table 5: BOHL High Growth Case 50PoE Forecast Load at Risk

Table 5 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a high growth scenario.

Dan Gleeson Substation Limitations

DAGL substation capacity is limited by the 11kV transformer cables, providing a Normal Cyclic Capacity (NCC) of 42.4 MVA and an Emergency Cyclic Capacity (ECC) of 27.2 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 6 and Table 7. In the event of a transformer failure at DAGL during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile generation if required.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	30.1	0.0	-	-	-
2029	30.2	0.0	-	-	-
2030	30.5	0.0	-	-	-
2031	30.9	0.0	-	-	-
2032	31.3	0.1	1	0.01%	0.5
2033	31.4	0.2	1	0.01%	0.5
2034	32.0	0.8	1	0.01%	1
2035	32.4	1.2	2	0.02%	2
2036	32.8	1.6	2	0.03%	3
2037	33.2	2.0	3	0.05%	4
2038	33.6	2.4	4	0.07%	6
2039	33.9	2.7	5	0.10%	8.5

Table 6: DAGL Base Case Growth 50PoE Forecast Load at Risk

Table 6 illustrates the amount and duration of support required at DAGL under a base case growth scenario, starting at 0.1MVA for 1 day in 2032 increasing to 2.4MVA for 4 days in 2038.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	30.7	0.0	-	-	-
2029	30.9	0.0	-	-	-
2030	31.4	0.2	1	0.01%	0.5
2031	32.0	0.8	1	0.01%	1
2032	32.6	1.4	2	0.03%	2.5
2033	32.8	1.6	2	0.03%	3
2034	33.6	2.4	4	0.07%	6.5

2035	34.2	3.0	6	0.11%	9.5
2036	34.7	3.5	7	0.15%	13
2037	35.3	4.1	9	0.19%	16.5
2038	35.8	4.6	13	0.26%	23
2039	36.4	5.2	15	0.35%	30.5

Table 7: DAGL High Growth Case 50PoE Forecast Load at Risk

Table 7 illustrates the amount and duration of support required at DAGL under a high growth scenario, starting at 0.2MVA for 1 day in 2030 increasing to 4.6MVA for 13 days in 2038.

Black River Substation Limitations

BLRI substation capacity is limited by the 66/11kV transformers, providing a Normal Cyclic Capacity (NCC) of 56 MVA and an Emergency Cyclic Capacity (ECC) of 29.9 MVA. The 50PoE load forecast and Safety Net load at risk for a contingency is shown in Table 8 and Table 9. In the event of a transformer failure at BLRI during a peak load period, up to 4 MVA of load can be transferred to adjacent substations via the 11kV feeder ties and supplemented by mobile generation if required. This assessment also assumes that the Black River 4MW / 8MWh BESS would be exporting during the peak period so if this is not available at the time of the contingency the load at risk levels specified in Table 8 and Table 9 could potentially increase.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	34.3	0.4	1	0.01%	0.5
2029	35.3	1.4	5	0.06%	5
2030	36.6	2.7	10	0.15%	13.5
2031	38.0	4.1	18	0.36%	31.5
2032	39.4	5.5	26	0.61%	53.5
2033	40.5	6.6	33	0.90%	78.5
2034	42.2	8.3	45	1.38%	120.5
2035	43.6	9.7	56	1.83%	160.5
2036	45.1	11.2	68	2.36%	206.5
2037	46.5	12.6	85	2.93%	256.5
2038	47.9	14.0	100	3.53%	309.5
2039	49.3	15.4	113	4.18%	366

Table 8: BLRI Base Case Growth 50PoE Forecast Load at Risk

Table 8 illustrates the amount and duration of support required at BLRI under a base case growth scenario, starting at 0.4MVA for 1 day in 2028 increasing to 14MVA for 100 days in 2038.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	35.0	1.1	3	0.04%	3.5
2029	36.2	2.3	7	0.11%	9.5
2030	37.7	3.8	16	0.29%	25.5

2031	39.4	5.5	26	0.61%	53.5
2032	41.1	7.2	38	1.06%	93
2033	42.4	8.5	47	1.44%	126
2034	44.4	10.5	61	2.09%	183
2035	46.1	12.2	79	2.77%	242.5
2036	47.8	13.9	100	3.47%	304
2037	49.4	15.5	114	4.22%	370
2038	51.1	17.2	133	5.08%	445
2039	52.8	18.9	150	6.03%	528.5

Table 9: BLRI High Growth Case 50PoE Forecast Load at Risk

Table 9 illustrates the amount and duration of support required at BLRI under a high growth scenario, starting at 1.1MVA for 3 days in 2028 increasing to 17.2MVA for 133 days in 2038.

11kV Feeder Limitations

The Bohle Plains area is currently supplied from the DG-07, DG-10, BO-05 and BO-10 11kV distribution feeders from Dan Gleeson (DAGL) 66/11kV Substation and Bohle (BOHL) 66/11kV Substation. There are existing projects planned to increase the capacity of the DG07 and DG10 feeders to address supply limitations, however due to the growth in the Bohle Plains area these feeders are forecast to become constrained again within the next 10 years. The 50PoE load forecast and Safety Net load at risk for a contingency on one of these feeders is shown in Table 10 and Table 11. After the upgrade works on these feeders have been completed, in the event of a cable failure on either the DG07 or DG10 11kV feeder during a peak load period, up to 10.43 MVA of the combined DG07 & DG10 feeder load can be supplied via transfers to adjacent 11kV feeders and supplemented by 1MVA of mobile generation if required.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	11.6	0.19	1	0.01%	1
2029	11.7	0.31	1	0.01%	1
2030	11.9	0.45	1	0.01%	1
2031	12.0	0.60	2	0.02%	1.5
2032	12.1	0.69	2	0.02%	2
2033	12.2	0.79	2	0.02%	2
2034	12.3	0.90	3	0.03%	3
2035	12.5	1.02	3	0.04%	3.5
2036	12.6	1.15	4	0.06%	5
2037	12.7	1.29	5	0.09%	8
2038	12.9	1.43	7	0.13%	11
2039	12.9	1.51	7	0.14%	12

Table 10: DG07 & DG10 Feeders Base Case Growth 50PoE Forecast Load at Risk

Table 10 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a base case growth scenario, starting at 0.19MVA for 1 day in 2028 increasing to 1.43MVA for 7 days in 2038.

Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
2028	11.7	0.22	1	0.01%	1
2029	11.8	0.36	1	0.01%	1
2030	11.9	0.51	2	0.02%	1.5
2031	12.1	0.67	2	0.02%	2
2032	12.2	0.76	2	0.02%	2
2033	12.3	0.86	2	0.03%	2.5
2034	12.4	0.97	3	0.03%	3
2035	12.5	1.08	3	0.05%	4
2036	12.6	1.19	4	0.06%	5.5
2037	12.8	1.32	5	0.10%	8.5
2038	12.9	1.44	7	0.13%	11.5
2039	13.0	1.58	7	0.14%	12

Table 11: DG07 & DG10 Feeders High Growth Case 50PoE Forecast Load at Risk

Table 11 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a high growth scenario, starting at 0.22MVA for 1 day in 2028 increasing to 1.44MVA for 7 days in 2038.

3.4. Assumptions in Relation to Identified Need

Below is a summary of key assumptions used in identifying the identified need.

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.

On the basis of these assumptions, Ergon Energy has come to the conclusion that a reliability corrective action is necessary. Without taking a reliability corrective action, Ergon Energy considers that it would be in breach of its Safety Net requirements. In the event of a fault on a substation transformer or an underground substation exit cable for one of the feeders supplying the Bohle Plains area there is a risk that a portion of the forecast load would be unsupplied for more than 24 hours, thereby breaching Safety Net requirements.

3.4.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at BOHL, DAGL and BLRI substations will be consistent with the base case forecast outlined in Section 2.3.5.

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, etc.);

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

3.4.2. 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.

3.4.3. Network Batteries

As part of the Local Network Battery Plan, Energy Queensland has installed two 4MW/8MWh batteries in this area to capture extra energy generated from rooftop PV systems and then export this energy back into the network during the peak demand period. Energy Queensland, as part of the Queensland Energy and Jobs Plan, is planning to install more batteries across the network to maximise the benefits of rooftop solar and provide network support. The Bohle Plains area also falls within the recently announced Townsville Local Renewable Energy Zone (LREZ) which proposes the installation of local network-connected batteries.

If they provide support during the peak demand period in the required locations, the installation of additional batteries within the Bohle Plains area is anticipated to assist in reducing the peak demand and may change the timing and/or scope of any proposed solutions. However, at this stage as details on the location and size of these batteries has not been confirmed it has been assumed that these batteries would not fully address the identified need.

4. POTENTIAL CREDIBLE OPTIONS

The following is a summary of potential credible options to address the identified need, including network options, non-network options and SAPS options.

4.1. Non-Network Options or SAPS Options Identified

As per Section 6.1, Ergon Energy has not identified any credible non-network solutions or SAPS options that would provide a complete or a hybrid (combined network and non-network) solution to address the identified need. Ergon Energy is publishing this Options Screening Report seeking information from all interested parties about potential credible non-network or SAPS options that could address the identified need.

Ergon Energy currently has a request for proposal (RFP)[2] on the Ergon Energy website seeking demand response or non-network solutions to address various 11kV feeder limitations. This RFP includes 11kV feeders from BLRI, DAGL and BOHL substations. At the time of publishing this Options Screening Report, Ergon Energy had received no submissions in relation to this RFP.

4.2. Network Options Identified

Ergon Energy has identified three potential credible network options that would address the identified need.

4.2.1. Option A: Establish Bohle Plains Zone Substation with a single 66/11kV transformer

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements. It would involve establishing a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network to address the identified need. A second transformer would be installed as part of a future project when the loading on the proposed new substation exceeds the available backup capacity.

The estimated capital cost of this option is $14.7 million, which has been factored into the NPV to be incurred in 2029. The installation of a future second transformer with an estimated capital cost of $2.8 million has been factored into NPV calculations to be incurred in 2038.

[2] https://www.ergon.com.au/__data/assets/pdf_file/0010/1079029/Ergon-Network-Request-for-Proposal-Distribution-Feeder-Limitations-2024-2025.pdf

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 27.

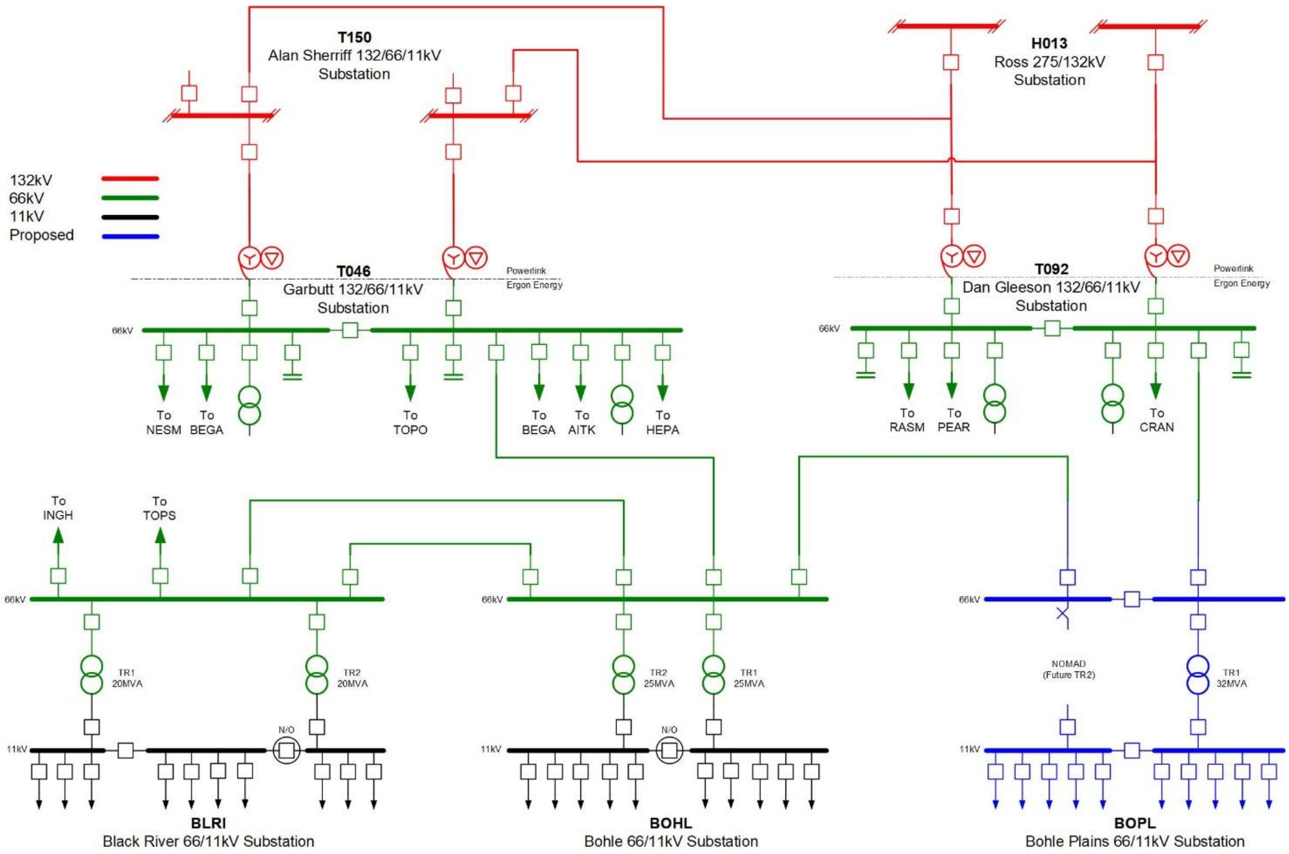


Figure 27: Option A proposed network arrangement (schematic view)

4.2.2. Option B: Establish Bohle Plains Zone Substation with two 66/11kV transformers

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements. It would involve establishing a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 2 x 66kV transformer bays, 2 x 32MVA 66/11kV transformers, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network to address the identified need.

The estimated capital cost of this option is $17.2 million, which has been factored into the NPV to be incurred in 2029.

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

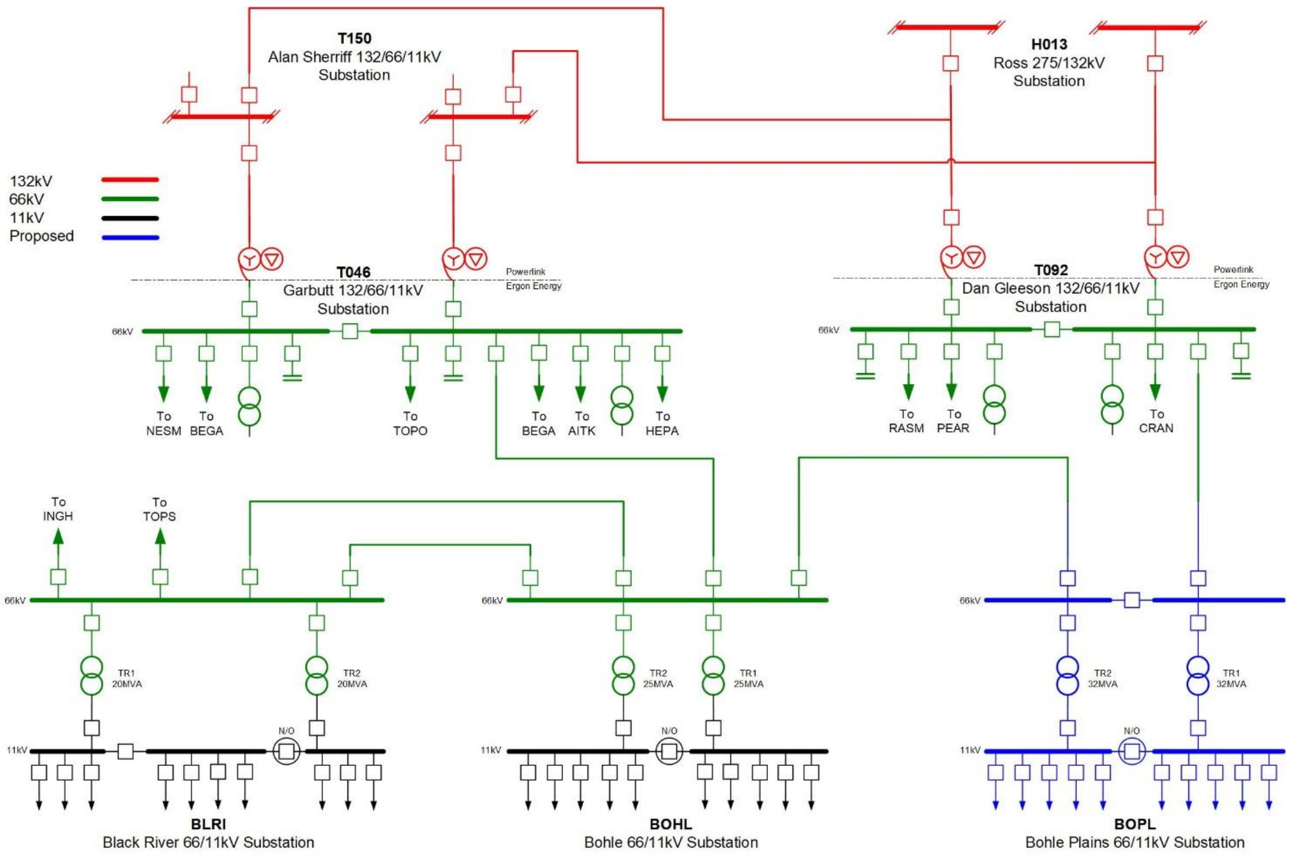


Figure 28: Option B proposed network arrangement (schematic view)

4.2.3. Option C: Upgrade Dan Gleeson, Bohle and Black River Substations and install additional 11kV feeders into the area to defer the establishment of Bohle Plains Substation

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2029 and would address the identified need by providing additional network capacity to supply the forecast load in the Bohle Plains area. This would ensure Ergon Energy is complaint with applicable regulatory instruments, including its Safety Net requirements. It would involve upgrading BLRI with 2 x 32MVA 66/11kV transformers, upgrading BOHL with 2 x 32MVA transformers, upgrading BOHL 11kV transformer cables, upgrading DAGL 11kV transformer cables, installing new 11kV feeder bays at BOHL & DAGL, establishing a new 11kV feeder from DAGL and a new 11kV feeder from BOHL to supply the Bohle Plains area to address the identified need. This option defers the need for the proposed new Bohle Plains substation by around 10 years.

The estimated capital cost of this option is $11.8 million, which has been factored into the NPV to be incurred in 2029. The establishment of the future Bohle Plains Substation with an estimated capital cost of $17.2 million has been factored into NPV calculations to be incurred in 2038.

A schematic diagram with the proposed network arrangement for Option C is shown in Figure 29.

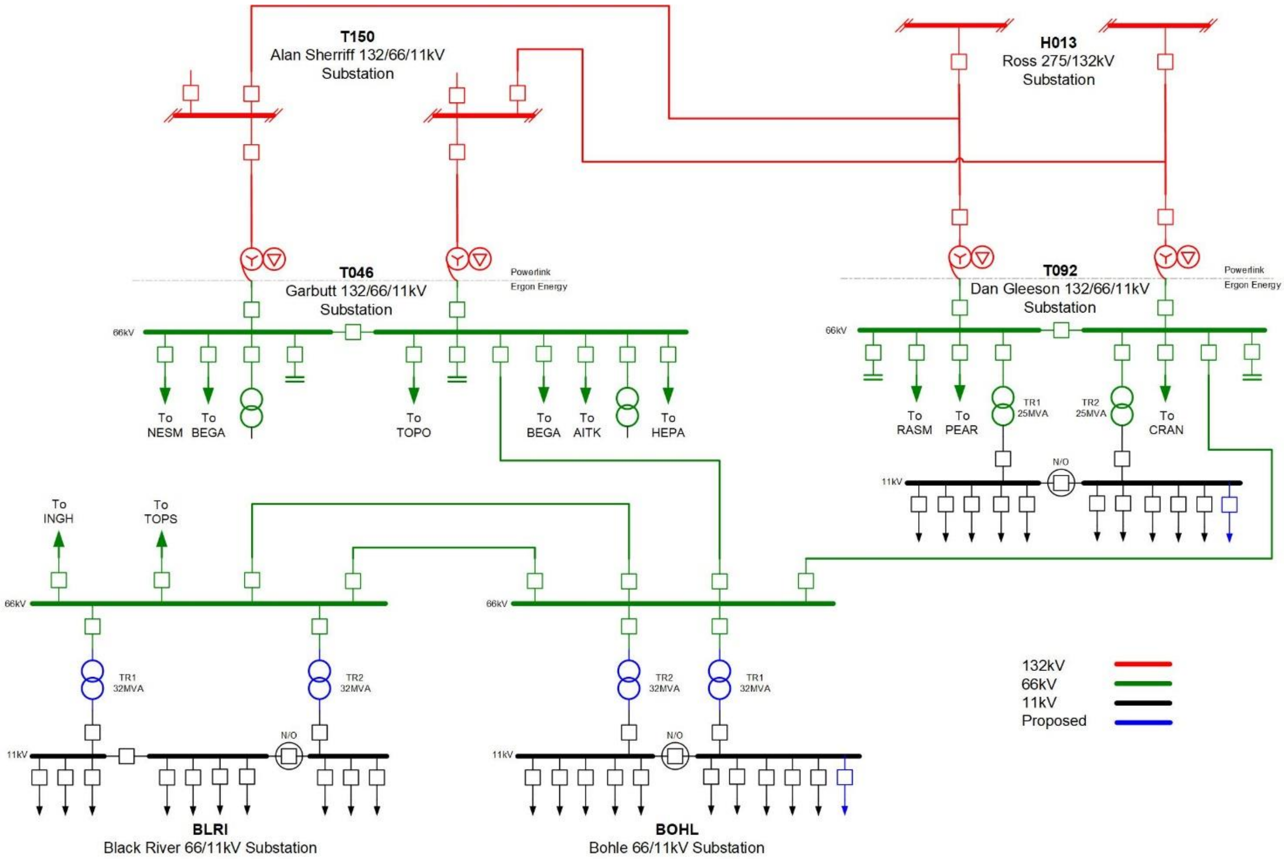


Figure 29: Option C proposed network arrangement (schematic view)

4.3. Preferred Network Option

Ergon Energy's preferred network option is Option A, to establish a new zone substation at Bohle Plains with 2 x 66kV feeder bays, 1 x 66kV transformer bay, 1 x 32MVA 66/11kV transformer, 11kV switchboard, establishment of 4 x 11kV feeders and reconfiguration of the BLRI, BOHL and DAGL 11kV network. Based on NPV calculations comparing all network options, this is the network option that provides the greatest net economic benefit.

Upon completion of these works, the identified need would be addressed.

The estimated capital cost of this option is $14.7 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in mid-2026 and construction completed by mid-2029.

5. TECHNICAL CHARACTERISTICS OF SAPS AND NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a Stand-alone Power System (SAPS) and/or a non-network option would be required to deliver, including:

- Size of load reduction or additional supply
- Location
- Contribution to power system security or reliability
- Contribution to power system fault levels as determined under clause 4.6.1 of the NER
- Operating profile

5.1. Size of load Reduction or Additional Supply

To address the identified need, it is expected that any SAPS or non-network option would provide load reduction or additional supply to the distribution network that supports a load up to the values listed in the tables below. Demand reduction or additional supply at both DAGL and BLRI must be provided in order to meet the identified need.

Year	Demand Reduction Required
2028	0.19 MVA
2029	0.31 MVA
2030	0.45 MVA
2031	0.6 MVA
2032	0.69 MVA
2033	0.79 MVA
2034	0.9 MVA
2035	1.2 MVA
2036	1.6 MVA
2037	2 MVA
2038	2.4 MVA
2039	2.7 MVA

Table 12: Demand reduction or additional supply required at DAGL (DG07 & DG10 feeders)

Year	Demand Reduction Required
2028	0.4 MVA
2029	1.4 MVA
2030	2.7 MVA
2031	4.1 MVA

2032	5.5 MVA
2033	6.6 MVA
2034	8.3 MVA
2035	9.7 MVA
2036	11.2 MVA
2037	12.6 MVA
2038	14 MVA
2039	15.4 MVA

Table 13: Demand reduction or additional supply required BLRI

5.2. Location

The location where network support and load restoration capability will be measured / referenced is on the DG07 and DG10 11kV feeders supplied from DAGL and on the BLRI 11kV network.

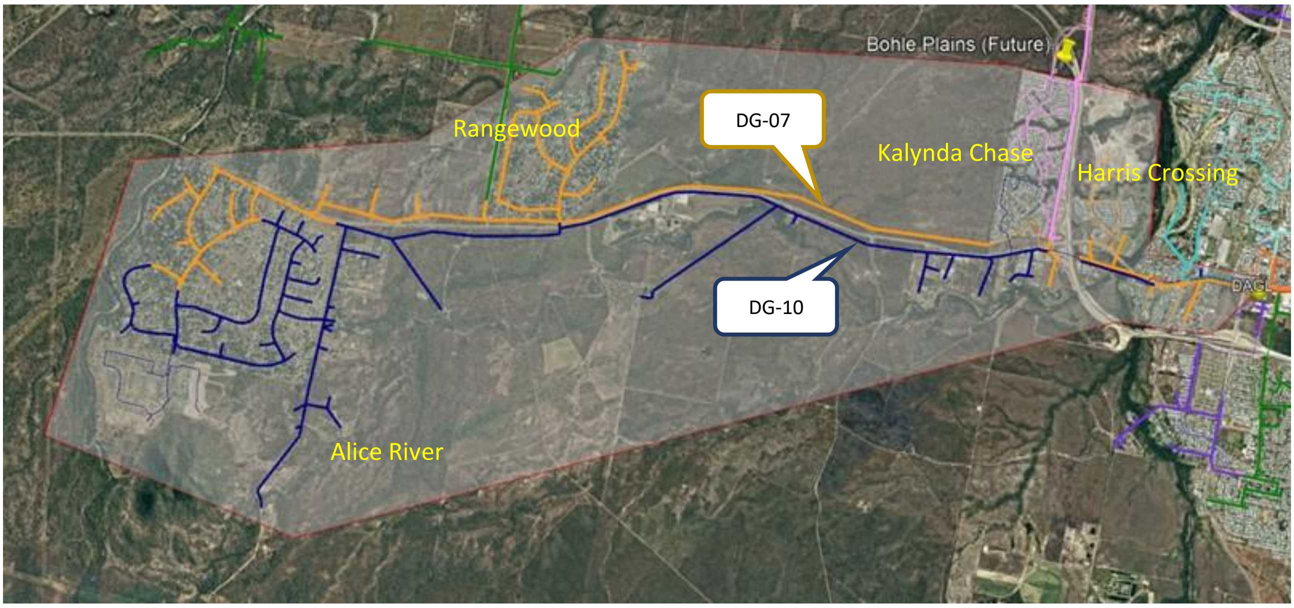


Figure 30: Location where network support is required for DAGL (DG07 & DG10 11kV feeders)

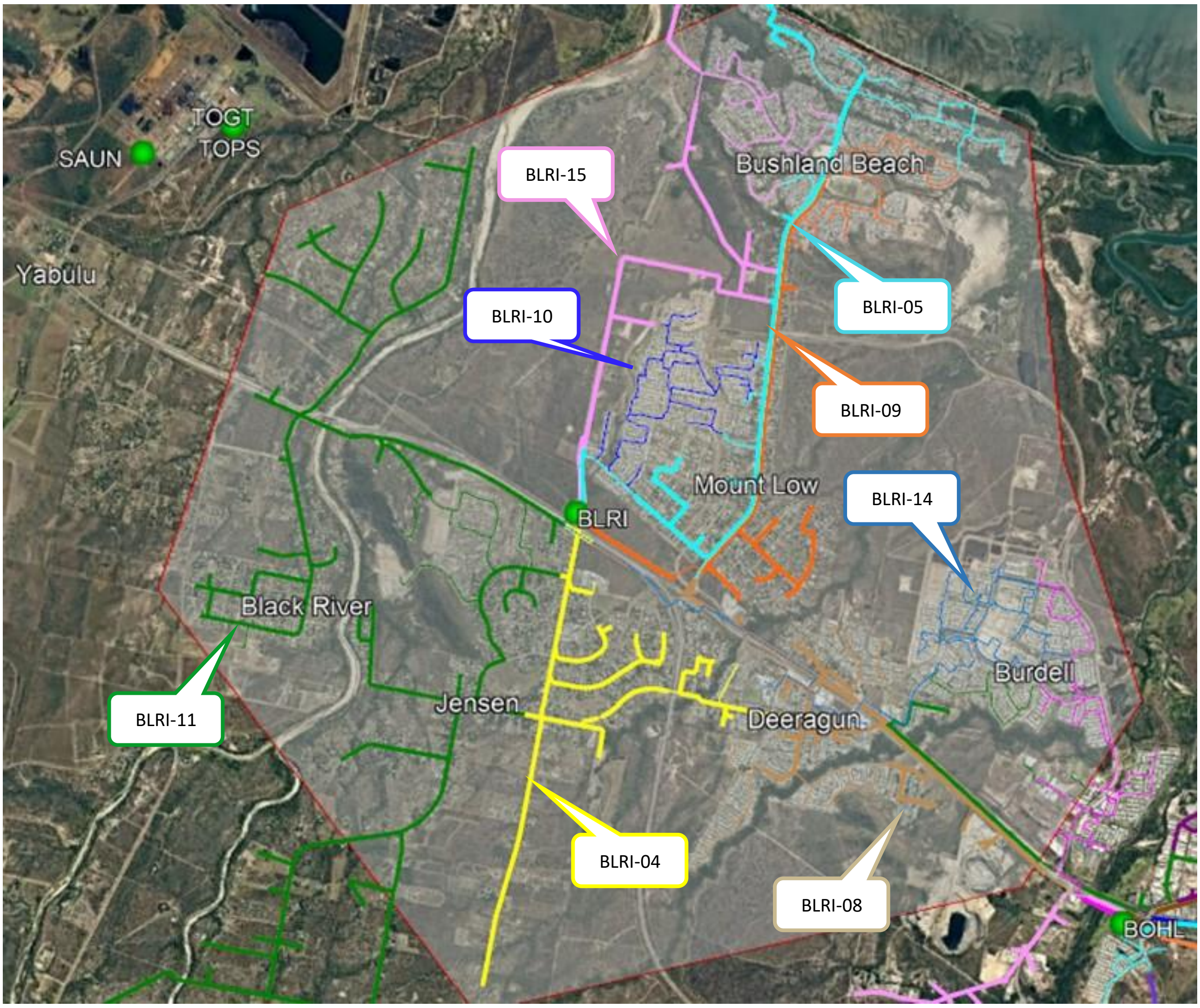


Figure 31: Location where network support is required for BLRI

5.3. Contribution to Power System Security and Reliability

In order to meet Ergon Energy's criteria under Safety Net the SAPS/non-network option would be required to provide the required level of network support in the specified location when requested.

The non-network option must also ensure that the reliability of the network in the location that support is being provided remains above the minimum service standard outlined in Section 3.2.

5.4. Contribution to Power System Fault Levels

The existing system normal maximum fault levels at BOHL, DAGL and BLRI are provided in Table 14, it is expected that a credible SAPS/non-network solution would not increase the network fault levels above plant ratings.

Location	3-Ph Fault Level (kA)	3-Ph Fault Level (MVA)	Ph-G Fault Level (kA)	Ph-G Fault Level (MVA)
BOHL 11kV Bus	10.97	209	11.52	73
BOHL 66kV Bus	12.68	1450	10.67	407
DAGL 11kV Bus	10.94	208	11.34	72
DAGL 66kV Bus	17.22	1968	19.79	754
BLRI 11kV Bus	7.84	149	8.19	52
BLRI 66kV Bus	10.13	1158	8.82	336

Table 14: Existing Maximum Fault Levels at BOHL, DAGL and BLRI

5.5. Operating Profile

The non-network option must be capable of continuous operation between 5pm and 10pm in order to reduce the peak demand (as outlined in section 5.1) sufficiently to negate the need for network investment. The solution must be available for immediate operation, when requested, for 99.8% of the time between October and March.

5.6. Timing

5.6.1. Implementation Timeframe

In order to ensure compliance with Ergon Energy's planning criteria and the National Electricity Rules, a SAPS/non-network solution will need to be implemented by October 2029.

5.6.2. Time of Year

Ergon Energy envisages that project proponents would be required to be available to provide the load reduction or additional supply between 5pm and 10pm during the October to March period for the number of days per year estimated in Table 6 and Table 10 for DAGL and Table 8 for BLRI.

5.6.3. Duration

Support would normally only be called upon following a fault on the network and the duration would vary depending on network repair times. Specific timing would be agreed with providers as part of the contract negotiations.

5.7. Compliance with Regulations and Standards

As a distribution network service provider (DNSP), Ergon Energy must comply with regulations and standards, including the *Electricity Act 1994* (Qld) and the Electricity Regulation 2006 (Qld), Distribution Authority, National Electricity Rules and applicable Australian Standards.

These obligations must be taken in consideration when choosing a credible solution to address the identified need in the Bohle Plains area as discussed in this RIT-D report.

5.8. Longevity

Proposed SAPS/non-network options will typically be required to provide solutions to the identified need for a period of at least 10 years. However, alternative solutions that can defer additional network investment for a smaller number of years may also be considered.

5.9. Potential Deferred Augmentation Charge

The annual deferred augmentation charge associated with the identified need is approximately $500k per year.

Ergon Energy have estimated the capital cost of the network options to within ± 40% of estimation accuracy. Using these costs as a guide, a deferral of the preferred network option by a year represents a deferral saving of approximately $500k per annum, assuming the same reliability outcomes are maintained as with the preferred network option. While this should not be considered as the precise deferral cost available to a non-network proponent, it serves as a guide for interested parties to determine the viability of their proposal. Ergon Energy will work with non-network proponents based on the specifics of what the proponents offer and any necessary further works that Ergon Energy may have to undertake to ensure the reliability, security and safety of the network are maintained.

6. SAPS AND NON-NETWORK OPTIONS

6.1. Assessment of SAPS and Non-Network Solutions

Ergon Energy's Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to defer the network option and determine if there is a viable demand management (DM) or SAPS option to replace or reduce the need for the network options proposed.

Credible options must be technically and commercially feasible and must be able to be implemented in sufficient time to satisfy the identified need.

6.1.1. Consideration of SAPS Options

Ergon Energy considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Bohle Plains region could not be supported by a network that is not part of the interconnected national electricity system.

6.1.2. Demand Management (Demand Reduction)

The DEM team has completed a review of the BOHL, DAGL and BLRI customer base and considered a number of demand management technologies.

Network Load Control

The residential customer load appears to drive the daily peak demand which generally occurs between 5:00pm and 10:00pm.

BOHL has 3465 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 2079kVA[3] is available.

DAGL has 6343 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3805kVA[4] is available.

BLRI has 6641 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3984kVA[5] is available.

LC signals in the Townsville area are controlled from T046 Garbutt 132/66kV Substation (GARB) and Stuart 66/11kV Substation (STUA). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable) and the current control strategy only calls LC when the T046 Garbutt 132/66kV Substation 66kV load exceeds 91MW or the T092 Dan Gleeson 132/66kV Substation 66kV load exceeds 110MW or the Stuart Substation 66kV load

[3] Hot water diversified demand saving estimated at 0.6kVA per system
[4] Hot water diversified demand saving estimated at 0.6kVA per system
[5] Hot water diversified demand saving estimated at 0.6kVA per system

exceeds 100MW. This strategy does not directly address demand peaks experienced at BLRI, BOHL or DAGL or the 11kV feeders. Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control alone does not sufficiently address the identified need.

6.1.3. 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. The primary driver for investment in this instance is asset safety and performance. 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).

This option has 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.

This option could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available.

Customer Solar Power Systems

BOHL has a total of 2,289 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 18,977kVA.

DAGL has a total of 4,463 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 26,233kVA.

BLRI has a total of 4,813 customers with solar photo voltaic (PV) systems with a total connected inverter capacity of 29,680kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 5:00pm and 10:00pm. As such customer solar generation does not coincide with the peak load period.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across fewer customers and therefore are cheaper and easier to engage and contract.

PV systems with BESS present a future portfolio opportunity for potential demand response. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

6.2. Feasible vs Non-Feasible Options

6.2.1. Potentially Feasible Options

The identified need presented in this RIT-D is driven by the capability of the existing sub-transmission and distribution network that supplies the Bohle Plains area. As such, solutions that cost-effectively provide increased contingency load restoration capability are likely to represent potential credible options.

A non-exhaustive list of potential options includes:

- New embedded dispatchable network generation
- Existing customer generation
- Embedded energy storage systems
- Load curtailment or “Call-off-load” opportunities (this refers to contracting existing customers to be partially or fully curtailed when called upon by Ergon Energy)

6.2.2. 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

6.2.3. 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 2029.

7. SUBMISSION AND NEXT STEPS

7.1. Submissions from Solution Providers

Ergon Energy invites written submissions to address the identified need in this report from registered participants and interested parties. With reference to Section 5, all submissions should include sufficient technical and financial information to enable Ergon Energy to undertake comparative analysis of the proposed solution against other options.

The proposals shall include, but are not limited to, at least the following:

- Full costs of completed works.
- Whole of life costs including losses.
- Project execution strategy including design, testing and commissioning plans.
- Engineering network system studies and study reports.
- Verified and approved engineering designs.
- Manufacture and supply of all plant, equipment and materials.
- Delivery to site, receiving and off-loading of all plant, equipment and materials.
- Assembly and installation on site.

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 SAPS and 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 in accordance with Ergon Energy's standards for procurement.

Submissions in writing are due by 4pm on the **31 January 2025** and should be lodged to demandmanagement@ergon.com.au

7.2. Next Steps

Ergon Energy intends to carry out the following process to assess what action should be taken to address the identified need in the Bohle Plains supply area:

Step 1	Publish Options Screening Report (this report) inviting SAPS and non-network options from interested participants	Date Released: **22 October 2024**
Step 2	Consultation period	**Minimum of 3 months (12 weeks)**

Step 3	Deadline for Submission of proposals for SAP and non-network alternatives	**31 January 2025**
Step 4	Release of Draft Project Assessment Report (DPAR)	Anticipated to be released by: **14 February 2025**
Step 5	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 6	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **4 April 2025**
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.

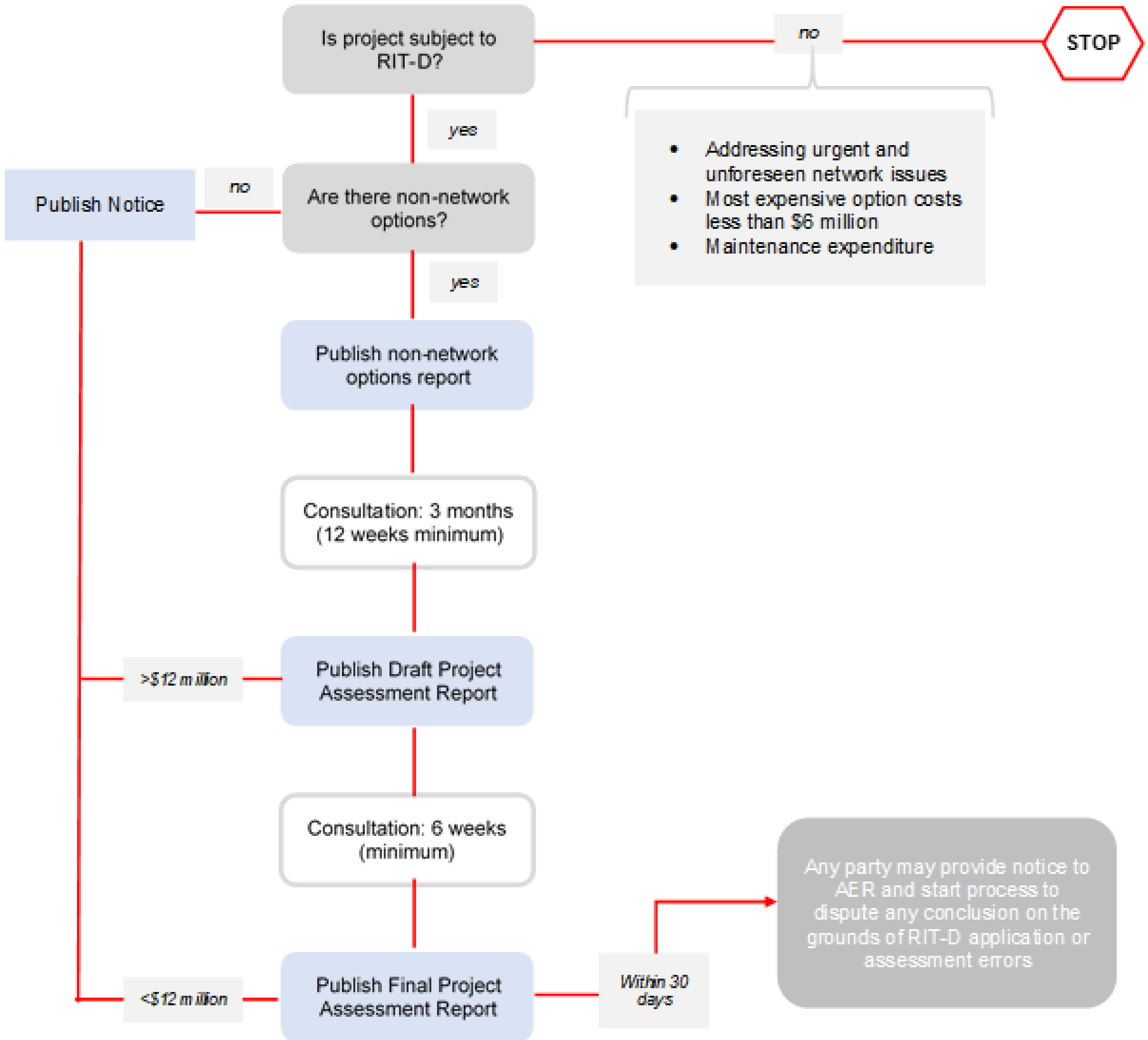
8. COMPLIANCE STATEMENT

This Non-Network Options Report complies with the requirements of NER section 5.17.4(e) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need;	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) if available, the relevant annual deferred *augmentation* charge associated with the identified need;	5.9
(4) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of *load* reduction or additional *supply*; (ii) location; (iii) contribution to *power system security* or *reliability*; (iv) contribution to *power system* fault levels as determined under clause 4.6.1; and (v) the operating profile;	2.3 & 5

(5) a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options;	4 & 6
(6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on: (i) a technical definition or characteristics of the option; (ii) the estimated construction timetable and commissioning date (where relevant); and (iii) the total indicative cost (including capital and operating costs); and	4 & 6
(7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a non-network proposal for consideration by the RIT-D proponent.	7

APPENDIX A – THE RIT-D PROCESS



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