



Regulatory Investment Test for Distribution (RIT-D)

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

2 May 2025



Part of Energy Queensland

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

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 Authority¹ issued under the *Electricity Act 1994* (Qld)²). The forecast loading for the

¹ Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

² QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

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

The Local Renewable Energy Zone (LREZ) pilot project 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 Bohle Plains area falls within the Townsville LREZ. 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 RIT-D Report outlines. For that reason, the steps required as part of the RIT-D 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 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.

Ergon Energy published a Draft Project Assessment Report for the identified need in the Bohle Plains area on 7 March 2025. No submissions were received by the closing date of 24 April 2025.

Three potentially feasible options have been investigated:

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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

- **Option B:** Establish Bohle Plains Zone Substation with two 66/11kV transformers.
- **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 Final Project Assessment Report (FPAR), has been prepared in accordance with the requirements of clause 5.17.4 of the NER.

Ergon Energy's preferred solution to address the identified need 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.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

CONTENTS

Executive Summary	2
About Ergon Energy	2
Identified Need.....	2
Local Renewable Energy Zones – Townsville	3
Approach.....	3
1. Introduction.....	8
1.1. Response to the DPAR	8
1.2. Structure of the Report.....	8
1.3. Dispute Resolution Process	9
1.4. Contact Details	9
2. Background	10
2.1. Geographic Region.....	10
2.2. Existing Supply System.....	11
2.3. Load Profiles / Forecasts	13
2.3.1. Full Annual Load Profile	13
2.3.2. Load Duration Curve.....	15
2.3.3. Average Peak Weekday Load Profile (Summer).....	16
2.3.4. Average Load/Generation Profiles for 11kV feeders and Bohle BESS.....	18
2.3.5. Base Case Load Forecast	20
2.3.6. High Growth Load Forecast	22
2.3.7. Low Growth Load Forecast	23
3. Identified Need.....	26
3.1. Description of the Identified Need	26
3.1.1. Reliability Corrective Action.....	26
3.2. Quantification of the Identified Need.....	26
3.2.1. Safety Net Non-Compliance.....	26
3.2.2. Risk Quantification Value Streams	31
3.2.3. Counterfactual Risk Quantification	32
3.3. Assumptions in Relation to Identified Need.....	34
3.3.1. Forecast Maximum Demand	35
3.3.2. Load Profile.....	35
3.3.3. Network Batteries.....	35

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

4.	Credible Options Assessed	36
4.1.	Assessment of Network Solutions	36
4.1.1.	Option A: Establish Bohle Plains Zone Substation with a single 66/11kV transformer 36	
4.1.2.	Option B: Establish Bohle Plains Zone Substation with two 66/11kV transformers .	37
4.1.3.	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.....	38
4.2.	Assessment of SAPS and Non-Network Solutions	39
4.2.1.	Consideration of SAPS Options	39
4.2.2.	Demand Management (Demand Reduction)	40
4.2.3.	Demand Response.....	40
4.2.4.	SAPS and Non-Network Solution Summary.....	42
4.3.	Preferred Option.....	42
5.	Summary of Submissions Received in Response to the Draft Project Assessment Report	43
6.	Market Benefit Assessment Methodology	43
6.1.	Classes of Market Benefits Considered and Quantified	43
6.1.1.	Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages	43
6.2.	Classes of Market Benefits not Expected to be Material.....	44
6.2.1.	Changes in Voluntary Load Curtailment	44
6.2.2.	Changes in Costs to Other Parties	44
6.2.3.	Differences in Timing of Expenditure	44
6.2.4.	Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load.....	44
6.2.5.	Changes in Electrical Energy Losses.....	44
6.2.6.	Changes in Australia's Greenhouse Gas Emissions.....	45
6.2.7.	Option Value.....	45
6.2.8.	Costs Associated with Social Licence Activities	45
7.	Detailed Economic Assessment	46
7.1.	Methodology.....	46
7.2.	Key Variables and Assumptions.....	46
7.3.	Scenarios Adopted for Sensitivity Testing.....	46
7.4.	Net Present Value (NPV) Results.....	47
8.	Conclusion.....	49
8.1.	Preferred Option.....	49



Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

8.2.	Satisfaction of RIT-D.....	49
9.	Compliance Statement.....	50
Appendix A – The Rit-D Process		51

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

1. INTRODUCTION

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

This FPAR represents the final 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. Response to the DPAR

Ergon Energy published a Draft Project Assessment Report for the identified need in the Bohle Plains network area on 7 March 2025. No submissions were received by the closing date of 24 April 2025.

1.2. 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 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.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- 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 each credible option and accompanying explanatory statements regarding the results.
- 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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

1.3. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5 of the NER, Registered Participants and other interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred network option, 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.

1.4. Contact Details

For further information and inquiries please contact:

E: demandmanagement@ergon.com.au

P: 13 74 66

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

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.

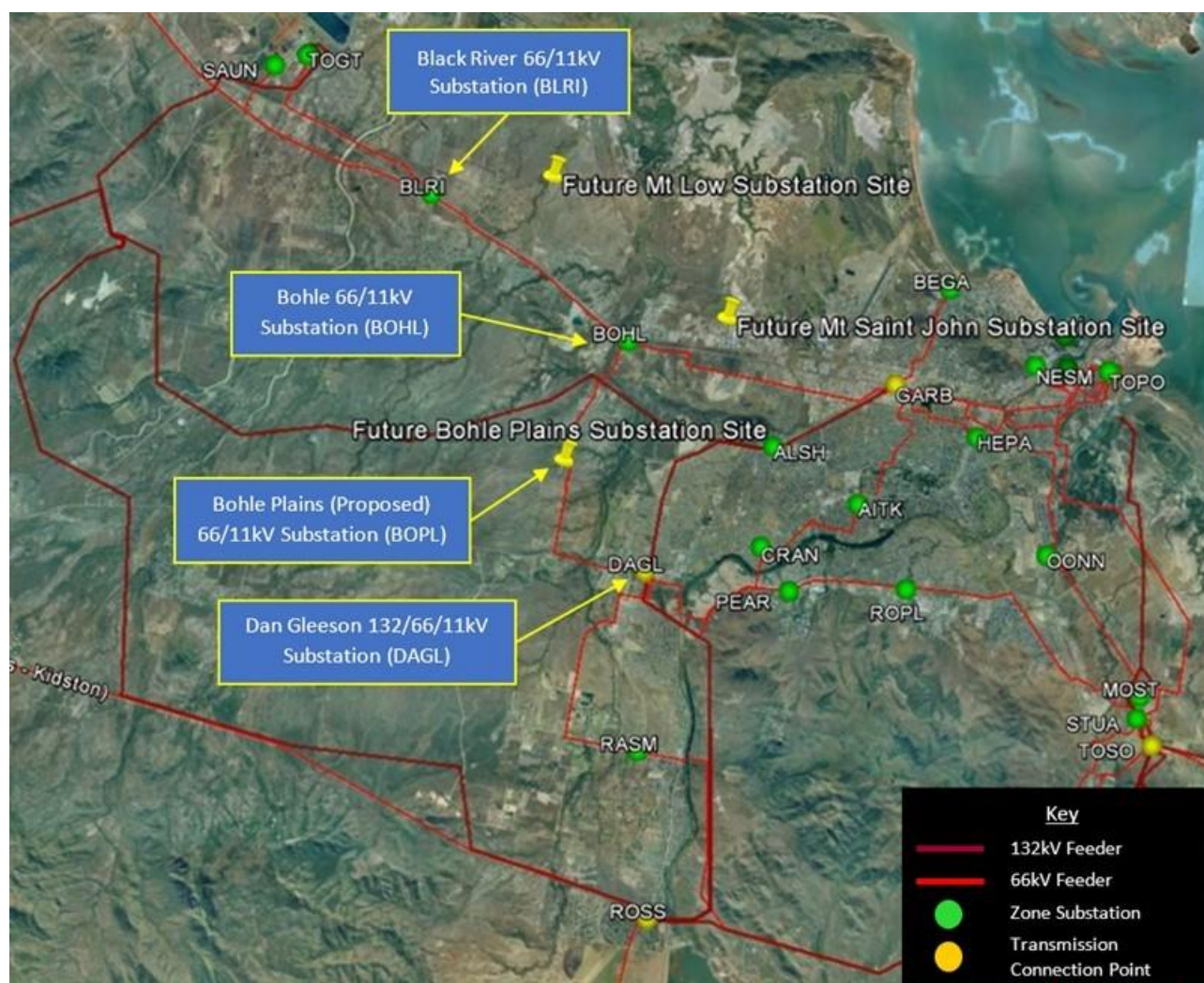


Figure 1: Existing network arrangement (geographic view)

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

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 Plan³. 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 the distribution network arrangement is illustrated in Figure 3.

³ <https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries>



Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report



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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

substations occurs during the Summer evening period and the minimum load at these substations occurs during the Winter and Spring midday periods.

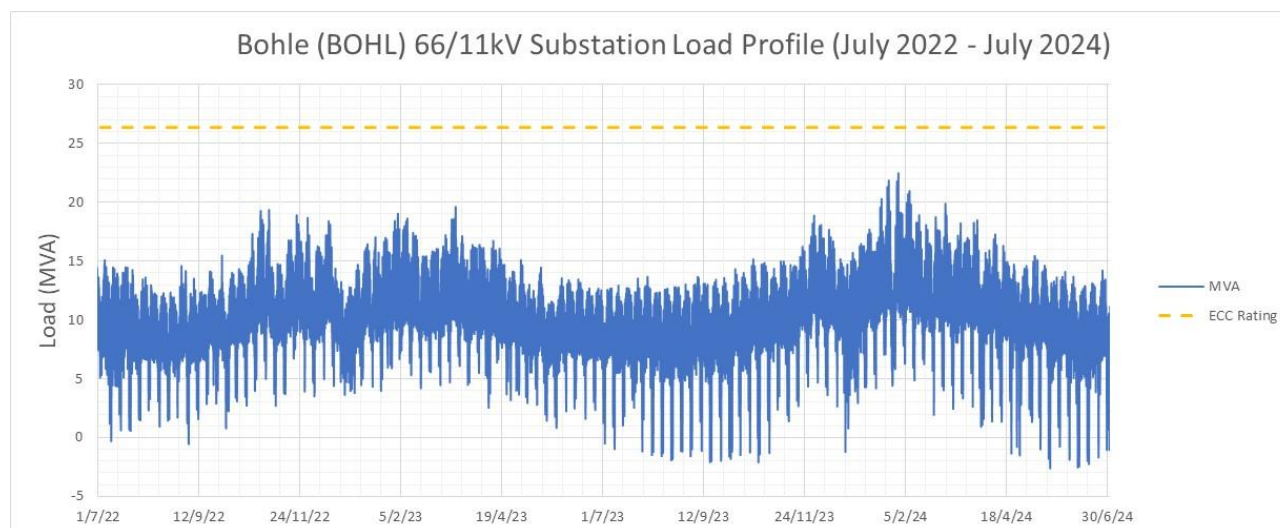


Figure 4: BOHL Substation 11kV load profile for period July 2022-July 2024

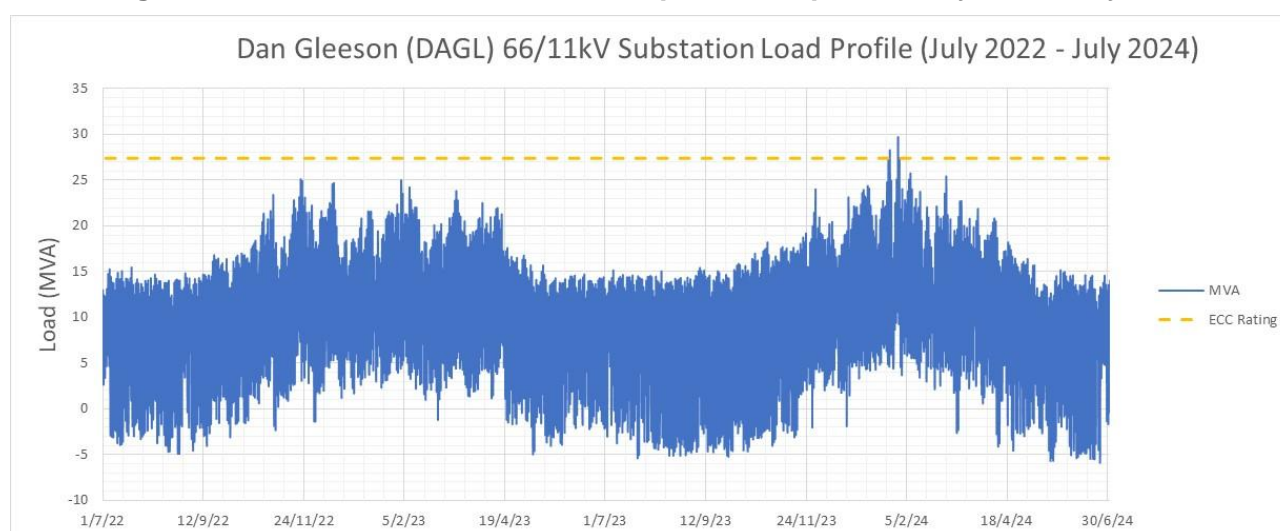


Figure 5: DAGL Substation 11kV load profile for period July 2022-July 2024

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

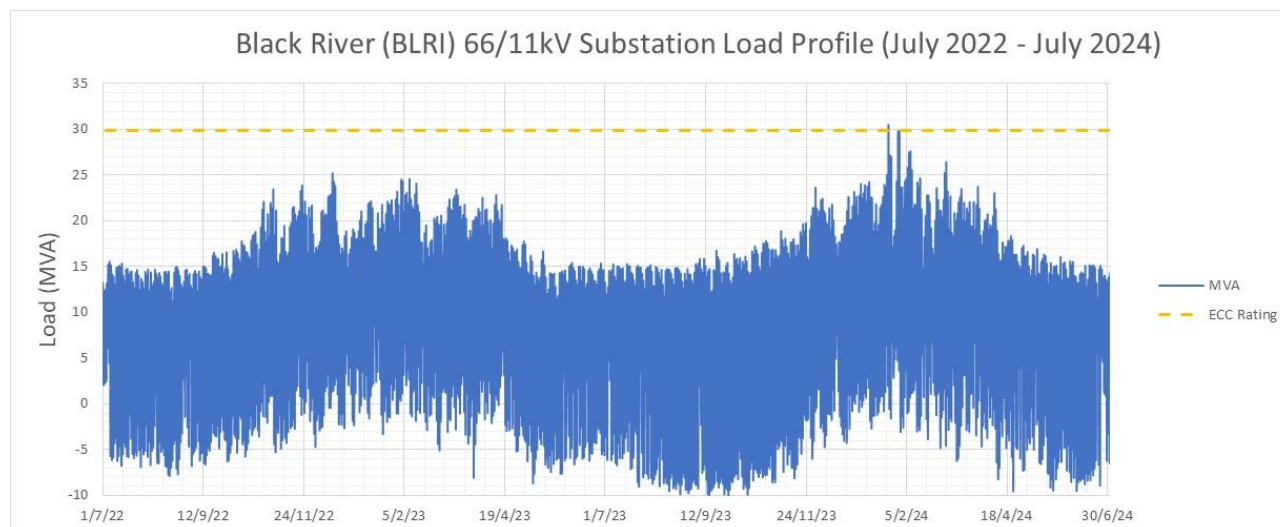


Figure 6: BLRI Substation 11kV load profile for period July 2022-July 2024

2.3.2. Load Duration Curve

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

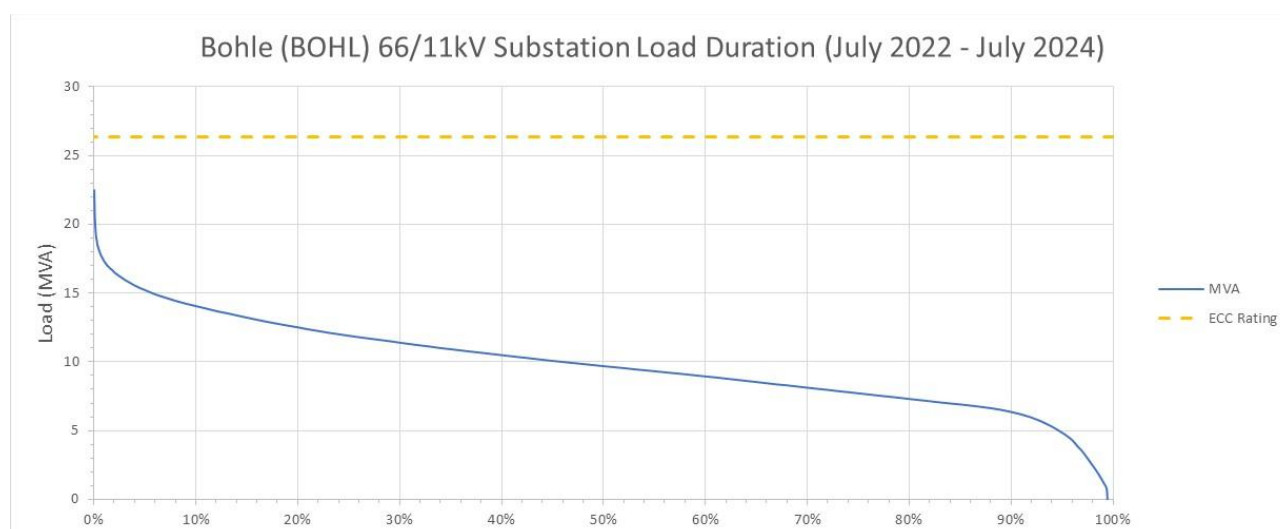


Figure 7: BOHL Substation 11kV load duration curve for period July 2022-July 2024

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

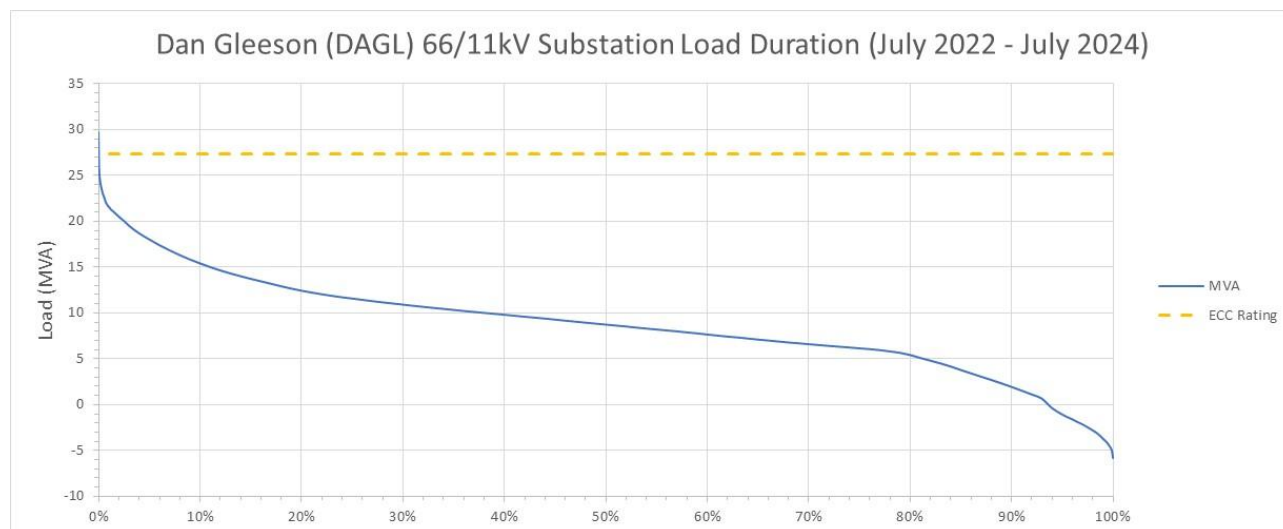


Figure 8: DAGL Substation 11kV load duration curve for period July 2022-July 2024

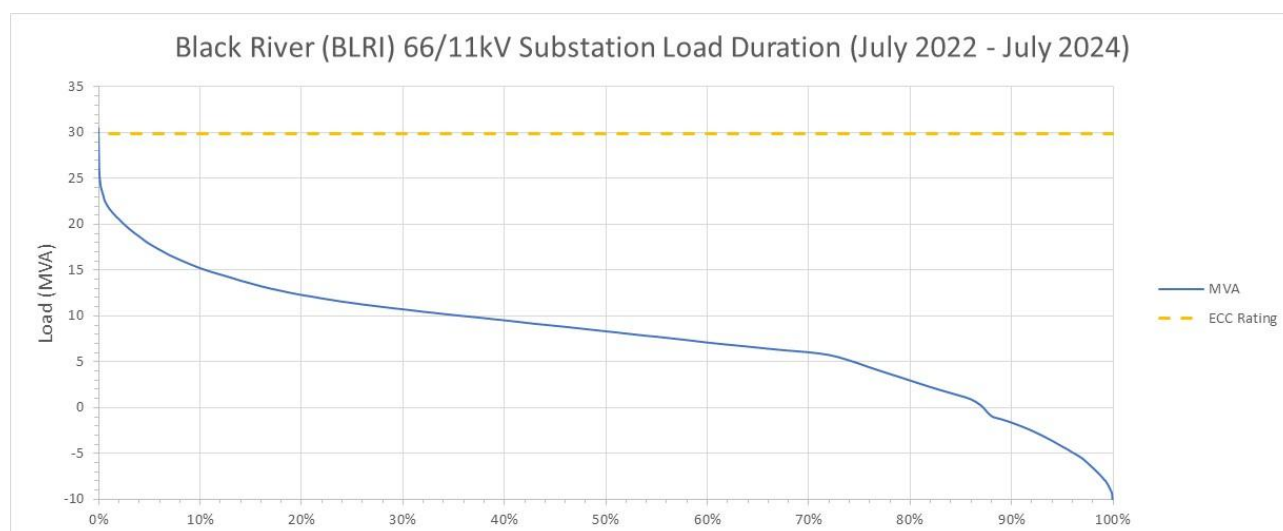


Figure 9: BLRI Substation 11kV load duration curve for period July 2022-July 2024

2.3.3. Average Peak Weekday 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.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

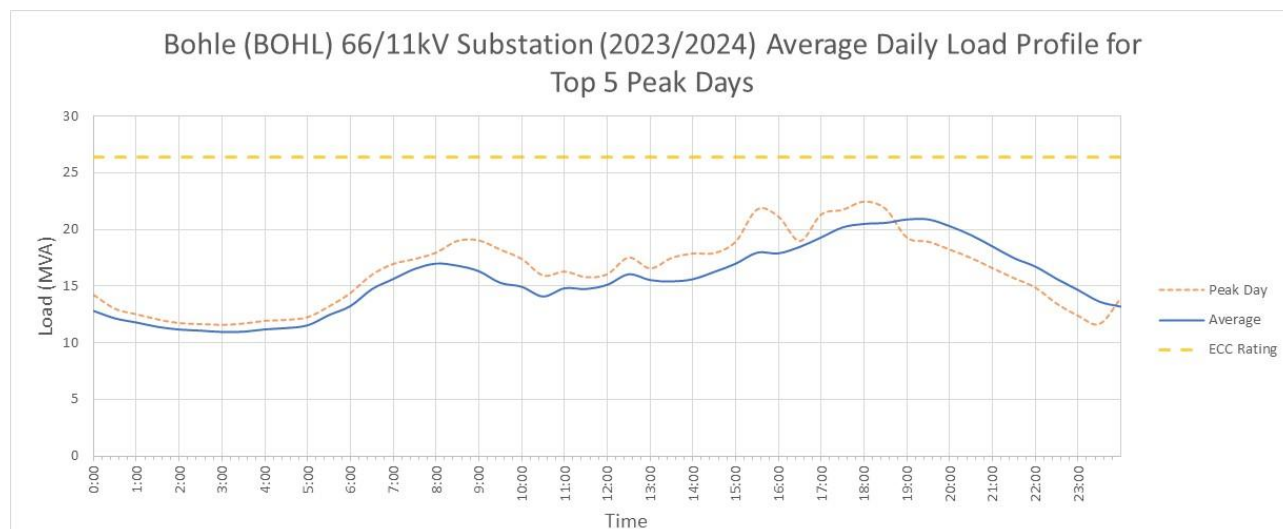


Figure 10: BOHL Substation average peak 11kV load profile (summer)

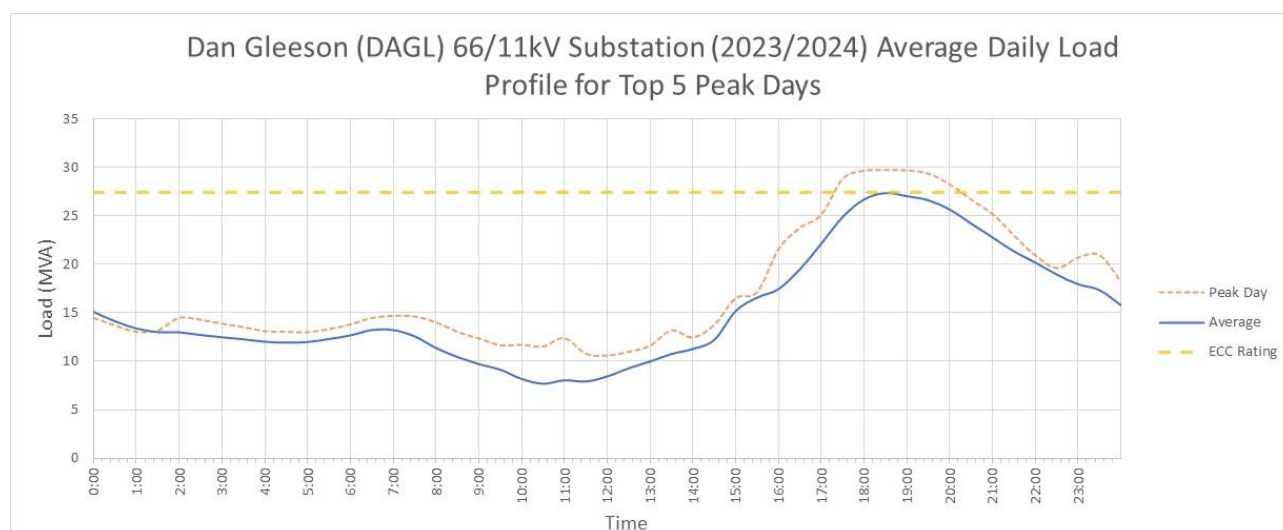


Figure 11: DAGL Substation average peak 11kV load profile (summer)

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

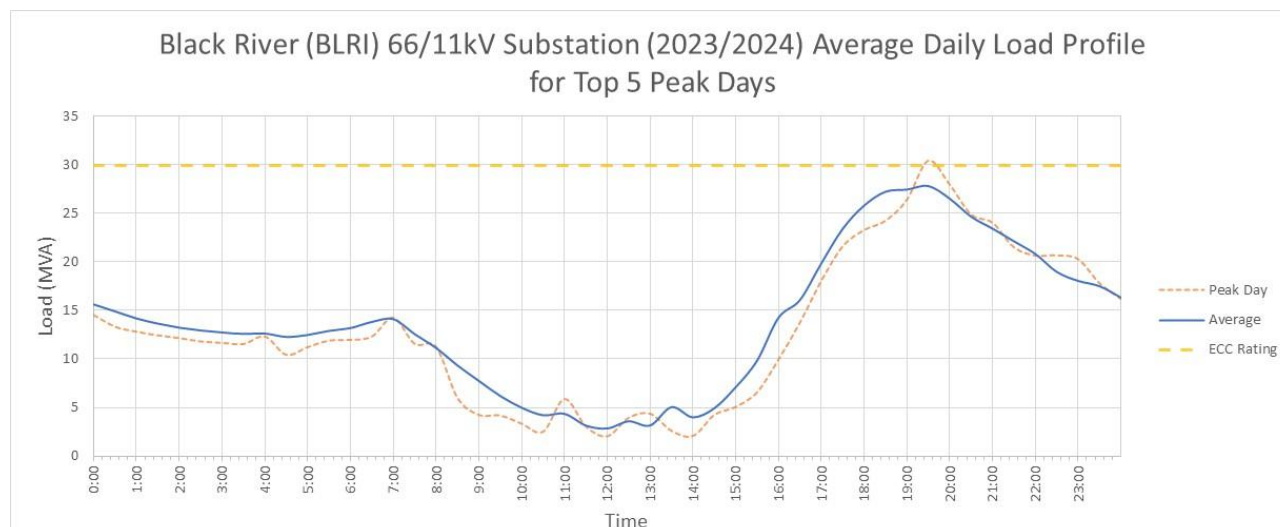


Figure 12: BLRI Substation average peak 11kV load profile (summer)

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

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

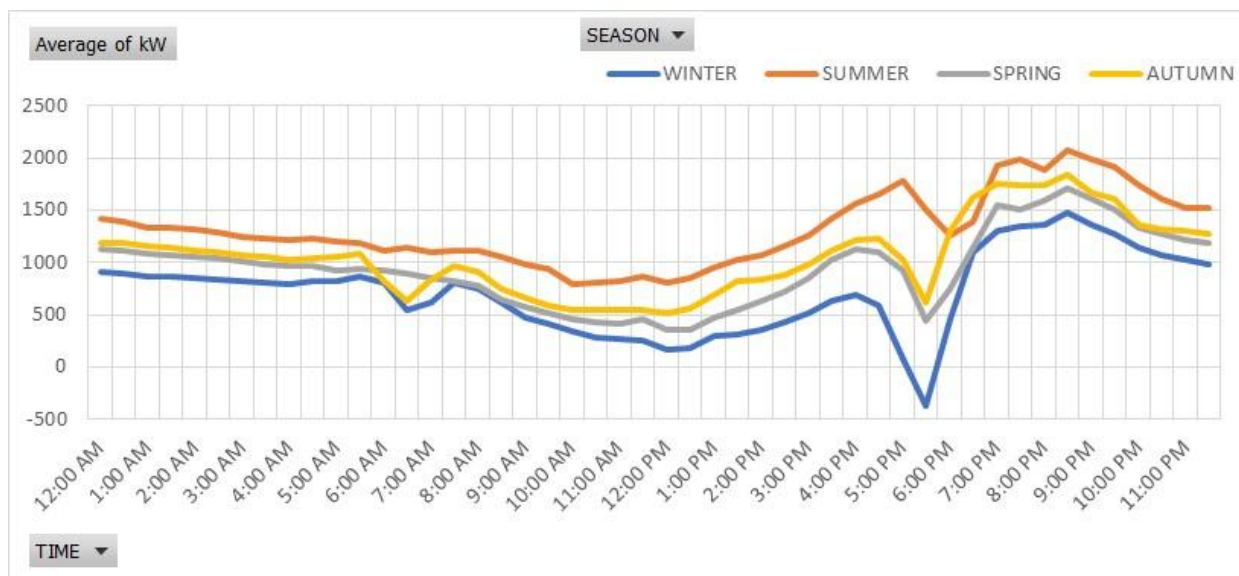


Figure 14: BO10 11kV feeder average load profile (Bohle BESS is connected to this feeder)

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

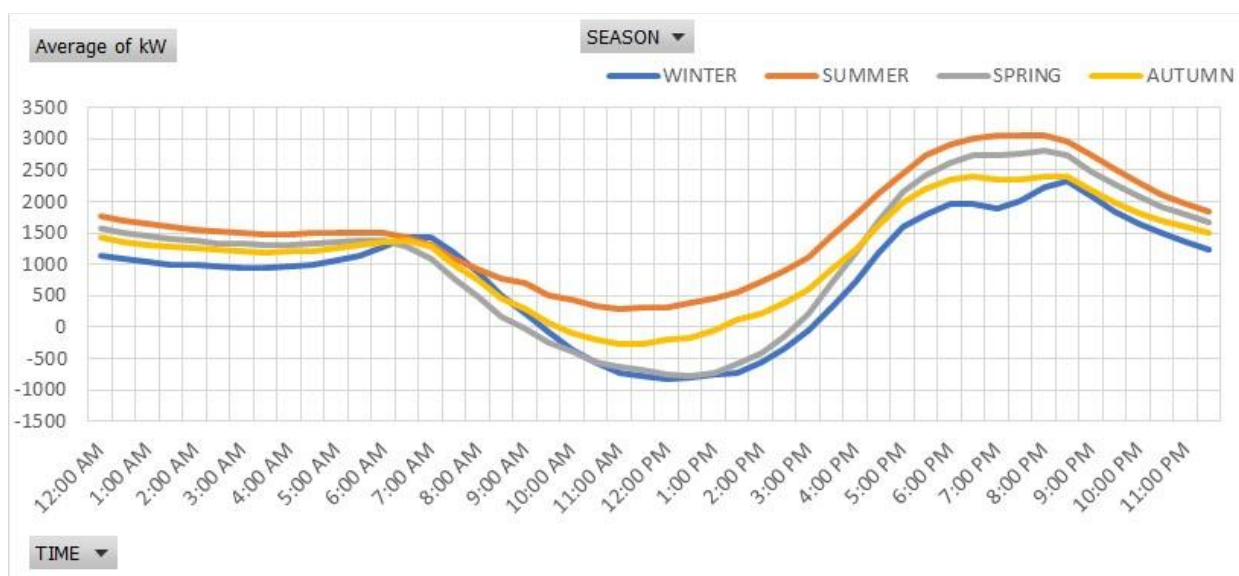


Figure 15: DG07 11kV feeder average load profile

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report



Figure 16: DG10 11kV feeder average load profile

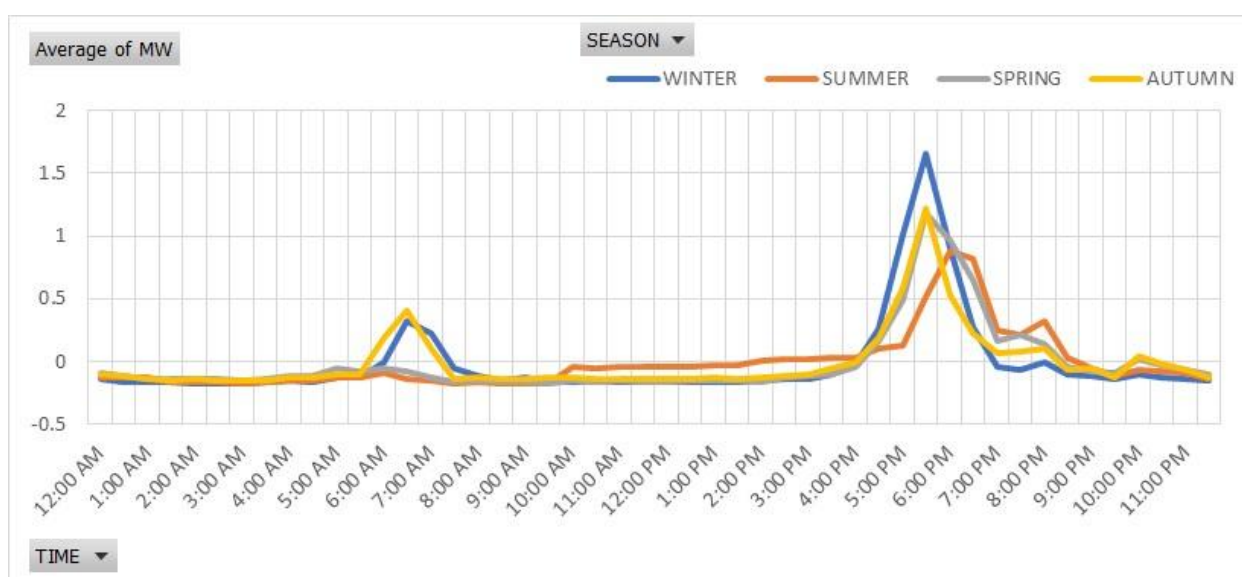


Figure 17: Bohle BESS average 11kV load/generation profile (positive = generation)

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 graph.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

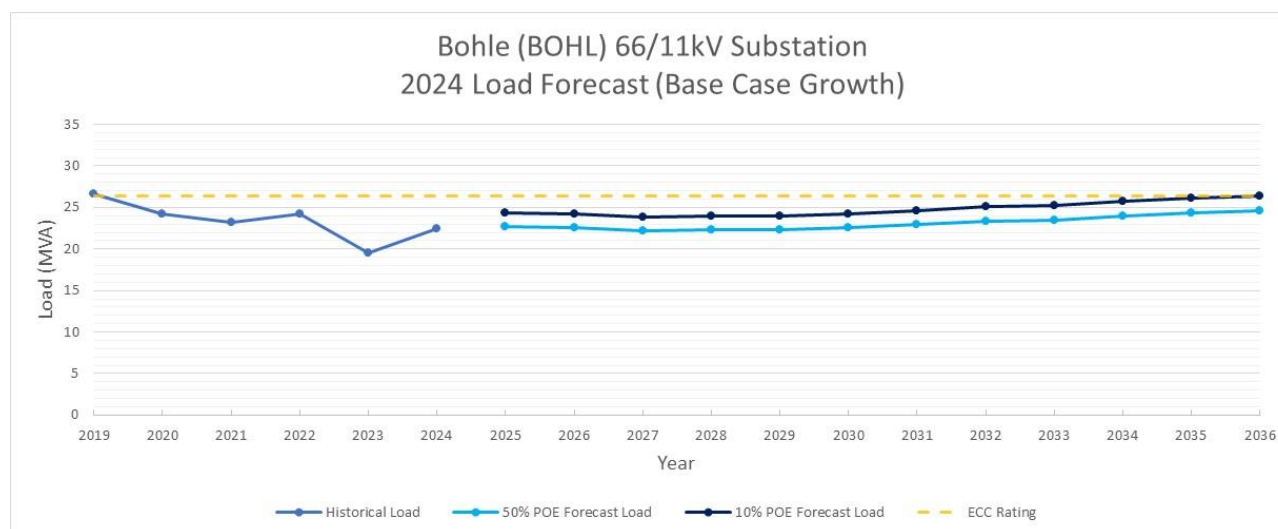


Figure 18: BOHL Substation base case 11kV load forecast

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.

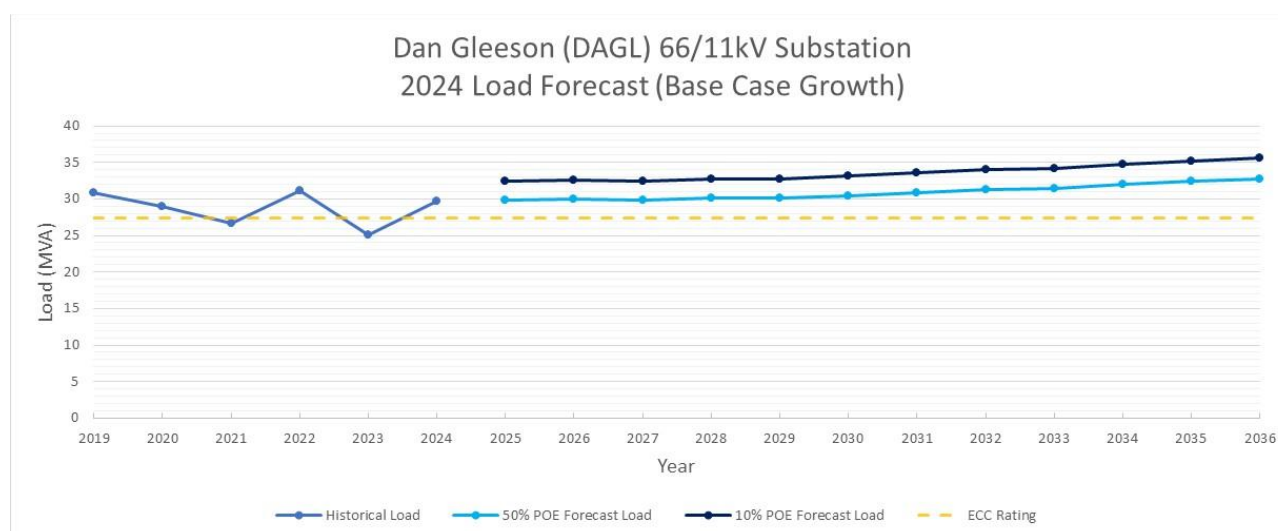


Figure 19: DAGL Substation base case 11kV load forecast

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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

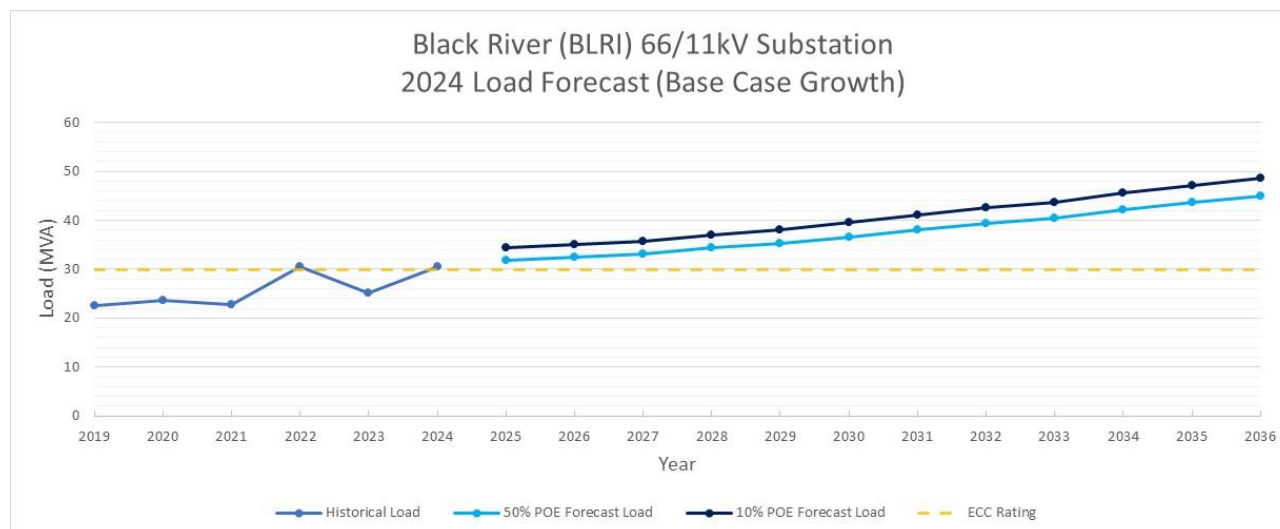


Figure 20: BLRI Substation base case 11kV load forecast

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.

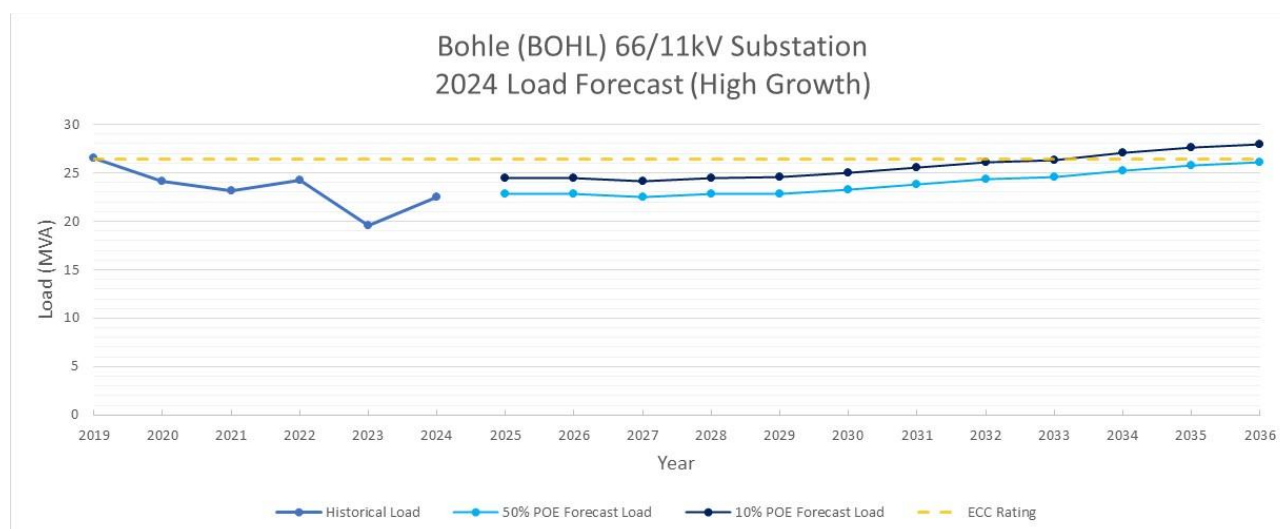


Figure 21: BOHL Substation high growth 11kV load forecast

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

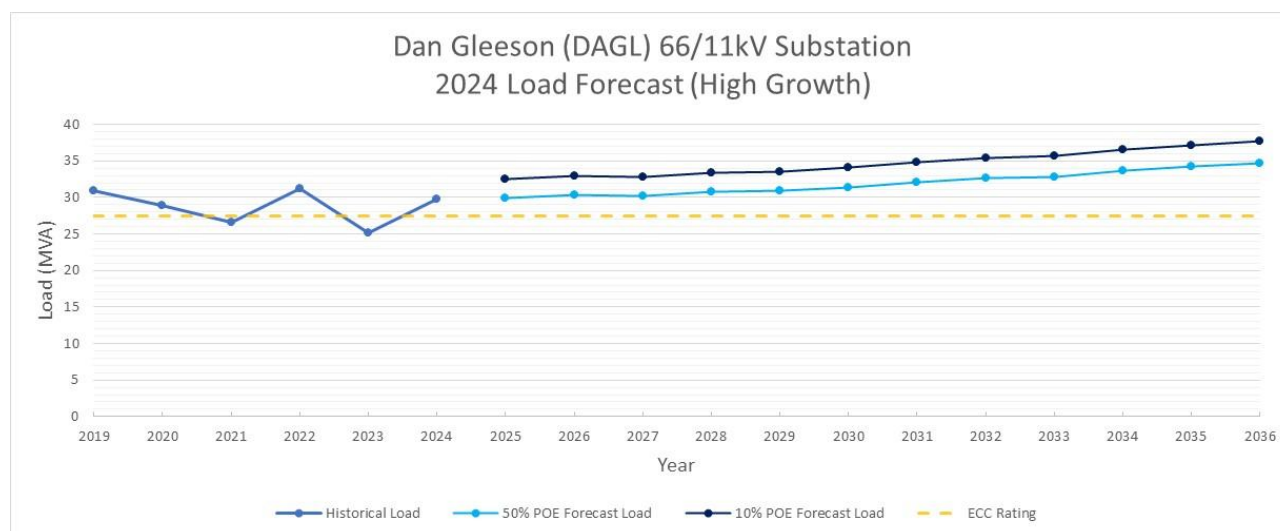


Figure 22: DAGL Substation high growth 11kV load forecast

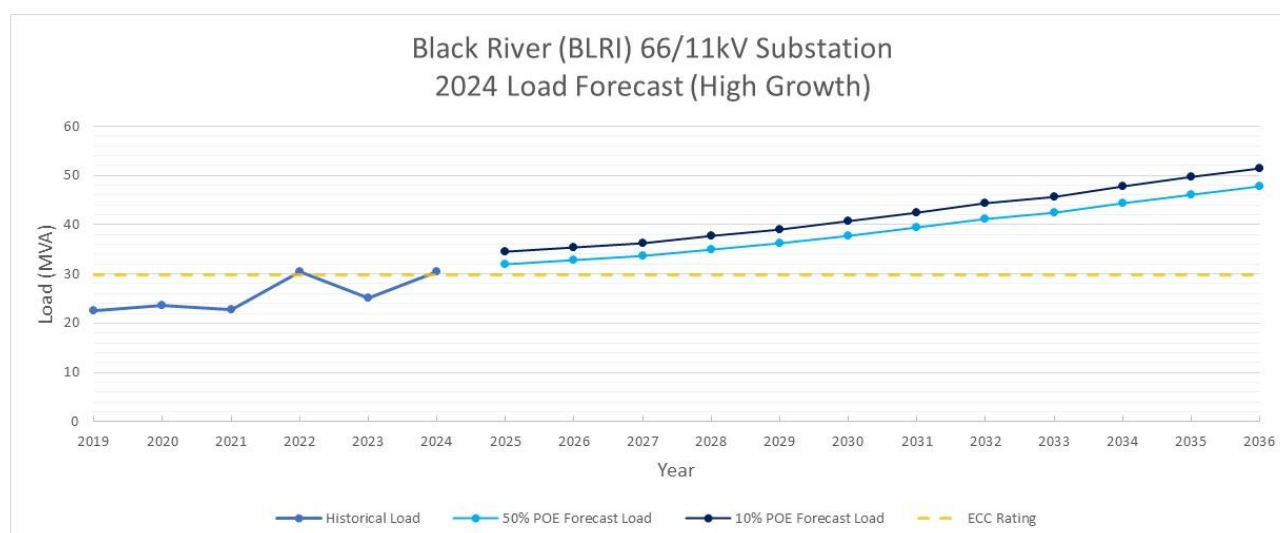


Figure 23: BLRI Substation high growth 11kV load forecast

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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

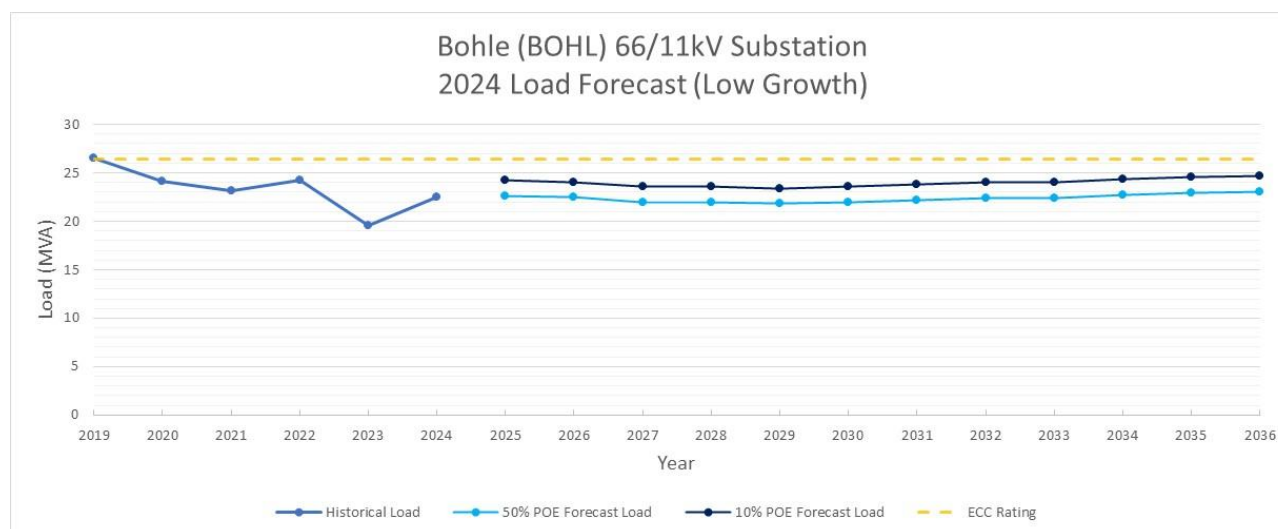


Figure 24: BOHL Substation low growth 11kV load forecast

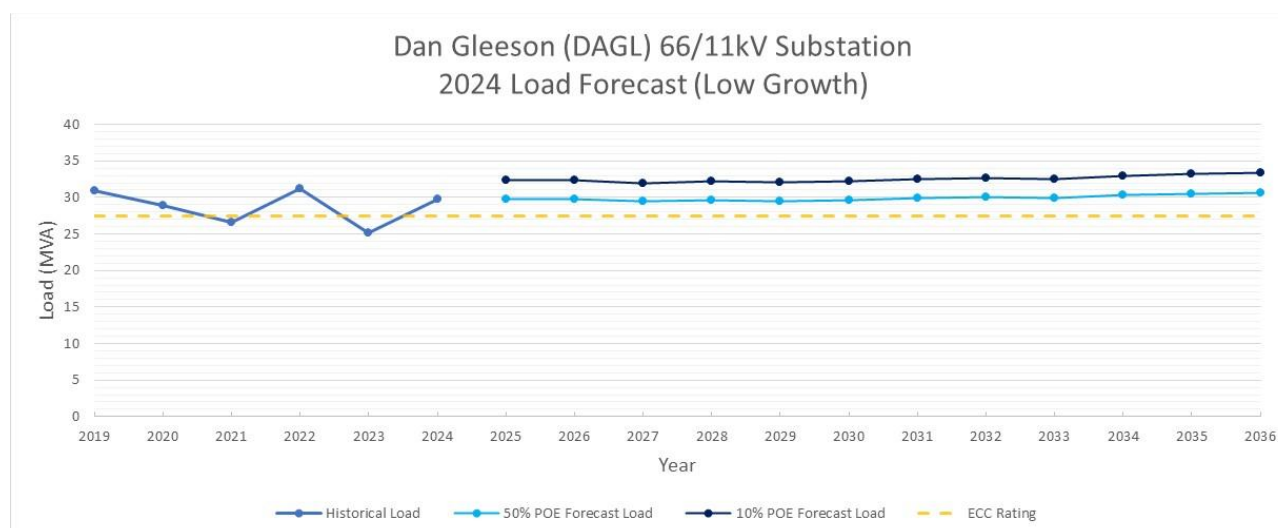


Figure 25: DAGL Substation low growth 11kV load forecast

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

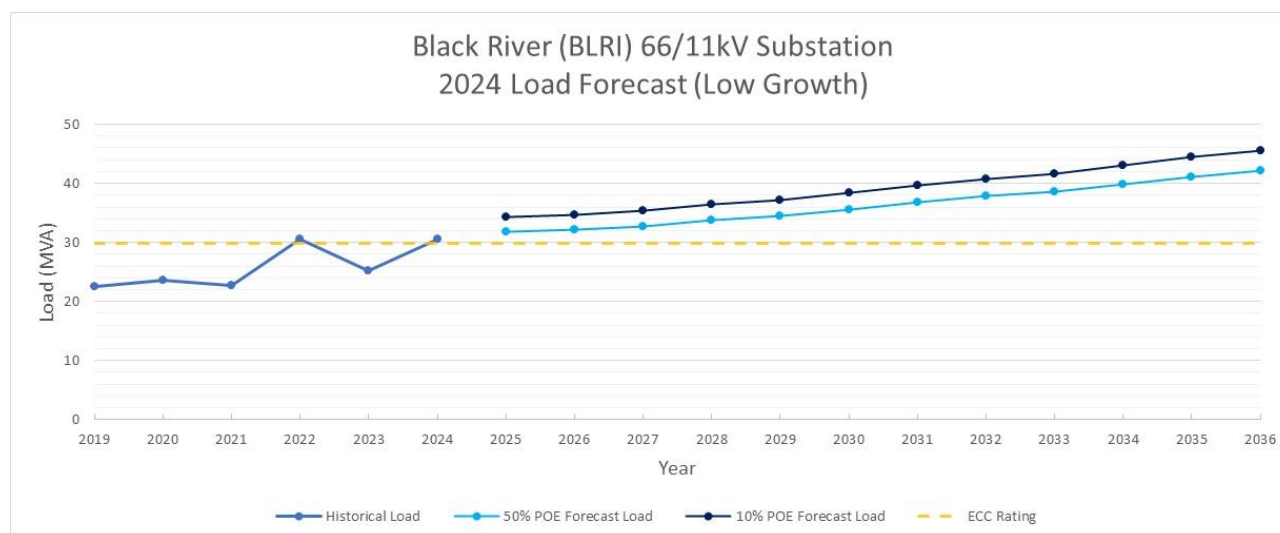


Figure 26: BLRI Substation low growth 11kV load forecast

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

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 imposed in its Distribution Authority⁴ issued under the *Electricity Act 1994* (Qld)⁵). 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. Quantification of the Identified Need

The benefits of each credible option are assessed against the counterfactual, which in this case is to continue to operate the network with existing in-service assets.

3.2.1. 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 1 and Table 2. 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

⁴ Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

⁵ QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

generation if required. This assessment assumes that the Bohle 4MW / 8MWh BESS would be exporting and that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If the BESS, load transfer capacity and mobile generation are not available at the time of the contingency the load at risk levels specified in Table 1 and Table 2 would increase. As load continues to grow on the 11kV distribution network the transfer capacity is likely to reduce.

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 1: BOHL Base Case Growth 50PoE Forecast Load at Risk

Table 1 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a base case growth scenario with existing load transfer capacity, BESS export and mobile generation deployment.

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 2: BOHL High Growth Case 50PoE Forecast Load at Risk

Table 2 illustrates that there is no load at risk forecast at BOHL substation prior to 2039 under a high growth scenario with existing load transfer capacity, BESS export and mobile generation deployment.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

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 3 and Table 4. 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. This assessment assumes that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If load transfer capacity and mobile generation are not available at the time of the contingency the load at risk levels specified in Table 3 and Table 4 would increase. As load continues to grow on the 11kV distribution network the transfer capacity is likely to reduce.

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 3: DAGL Base Case Growth 50PoE Forecast Load at Risk

Table 3 illustrates the amount and duration of support required at DAGL under a base case growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.1MVA for 1 day in 2032 increasing to 2.7MVA for 5 days in 2039.

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

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

Table 4: DAGL High Growth Case 50PoE Forecast Load at Risk

Table 4 illustrates the amount and duration of support required at DAGL under a high growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.2MVA for 1 day in 2030 increasing to 5.2MVA for 15 days in 2039.

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 5 and Table 6. 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 assumes that the Black River 4MW / 8MWh BESS would be exporting and that load transfer capacity and mobile generation will be available in the event of a contingency during the peak load period. If the BESS, load transfer capacity and mobile generation are not available at the time of the contingency the load at risk levels specified in Table 5 and Table 6 would 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 5: BLRI Base Case Growth 50PoE Forecast Load at Risk

Table 5 illustrates the amount and duration of support required at BLRI under a base case growth scenario with existing load transfer capacity, BESS export and mobile generation deployment, starting at 0.4MVA for 1 day in 2028 increasing to 15.4MVA for 113 days in 2039.

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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

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 6: BLRI High Growth Case 50PoE Forecast Load at Risk

Table 6 illustrates the amount and duration of support required at BLRI under a high growth scenario with existing load transfer capacity, BESS export and mobile generation deployment, starting at 1.1MVA for 3 days in 2028 increasing to 18.9MVA for 150 days in 2039.

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 7 and Table 8. 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. As load continues to grow on the 11kV distribution network the transfer capacity to adjacent feeders is likely to reduce.

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

Table 7 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a base case growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.19MVA for 1 day in 2028 increasing to 1.51MVA for 7 days in 2039.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

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

Table 8 illustrates the amount and duration of support required for the DG07 & DG10 feeders under a high growth scenario with existing load transfer capacity and mobile generation deployment, starting at 0.22MVA for 1 day in 2028 increasing to 1.58MVA for 7 days in 2039.

3.2.2. Risk Quantification Value Streams

The risk quantification of the counterfactual at Bohle Plains has considered three primary value streams, *reliability*, *financial* and *export*, as shown in Figure 27 and described in further detail below.

- **Reliability:** There is potential unserved energy within the Bohle Plains area following an outage on a substation transformer or 11kV distribution feeder due to limited backup transfer capacity.
- **Financial:** Replacing single assets on failure as individual failed in-service projects has been assumed to incur a 30% increase in cost in comparison to a planned project.
- **Export:** There is potential customer export curtailment within the Bohle Plains area under system normal conditions and following an outage on a substation transformer or 11kV distribution feeder due to limited backup transfer capacity.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

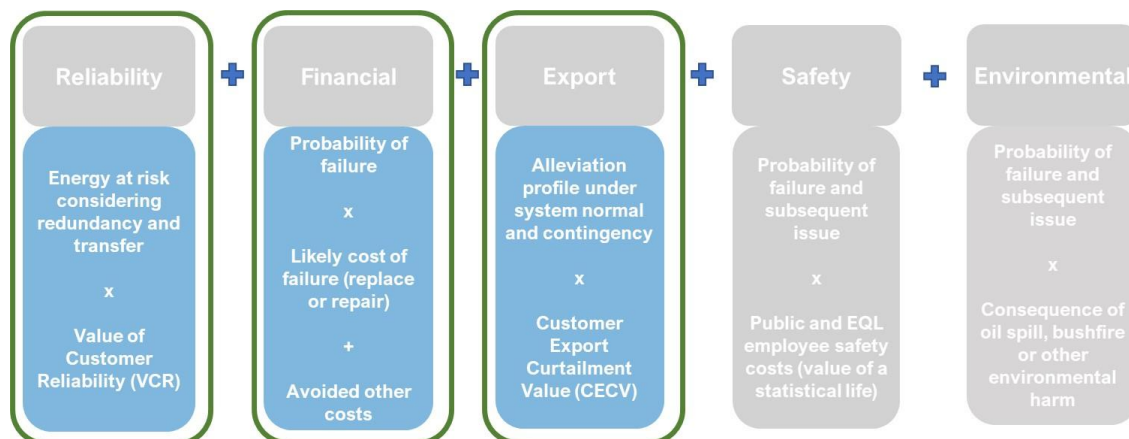


Figure 27 – Value Streams for Investment

3.2.3. Counterfactual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost and customer export curtailment, associated with equipment failure and unplanned supply outages at BOHL, DAGL, BLRI or on one of the 11kV distribution feeders supplying the Bohle Plains area.

In calculating the value streams the following assumptions are used:

- **Forced Outage Rate Transformers** – The transformer outage rates are predicted using a Weibull distribution with a Shape Parameter (β) of 3.6 and a Characteristic Life (η) of 79 for 66/11kV transformers. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure in the first years of a transformers life.
- **Forced Outage Rate Cables** – 11kV feeder cable outage rates are predicted using an average outage rate of 0.75 outages per 100km / year.
- **Restoration Transformers** – it has been estimated that the average rectification time would be 48 hours for a 66/11kV transformer outage. This considers repair / replacement time in the event of a permanent fault on the transformer.
- **Restoration Cables** – it has been estimated that the average rectification time would be 24 hours for a 11kV cable fault. This considers time to locate, excavate and repair / replace the cable.
- **Transfers** – for this assessment it has been assumed that 4MVA of manual load transfer capacity is available to BOHL, DAGL and BLRI via 11kV feeder ties from neighbouring substations. For 11kV distribution feeder outages on BO5, BO10, DG7 and DG10, the assessment assumes 4 into 3 capacity is available on these four feeders and that 1MVA of load can also be shifted to other neighbouring feeders.
- **Generation Support** – for this assessment it has been assumed that 1MVA of generation could be deployed to supply load in the Bohle Plains area within 8hours.
- **VCR Rate** – a VCR rate of \$34.68 / kWh has been used for the 11kV load supplied from BOHL, a VCR rate of \$35.26 / kWh has been used for the 11kV load supplied from DAGL

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

and a VCR rate of \$35.34 / kWh has been used for the 11kV load supplied from BLRI. The weighting applied to each customer type is shown in Table 9.

- **CECV** – determined using the values published in the customer export curtailment value (CECV) methodology on the AER website⁶.
- **Emergency replacement Cost:** On failure of assets the plant will be replaced like-for-like with an additional 30% cost in comparison to the planned project.
- **Risk timeframe** – the risks have been quantified over a 60-year period, starting from 2030 to align with the investment year of Option A (see below).

Figure 28 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2030 to 2090.

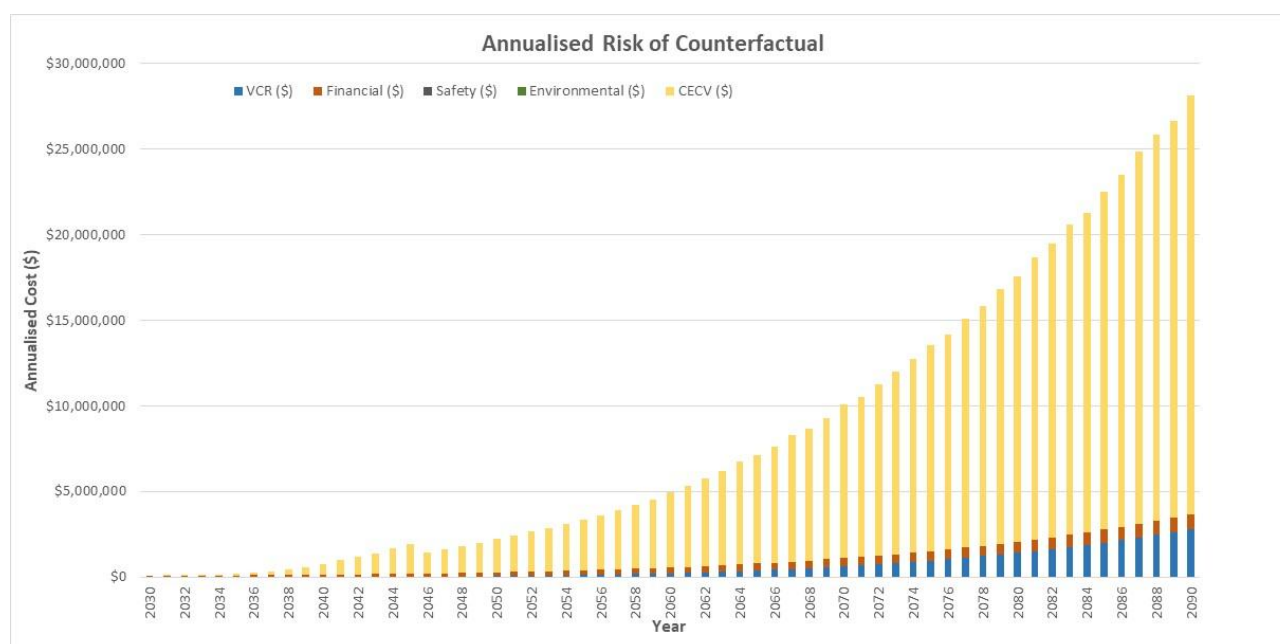


Figure 28: Annualised Risk of Counterfactual

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.

The VCR calculated for this analysis for the customers supplied from BOHL, DAGL and BLRI is shown in Table 9 based on the VCR values for different customer types as published by the AER.

⁶ <https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology>

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

Substation	Sector	Annual Consumption (kWh)	\$/kWh (2024)
BOHL	Residential (Climate Zone 1)	36,600,683	\$35.69
	Commercial*	42,789,529	\$34.39
	Industrial*	20,966,768	\$33.49
	Agriculture*	-	\$22.25
	Average VCR		\$34.68
DAGL	Residential (Climate Zone 1)	66,134,682	\$35.69
	Commercial*	29,703,442	\$34.39
	Industrial*	1,649,117	\$33.49
	Agriculture*	10,062	\$22.25
	Average VCR		\$35.26
BLRI	Residential (Climate Zone 1)	74,844,641	\$35.69
	Commercial*	14,491,174	\$34.39
	Industrial*	6,622,975	\$33.49
	Agriculture*	23,484	\$22.25
	Average VCR		\$35.34

Table 9: 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. 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.

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.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at BOHL, DAGL and BLRI 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.

3.3.2. 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.

3.3.3. 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 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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

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

4.1.1. 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 compliant with applicable regulatory instruments, including its Safety Net requirements.

This option involves 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.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

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.

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

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

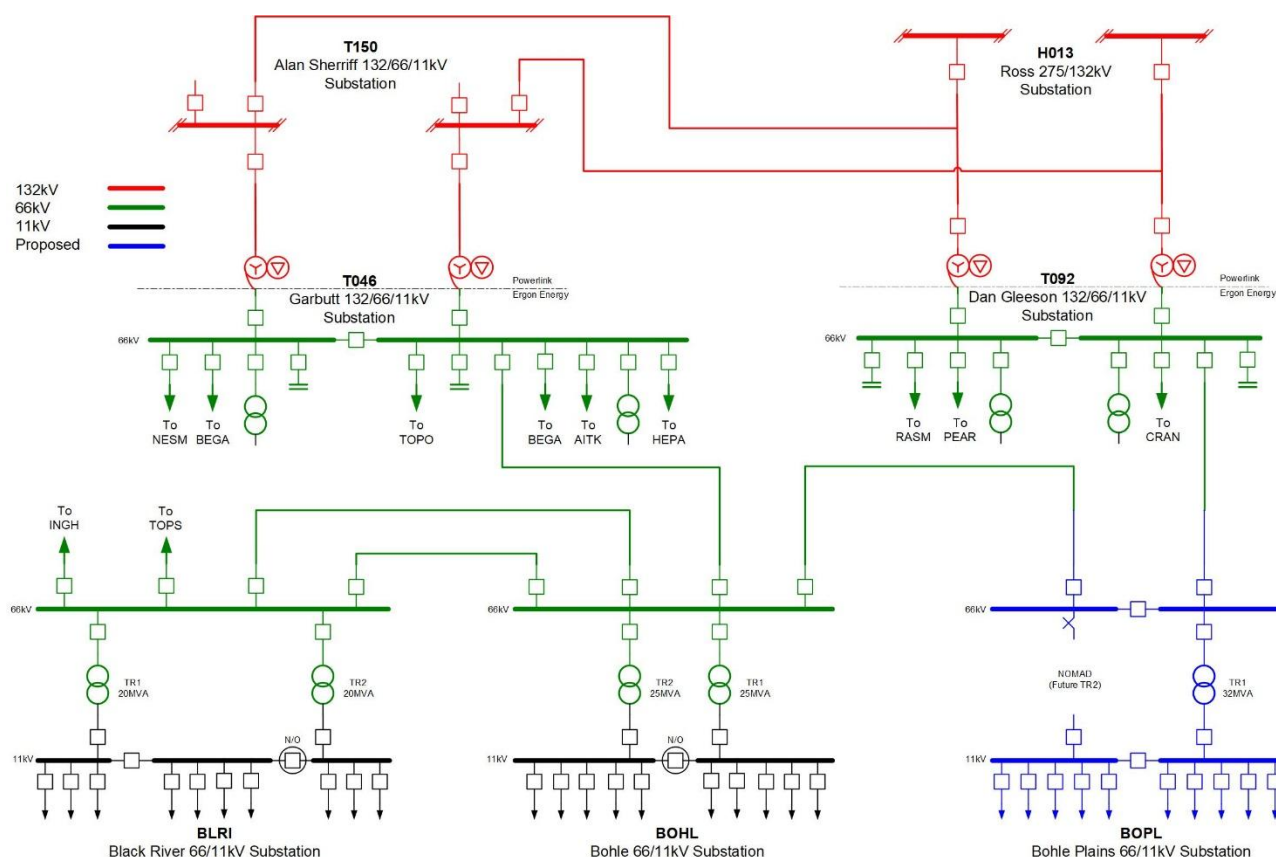


Figure 29: Option A proposed network arrangement (schematic view)

4.1.2. 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 compliant with applicable regulatory instruments, including its Safety Net requirements.

This option involves 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.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Ergon Energy does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

A schematic diagram with the proposed network arrangement for Option B is shown in Figure 30.

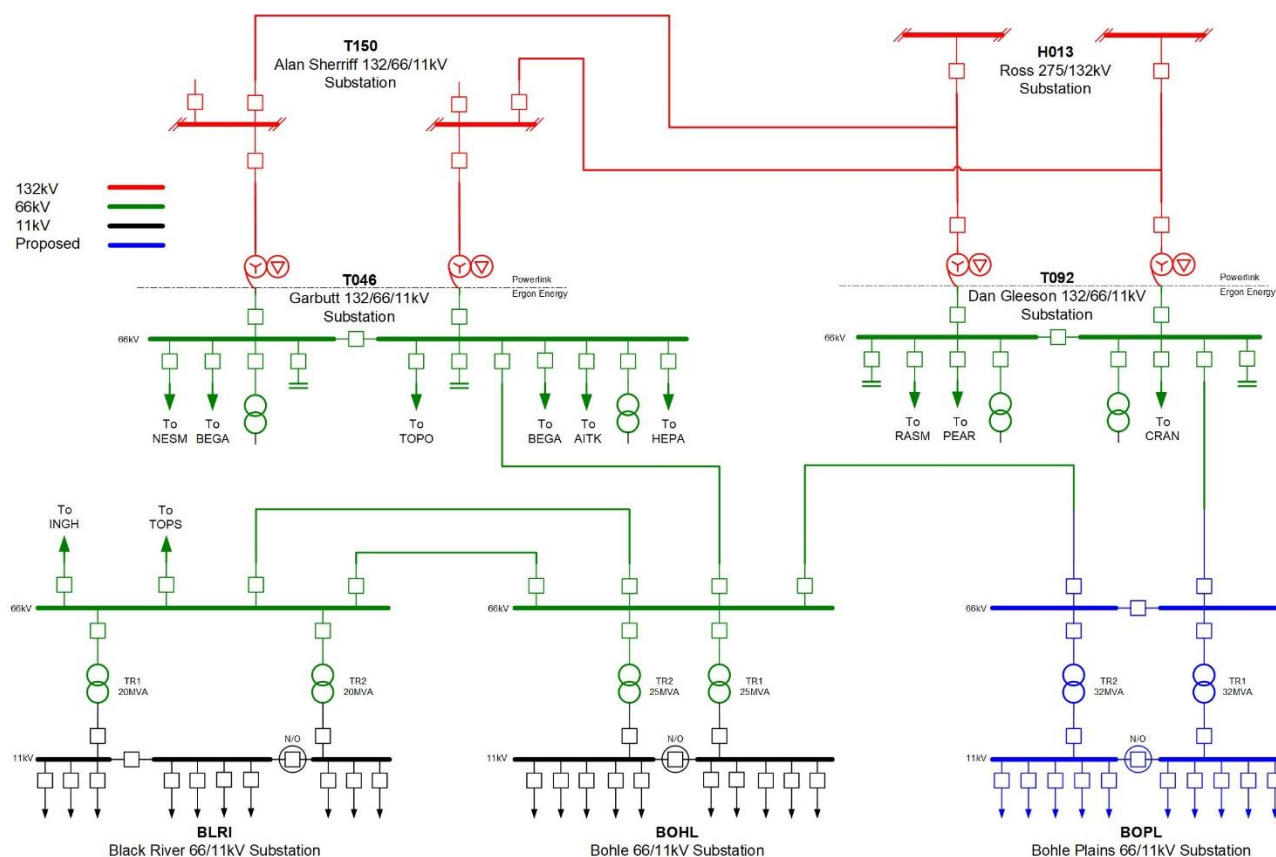


Figure 30: Option B proposed network arrangement (schematic view)

4.1.3. 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 compliant with applicable regulatory instruments, including its Safety Net requirements.

This option involves 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.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Ergon Energy does not anticipate any community stakeholder concerns, should

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

any be identified, these would be addressed as part of the Ergon Energy Community Engagement Framework which is integrated into the project workflow.

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 of the proposed network arrangement for Option C is shown in Figure 31.

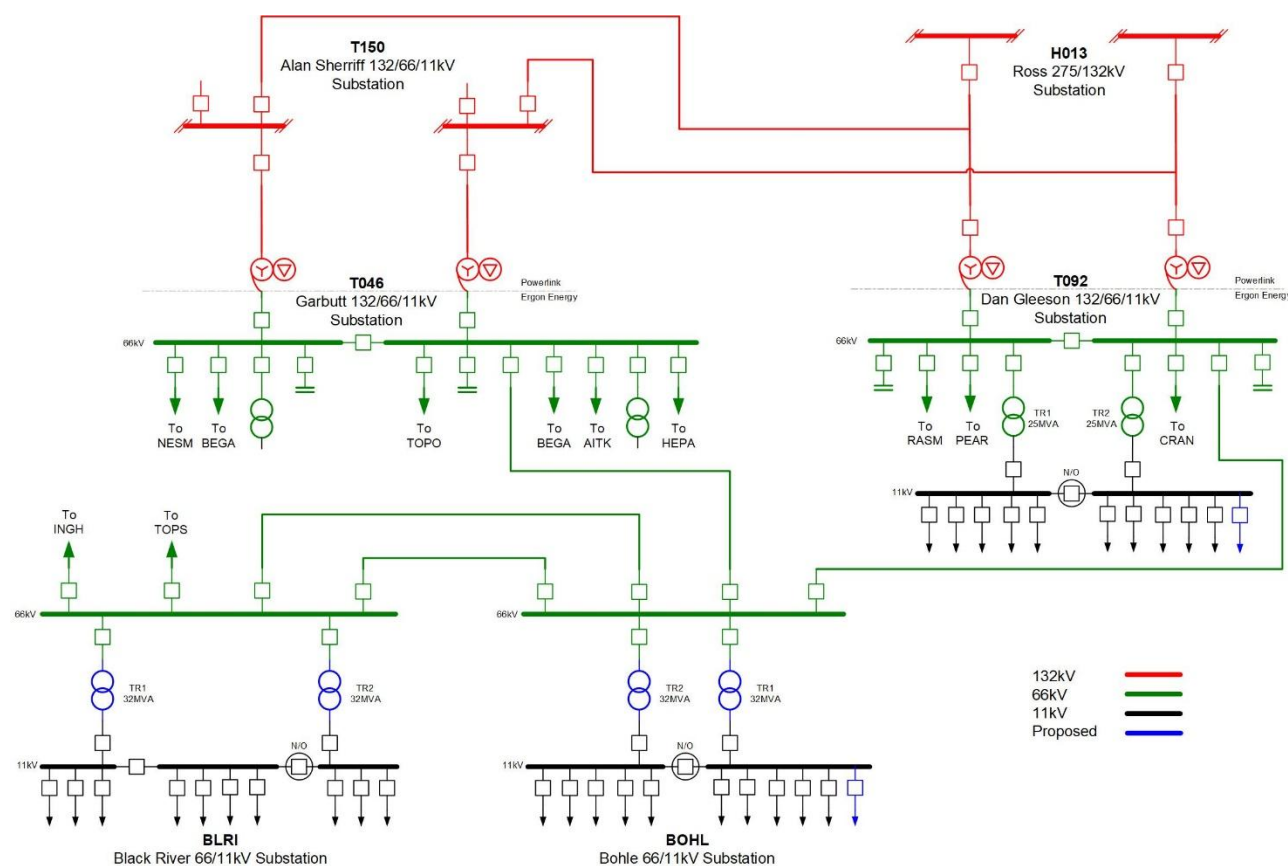


Figure 31: Option C proposed network arrangement (schematic view)

4.2. Assessment of SAPS and Non-Network Solutions

Ergon Energy has considered Standalone Power Systems (SAPS) and demand management solutions. Each of these are considered below.

4.2.1. 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 area could not be supported by a network that is not part of the interconnected national electricity system. Therefore, a SAPS option is not technically feasible.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

4.2.2. Demand Management (Demand Reduction)

Ergon Energy's Demand & Energy Management (DEM) team has assessed the potential non-network alternative (NNA) options required to address the identified need.

Credible options must be technically and commercially viable and must be able to be implemented in sufficient time to satisfy the identified risk to the public and/or the network due to the identified constraints.

The DEM team has completed a review of the Bohle Plains customer base and considered the suitability of 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 2079kVA⁷ is available.

DAGL has 6343 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3805kVA⁸ is available.

BLRI has 6641 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 3984kVA⁹ 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 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.

4.2.3. 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.

⁷ Hot water diversified demand saving estimated at 0.6kVA per system

⁸ Hot water diversified demand saving estimated at 0.6kVA per system

⁹ Hot water diversified demand saving estimated at 0.6kVA per system

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

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 has been assessed as technically not viable as there is no known existing LSG or proposed LSG that could address the identified network requirement.

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.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

4.2.4. SAPS and Non-Network Solution Summary

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

4.3. Preferred Option

Ergon Energy's preferred 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 by establishing a new zone substation at Bohle Plains ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

5. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO THE DRAFT PROJECT ASSESSMENT REPORT

On 7 March 2025, Ergon Energy published the Draft Project Assessment Report providing details on the identified need in the Bohle Plains network area. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the identified need.

In response to the Draft Project Assessment Report, Ergon Energy received no submissions by the closing date of 24 April 2025.

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 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 following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

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

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 \$34.68/kWh for the BOHL 11kV load, \$35.26/kWh for the DAGL 11kV load and \$35.34 for the BLRI 11kV load, which has been derived from the AER 2024 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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

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 Bohle Plains 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 load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Australia's greenhouse gas emissions
- Option value
- Costs Associated with Social Licence Activities

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 Bohle Plains 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 are not expected to affect the timing of other distribution investments for unrelated identified needs.

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

The credible options included in this RIT-D assessment are not expected to have an impact on the load transfer capacity or the capacity of embedded generators to take up load between the zone substations in the Bohle Plains area.

6.2.5. Changes in Electrical Energy Losses

Ergon Energy does not anticipate that any of the credible options included in the RIT -D assessment will lead to any significant change in electrical energy losses.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

6.2.6. Changes in Australia's Greenhouse Gas Emissions

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in greenhouse gas emissions.

6.2.7. 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 change¹⁰.

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.

6.2.8. Costs Associated with Social Licence Activities

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will involve costs associated with social licence activities.

¹⁰ AER "Regulatory Investment Test for Distribution Application Guidelines", Section A8.
Available at: <https://www.aer.gov.au/documents/aer-regulatory-investment-test-distribution-clean-21-november-2024>

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The RIT-D 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 NEM.

Accordingly, a base case NPV comparison of each credible option 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.

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model.

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.

Table 10 outlines the major sensitivities analysed within the Monte-Carlo analysis which was undertaken to assess the sensitivity to a change in parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
WACC	3.5%	2.5%	4.5%
Project Costs	Standard estimates	-40%	+40%
Project Costs	Preferred option estimates	-40%	+40%
Opex Costs	Calculated Opex	-10%	+10%

Table 10: 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.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

7.4. Net Present Value (NPV) Results

An overview of the base case NPV results are provided in Table 11.

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Establish Bohle Plains Zone Substation with a single 66/11kV transformer	1	\$4,650,000	-\$17,137,000	-\$6,608,000	\$28,394,000
B	Establish Bohle Plains Zone Substation with two 66/11kV transformers	2	\$4,032,000	-\$17,546,000	-\$6,700,000	\$28,278,000
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	3	\$1,413,000	-\$19,887,000	-\$7,527,000	\$28,827,000

Table 11: 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 12 provides the results of the WACC sensitivity analysis.

Option Number	Option Name	Rank	Net NPV (2.5% WACC)	Net NPV (4.5% WACC)
A	Establish Bohle Plains Zone Substation with a single 66/11kV transformer	1	\$15,379,000	-\$1,784,000
B	Establish Bohle Plains Zone Substation with two 66/11kV transformers	2	\$14,871,000	-\$2,496,000
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	3	\$11,447,000	-\$4,392,000

Table 12: Scenario Analysis – WACC sensitivity

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations of all the variables. Table 13 shows the average NPV cost of all the simulations.

Addressing increased customer demand in the Bohle Plains Area

Final Project Assessment Report

Option Number	Option Name	Average NPV	Maximum NPV	Minimum NPV
A	Establish Bohle Plains Zone Substation with a single 66/11kV transformer	\$4,697,000	\$9,659,000	-\$149,000
B	Establish Bohle Plains Zone Substation with two 66/11kV transformers	\$4,064,000	\$9,832,000	-\$1,035,000
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	\$1,479,000	\$6,839,000	-\$2,838,000

Table 13: Monte Carlo Analysis for Base Case Forecast

Option A also has the lowest average cost and is the most economical in 58.9% of cases in the Monte-Carlo simulations.

Based on the detailed economic assessment, Option A is considered to provide the optimum solution to address the forecast limitations and is therefore the preferred option.

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

8. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the preferred option to address the identified need.

8.1. Preferred Option

Ergon Energy's preferred 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.

Upon completion of these works the identified need would be addressed by establishing a new zone substation at Bohle Plains ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. This option will address the identified need, is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

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.

8.2. Satisfaction of RIT-D

The preferred option satisfies the RIT-D and maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

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

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

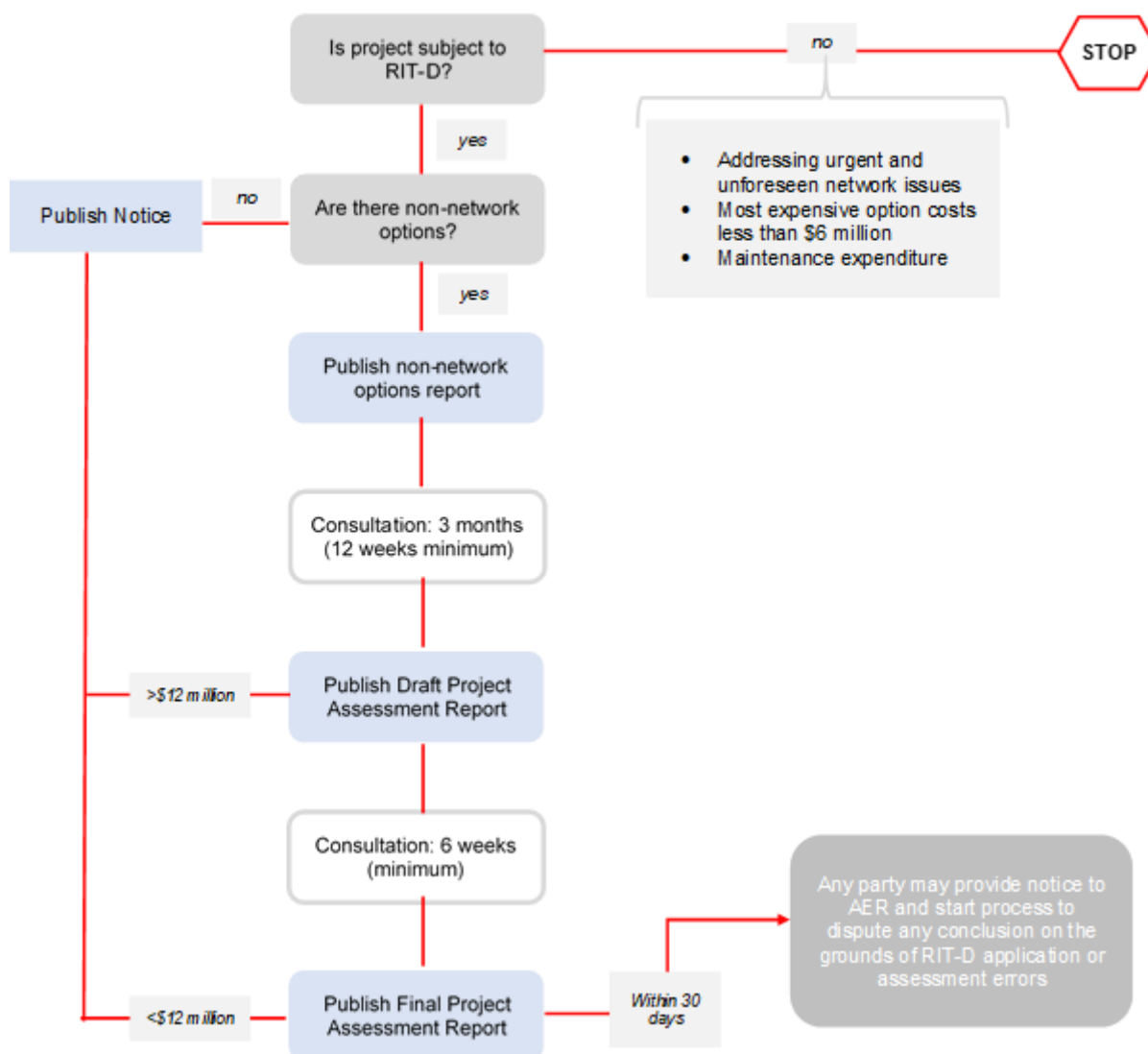
9. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(r) 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 DPAR;	5
(4) a description of each credible option assessed	4
(5) where a <i>Distribution Network Service Provider</i> 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	4 & 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
(10) the identification of the proposed preferred option	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: <ul style="list-style-type: none"> (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) 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 	8.1 & 8.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.4

Addressing increased customer demand in the Bohle Plains Area Final Project Assessment Report

APPENDIX A – THE RIT-D PROCESS



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