Regulatory Investment Test for Distribution (RIT-D)

Reliability Corrective Action
The Ingham Network Area

Draft Project Assessment Report

02/12/2025

Part of Energy Queensland

INTRODUCTION

Purpose

The National Electricity Rules (NER) require that, subject to certain exclusions, distribution network service providers who are looking to address an identified need, by investing in the network, must apply the regulatory investment test for distribution (RIT-D). This Draft Project Assessment Report (DPAR) has been prepared by Ergon Energy Corporation Limited (Ergon Energy) in accordance with the requirements of clause 5.17.4(j) of the NER and is published in accordance with 5.17.4(i) of the NER.

In preparing this DPAR, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has 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.

About Ergon Energy

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.

CONTENTS

1. ASSUMPTIONS AND TECHNICAL CHARACTERISTICS OF THE IDENTIFIED NEED

1.1. Location and Existing Supply Arrangement

Ingham is a rural township located in the Hinchinbrook Shire, Queensland and is approximately 100km north of Townsville. Ingham 66/11kV Zone Substation (INGHSS) is located on the southern edge of Ingham and is supplied from Powerlink's adjacent T157 Ingham South 132/66kV Substation (INSO). INGHSS supplies approximately 4,500 predominantly residential customers, although adjacent substation supplied via the 66kV from INGH supply large commercial customers. The substation supplies 53.8GWh annually, with roughly half of this energy consumed by residential customers. In recent years 2-3MVA which was previously supplied from Victoria Substation was transferred to INGH ZS, with a decision not to invest in rebuilding Victoria Substation.

INGH has three outgoing 66kV sub transmission feeders which supply various 66/11kV and 66/33kV substations, as well as six outgoing 11kV distribution feeders. Figure 1 shows the Ergon 66kV Network geographic layout, Figure 2 the existing network schematic, while Figure 3 and Figure 4 show the site geographic layout.

The substation is relied on for backup of the loads on the INGH-VICT-LUCI feeder for planned and unplanned outages.

In 2009 the area experienced a 1 in 13-year flood event which caused over 600mm of water to inundate the substation. As this area is prone to heavy rainfall the risk of substation flooding is very high (Figure 5), this is evidenced by further flooding events which occurred in February 2025 (Figure 6).

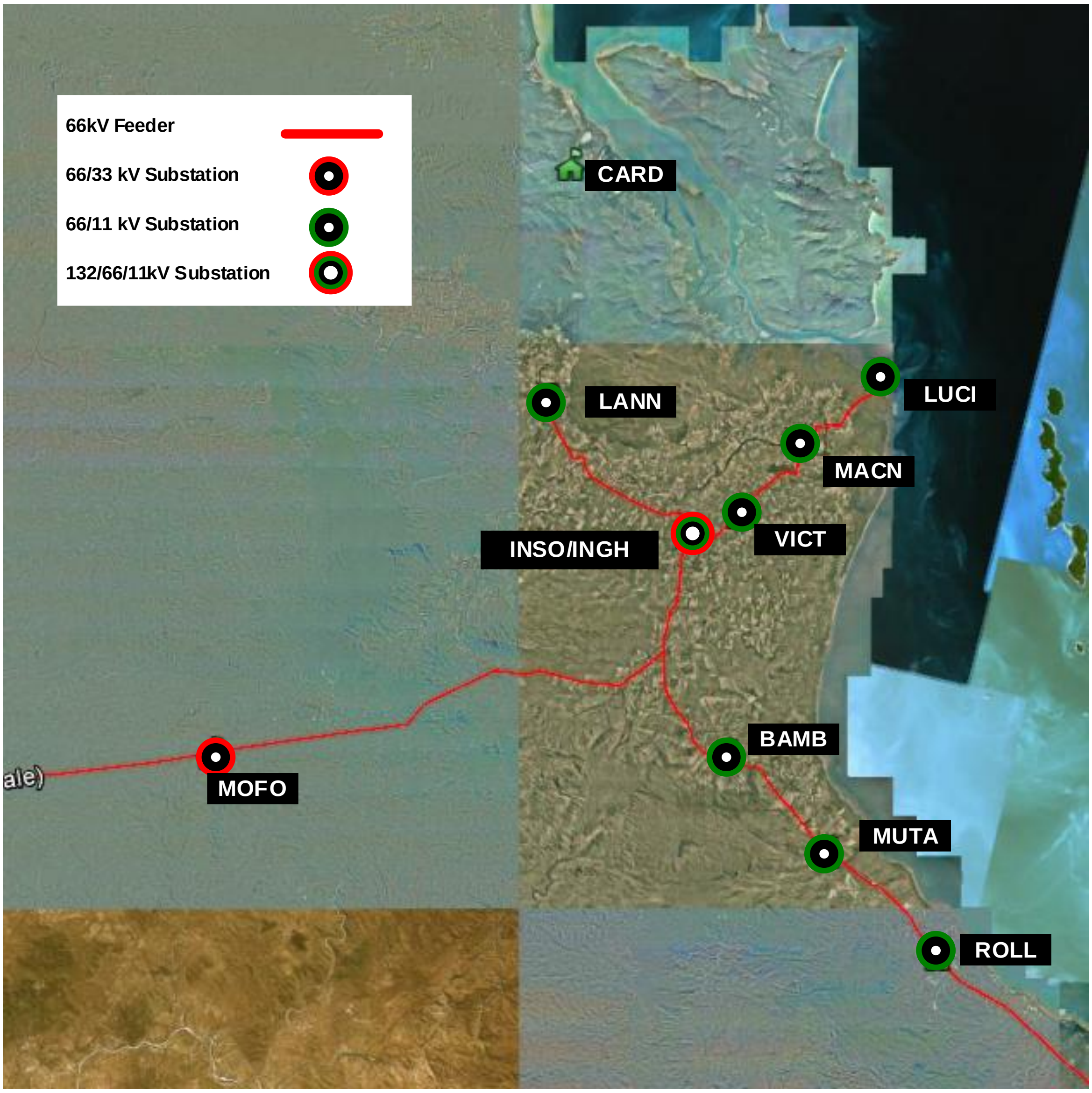


Figure 1: Existing network arrangement (Geographic view) of the Ingham Network. All network is owned by Ergon Energy unless otherwise noted

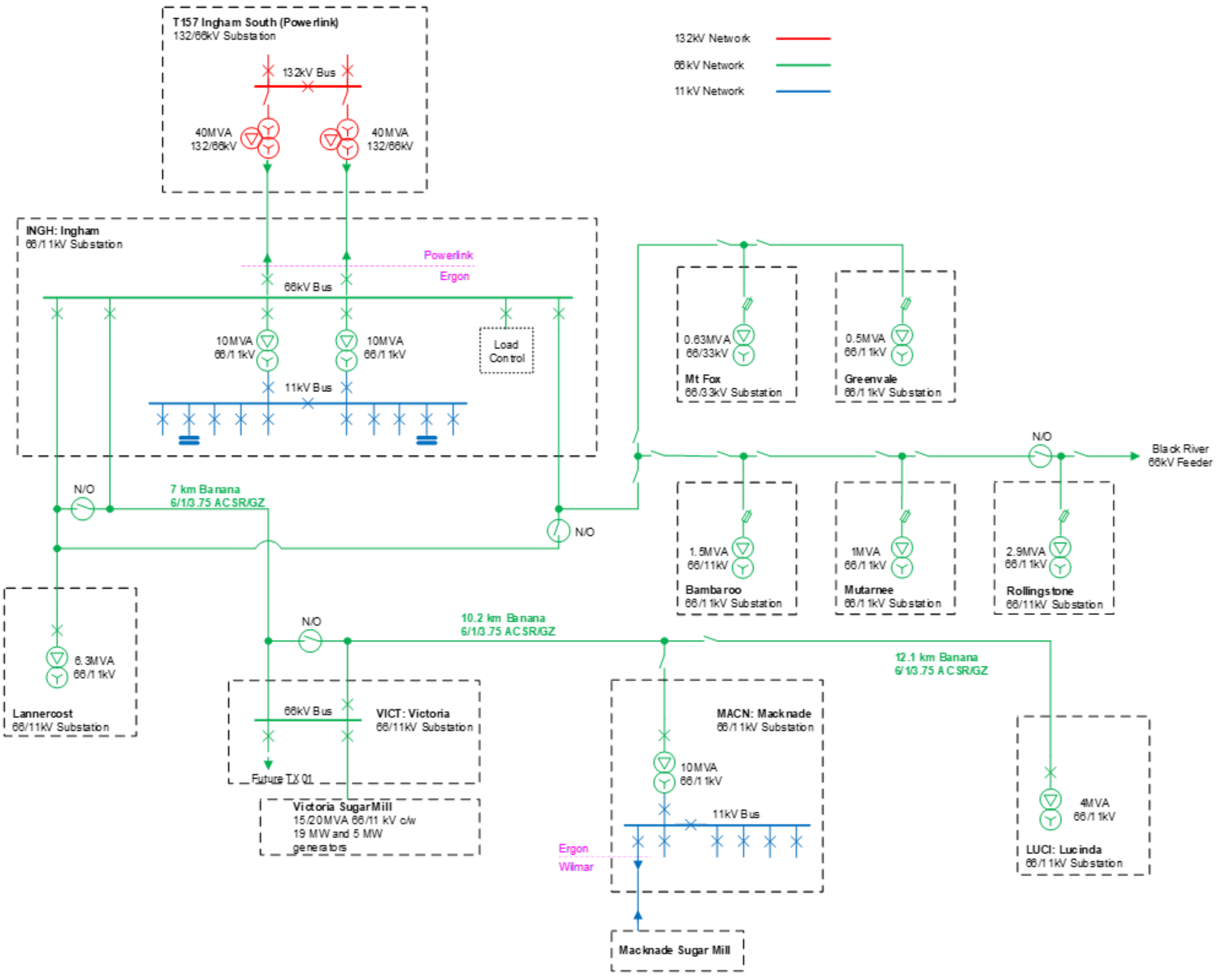


Figure 2: Existing network diagram of the Ingham Network

Figure 3: INGHSS (EE) and Ingham South (PLQ) substation geographic view

Figure 4: Ergon INGH 66/11kV Substation – Geographic Layout

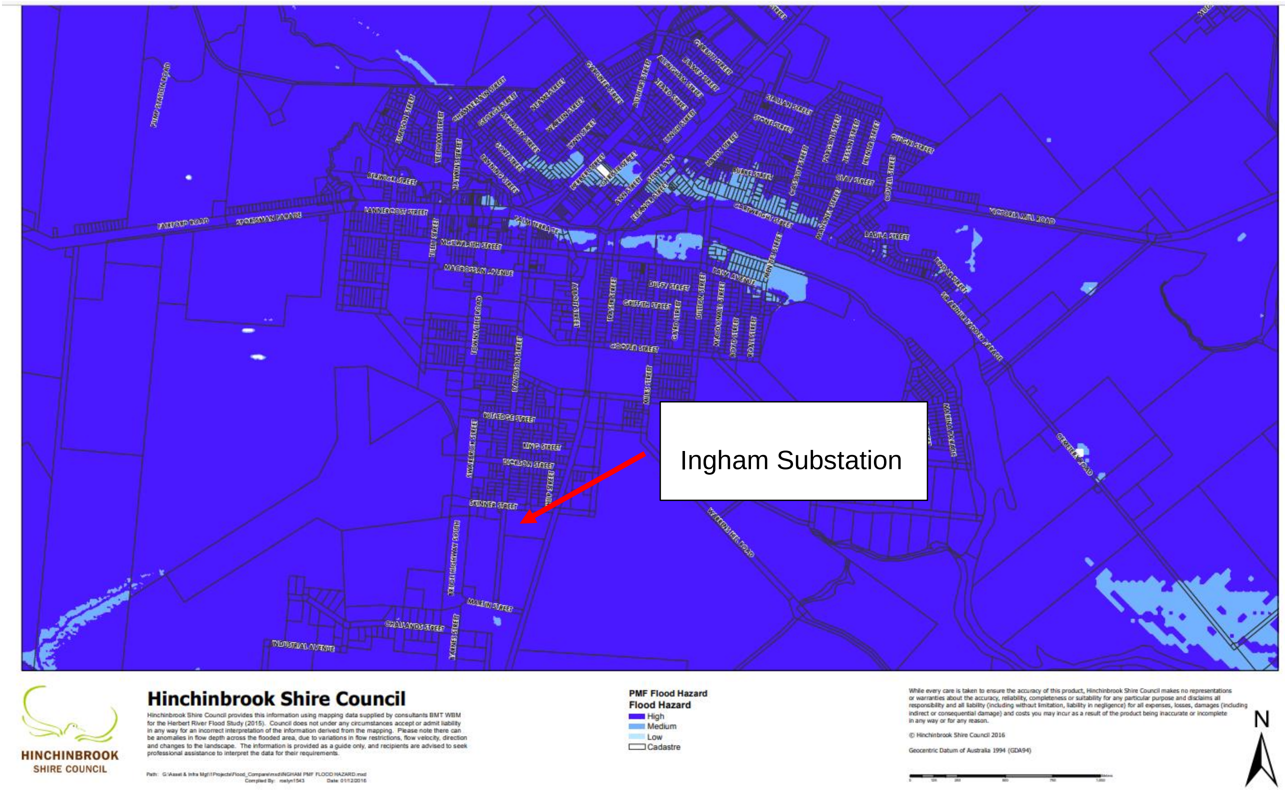


Figure 5: Ingham Flood Map

Figure 6: INGH 2025 Flood levels

1.2. Size of load reduction or additional supply

There is currently no load at risk at INGH with the energisation of existing assets under system normal. As shown in Figure 8 there is approximately 1MVA of load at risk under a transformer contingency. However, as these substation assts are end of life and located within flood plains for aged assets at INGH to be de-energized and meet the identified need, it is envisaged that a solution would need to be a stand-alone supply which does not require the operation of existing end of life asset. Therefore, the load reduction would need to be capable of supplying the entire peak load in both forward and reverse directions.

1.3. Contribution to power system security or reliability

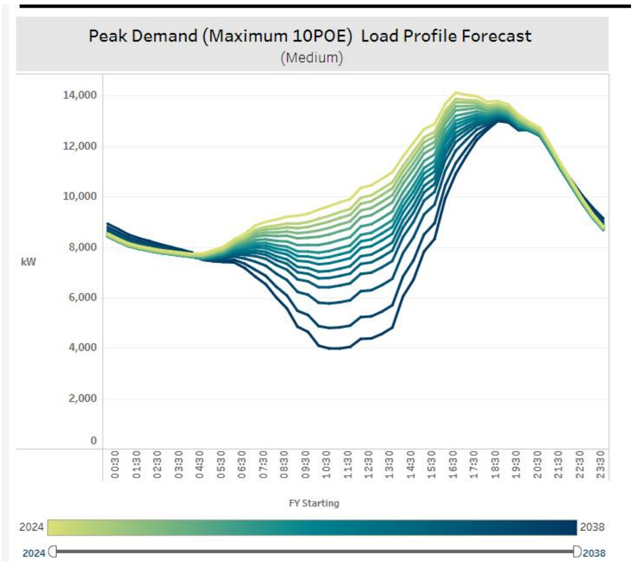
Ingham 66/11kV substation is the sole distribution substation supplying customers in the Ingham area. There are minimal 11kV load transfers available to neighbouring substation. Currently, without Ingham approximately 87% of existing customer supplied would be unsupplied. Any solution must comply with the security and reliability standards outlined in Ergon Energy's requirements under its Distribution Authority. The solution must be available to be called on for the full duration and load demand and under both forward and reverse power flow.

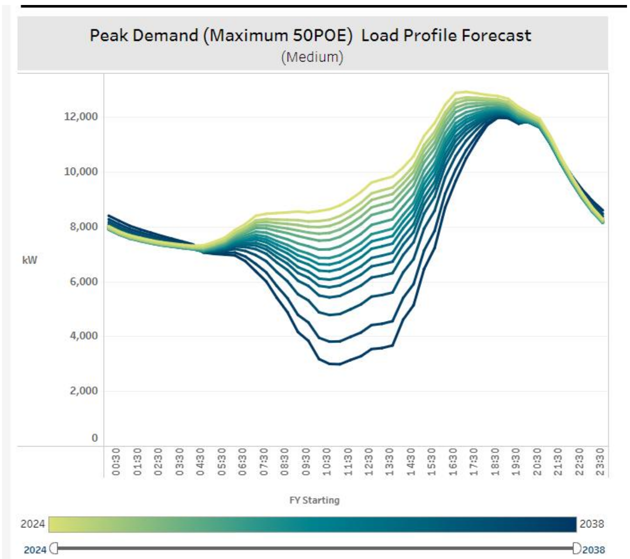
1.4. Contribution to power system fault levels

Powerlink's INSO substation is located adjacent to Ergon Energy's INGH substation. Any solution must consider the fault level contribution to the network and include any mitigation works that are required due to change in fault level. The maximum fault level on 11kV and 66kV network should not exceed 10.1kA/s and 13.3kA/s respectively, to ensure fault rating capability of assets are not exceeded.

1.5. Operating profile and Load Forecast

The base case 10POE and 50POE load forecast is shown in Figure 7 and Figure 8. It can be seen in these graphs that the load is expected to decrease both during the day and evening between 2025 and 2038. However, it should be noted that the 2022 predicted that the 10POE (50POE) load would increase from 14.77MVA (12.92MVA) in 2023 to 17.8MVA (15.56MVA) in 2034. This variation in the 10-year forecast within a two-year span shows the volatility of the electrical load anticipated to be connected in the area. This volatility should be considered when contemplating replacement of assets anticipated to be in service for the next 60 years, or alternate solutions which intend to be in operation beyond the forecast window.





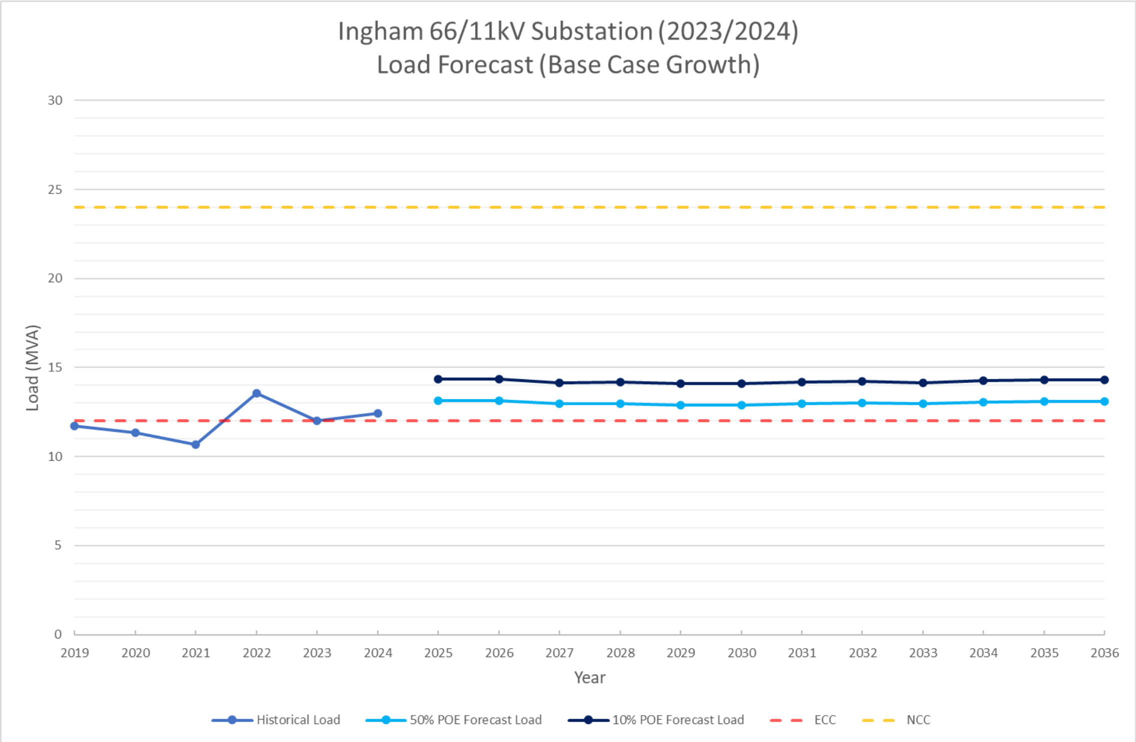


Figure 8: Ingham 66/11kV Historic Load and Load Forecast

The Emergency Cyclic Capacity provided in Figure 8 is 12MVA, based on the transformer rating. Historically these transformers have had their operational rating limited to as low as 10MVA due to poor condition and excessive moisture. As the assets age the potential to see operational restriction on these transformers increases, increasing the load at risk under a contingency event.

Figure 9 to Figure 11 show the actual load profiles between June 2023 and June 2024. These graphs show that Ingham substation is summer peaking with a maximum of 12.32MVA. The historic peak for the substation occurred in 2022 with a peak of 13.56MVA.

There are currently large customer loads being assessed for connection to INGH. This is anticipated to increase the loading at the substation by up to 2MVA.

Ingham substation also supplies substations at 66kV, these include Lucinda, Macknade, Mount Fox, Mutarnee, Lannercost, Victoria Mill, Greenvale and Bambaroo. In 2024 Ingham BSP (INSO) recorded loading of 20.07MVA, however a record peak of 22.47MVA was recorded in 2022. The 50POE is forecast to remain stable at 21MVA for the next 10 years.

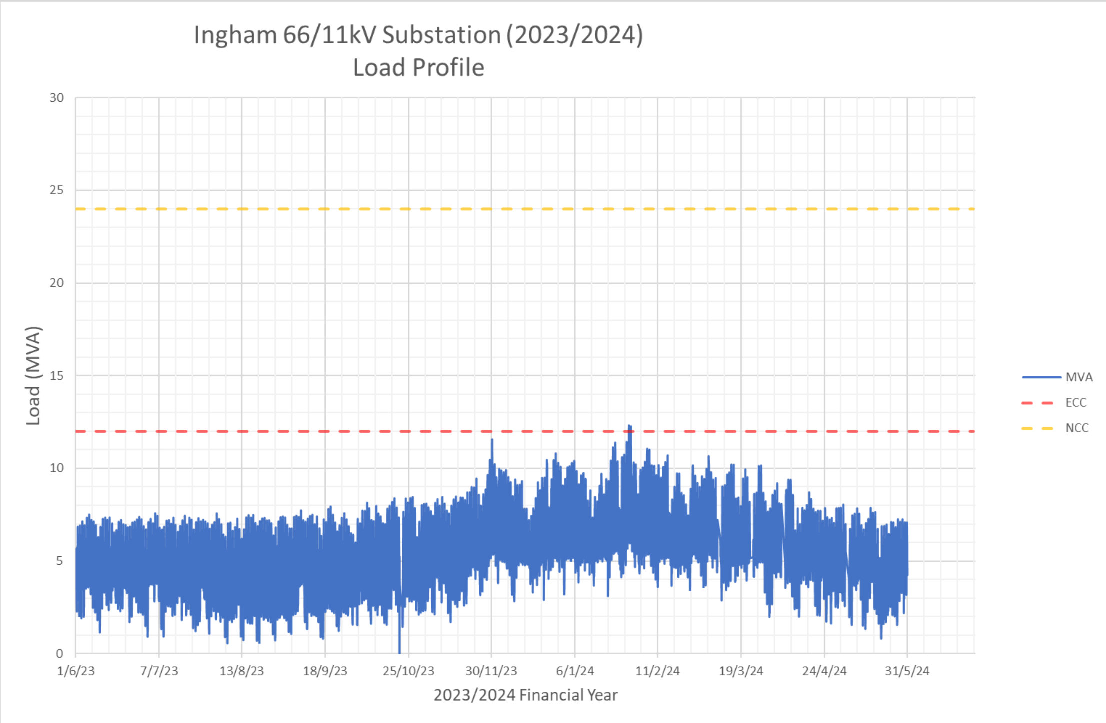


Figure 9: Ingham 66/11kV Historic Load Forecast

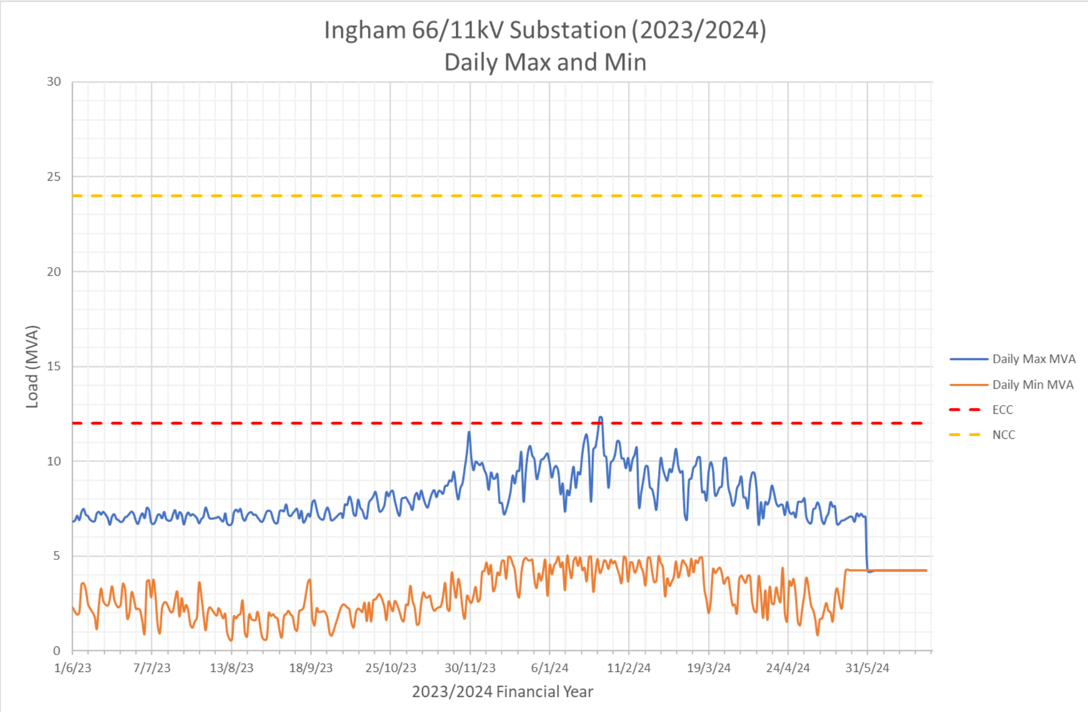


Figure 10: Ingham 66/11kV Daily Max and Min

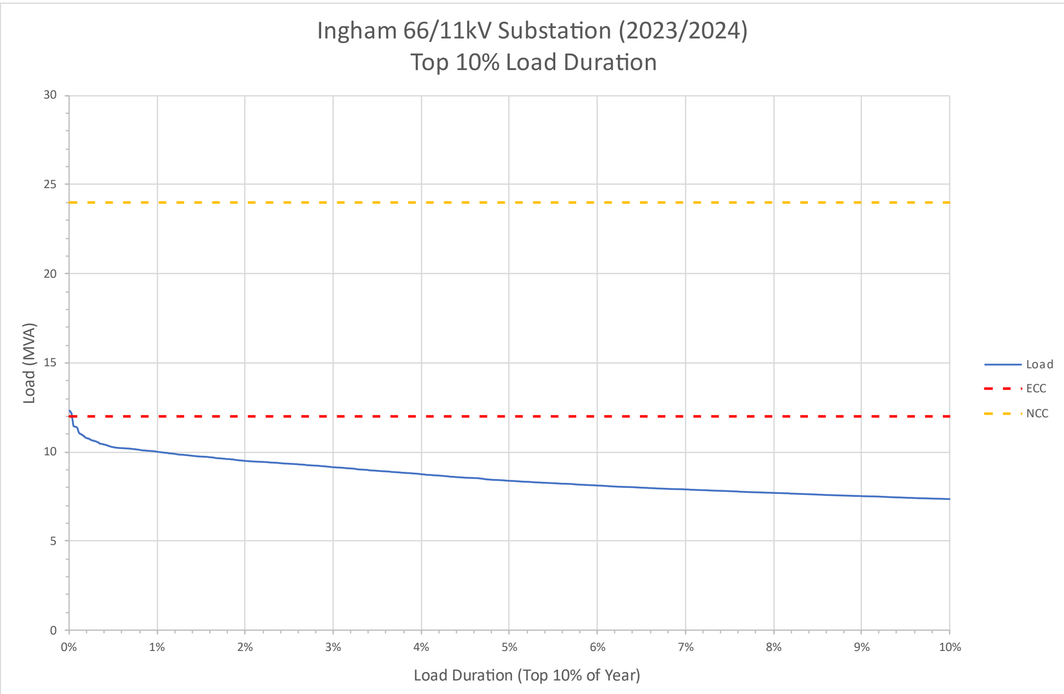


Figure 11: Ingham 66/11kV Load Duration Curve

2. IDENTIFIED NEED

INGHSS has assets which are operating beyond their forecast end of life and are located in flood plains, which increases the likelihood of asset failure. The condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from INGHSS. In particular, a long-term outage to the 66/11kV power transformers would cause a breach of Ergon Energy's regulatory obligations, reliability performance standards and technical requirements. These assets have been derated to nameplate capacity only in the past due to moisture ingress. Due to their location along with asset age the likelihood that they are limited to nameplate capacity increases, impacting on Ergon's regulatory obligations as highlighted below.

Ergon Energy has obligations to comply with the reliability performance standards specified in its Distribution Authority (DA), issued under the *Electricity Act 1994* (Qld) (the Act). If network investment did not occur, this would likely result in breaches of reliability performance obligations under Ergon Energy's DA, namely:

- Clause 7 - Guaranteed Service Levels (reliability of supply)
  - During a long-term, unplanned outage of the power transformers, customer load shedding would be required as insufficient load transfer capability exists to supply customer connected to INGHSS.
- Clause 8 - Distribution Network Planning
  - This clause states that the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. The INGHSS substation performs a critical role in maintaining voltages and power transfer capability in the network. Failing to maintain a reliable and secure 66/11kV network may be seen as a breach of this clause.
- Clause 9 - Minimum Service Standards
  - During a long-term, unplanned outage of the primary plant assets at INGH, customer load shedding may be required at. This would have a large, negative impact on system-wide SAIDI and SAIFI limits stipulated within the Minimum Service Standards.
- Clause 10 - Safety Net
  - A failure of the power transformer is deemed to be a credible N-1 contingency in terms of Safety Net planning requirements. However, the greater concern is of a double contingency of the power transformers due to poor asset condition and the likelihood of failure of the second transformer under an N-1 event. Further to this, flooding in the area can require both transformers to be pre-emptively de-energised due to their susceptibility to flooding. Under this scenario up to 80% of the INGHSS load would be unsupplied until the transformers could be repaired or re-energised. It is likely this would result in some customers being unsupplied beyond the 48-hour, full restoration target stipulated within the Schedule 4 Service Safety Net Targets.

Further to the above obligations, section 42(a)(i) of the Act states that distribution entities must comply with the reliability requirements, system standards and performance requirements specified within the National Electricity Rules (NER). Without investing in the network, the following system standards would likely be breached:

- Schedule 5.1a System Standards

  - S5.1a.3 System stability
- Schedule 5.1 Network Performance Requirements
  - S5.1.2 Network reliability
  - S5.1.2.1 Credible contingency events
  - S5.1.4 Magnitude of power frequency voltage
  - S5.1.5 Voltage fluctuations
  - S5.1.8 Stability

To ensure that Ergon Energy can continue to meet the service standards in its applicable regulatory instruments reliability corrective action is required by mid 2028, which is estimated to be the earliest date that a potential credible option could be implemented. If this does not occur, Ergon Energy estimates the probability of failure to comply with regulatory requirements is deemed to have reached unacceptably high levels.

3. POTENTIAL CREDIBLE OPTIONS

3.1. Credible Options Identified

Ergon Energy has considered all options that could reasonably be classified as a credible option without bias to energy source, technology, ownership and whether it is a network option, a non-network option or a SAPS option.

Ergon Energy has identified the following potential credible options that are commercially and technically feasible and can be implemented in an appropriate timeframe to address the identified need. All costs and benefits for each credible option have been measured against the counter factual.

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

3.1.1. Option A: Install 2 x 20MVA Transformers in Vacant Space

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by reducing safety risks associated with end of life assets, increase reliability by installing new assets above flood level, increase network capacity to meet future demand and comply with system standards and performance specified in the NER.

The estimated capital cost of this option would be $15.8m. The estimated operating costs of this option would be $76,245 The estimated commissioning date of this option would be June 2028.

The scope of works for this option includes:

- Replace 2 x 66/11kV Transformers with 20MVA 66/11kV Transformers
- Replace 3 x 66kV CVTs
- Replace 4 x 66kV CTs
- Replace 2 x station services transformers
- Replace 15 x 66kV Surge Arrestors

- Replace 10 x 11kV feeder relays and implement standard dual relay protection schemes on outgoing feeders
- Replace 1 x 11kV CBF relay and implement current standard bus protection scheme
- Replace 2 x 66kV DIST/ DIFF relay with DIFF relay on outgoing 66kV feeder
- Replace 1 x 66kV AFLC bay relay with standard dual relay
- Replace 4 x 66kV protection relays on 66kV feeders
- Replace existing 48V DC system with dual 48V DC system
- Replace Foxboro RTU with SEL RTA 3555 and CGI RTUs
- Replace all Foxboro RTUs with four CGI MD100m RTUs
- Implement IPAC/CB control on all replaced 11kV relays
- Implement IPAC/ CB control on all replaced 66kV feeder and AFLC relays
- Ensure transformers, CT marshalling boxes, AFLC CB are raised above flood levels

The estimated option timeline is:

- Detailed Design Complete – December 2026
- Construction Commence – February 2027
- Project Completion – June 2028

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option)
- other operating and maintenance costs during the assessment period; and
- costs of complying with relevant laws, regulations and administrative requirements.

Due to Option A’s scope of works being entirely contained within the existing Ingham/ Ingham South substation land parcel, as well as the expected reliability and safety 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 of this option.

3.1.2. Option B: Install 2 x 10MVA Transformers in 2028 and a 3rd Transformer in 2035

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by reducing safety risks associated with end of life assets, increase reliability by installing new assets above flood level, increase network capacity to meet future demand and comply with system standards and performance specified in the NER. This would be achieved in two stages, the first being completed by 2028 and the second completed by 2035.

The estimated capital cost of this option would be \$12.7m in stage 1 and \$7.0m in stage 2. The estimated operating costs of this option would be \$96,060.

The scope of works for Stage 1 of this option includes:

- Replace 2 x 66/11kV Transformers with 10MVA 66/11kV Transformers
- Replace 3 x 66kV CVTs
- Replace 4 x 66kV CTs
- Replace 2 x station services transformers
- Replace 15 x 66kV Surge Arrestors
- Replace 10 x 11kV feeder relays and implement standard dual relay protection schemes on outgoing feeders
- Replace 1 x 11kV CBF relay and implement current standard bus protection scheme
- Replace 2 x 66kV DIST/ DIFF relay with DIFF relay on outgoing 66kV feeder
- Replace 1 x 66kV AFLC bay relay with standard dual relay
- Replace 4 x 66kV protection relays on 66kV feeders
- Replace existing 48V DC system with dual 48V DC system
- Replace Foxboro RTU with SEL RTA 3555 and CGI RTUs
- Replace all Foxboro RTUs with four CGI MD100m RTUs
- Implement IPAC/CB control on all replaced 11kV relays
- Implement IPAC/ CB control on all replaced 66kV feeder and AFLC relays
- Ensure transformers, CT marshalling boxes, AFLC CB are raised above flood levels

The scope of works for Stage 2 of this option includes:

- Install 1 x 10MVA 66/11kV Transformer

The estimated option timeline is:

- Stage 1 - Detailed Design Complete – December 2026
- Stage 1 - Construction Commence – February 2027
- Stage 1 - Project Completion – June 2028
- Stage 2 – Project Completion – November 2035

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option)
- other operating and maintenance costs during the assessment period; and
- costs of complying with relevant laws, regulations and administrative requirements.

Due to Option B's scope of works being entirely contained within the existing Ingham/ Ingham South substation land parcel, as well as the expected reliability and safety 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 of this option.

4. QUANTIFICATION OF MARKET BENEFITS FOR EACH CREDIBLE OPTION

The following classes of market benefits have been considered in completing the RIT-D assessment:

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

4.1. Changes in Voluntary Load Curtailment

There are no customers on voluntary load curtailment agreements in the study area and therefore Ergon has determined that there will be no material change in this class of market benefits for any of the potential credible options.

4.2. Changes in Involuntary load shedding and Customer Interruptions

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon 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 counter factual, 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 kWh 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 kWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D. Customer export Curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option result 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 study area

4.3. Changes in Costs for Other Parties

Ergon Energy has determined that there will be no material change in costs incurred by other parties due to any of the potential credible options.

4.4. Differences in the Timing of Expenditure

The potential credible options included in this RIT-D assessment are not expected to affect the timing of other distribution investments for unrelated identified needs. Ergon Energy has determined that there will be no material change in this class of market benefit for any of the potential credible options.

4.5. Changes in load transfer capacity and the capacity of distribution connected units to take up load

The potential credible options included in this RIT-D assessment will not materially change the load transfer capability. Credible options do increase the load and hosting capacity for distribution connections. The market benefits gained from increased capacity or ability to connect further embedded generators is treated in the same way as changes in involuntary load shedding and customer interruptions.

4.6. Changes in Electrical Energy Losses

Ergon Energy anticipates that the credible options included in the RIT-D assessment will reduce electrical energy losses, however, the reduction is not significant enough to result in a material change in market benefit.

4.7. Changes in Australia's Greenhouse Gas Emissions

Ergon Energy has determined that the change in Australia's greenhouse gas emissions for any of the potential credible options do not result in a material change in market benefit.

4.8. Costs Associated with Social Licence Activities

Ergon Energy has determined that the costs associated with social licence activities for any of the potential credible options do not result in a material change in market benefit.

5. NPV ANALYSIS OF EACH CREDIBLE OPTION

This section outlines the methodology applied in assessing the market benefits and costs associated with each potential credible option.

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 National Electricity Market. Accordingly, a base case Net Present Value (NPV) comparison of the potential credible options has been undertaken. A sensitivity analysis was then conducted to establish the option that remained the lowest cost option in the scenarios considered.

5.1. Overview of Analysis Framework

All costs and benefits for each credible option have been measured against a ‘business as usual’ base case, known as the counter factual. Under the counter factual, Ergon Energy would not be compliant with its requirements under applicable regulatory instruments. The RIT-D analysis has been undertaken over a 60-year period, from 2028 to 2088 to account for assets with 60 year expected life. Ergon Energy has adopted a real, pre-tax discount rate of 3.69% as the central assumption for the NPV analysis, this aligns with the latest AER Final Decision for a Distribution Network Service Provider’s (DNSP’s) regulated weighted average cost of capital (WACC) at the time of preparing this DPAR. To test the results against variations in the discount rate, an upper value sensitivity of 4.69% and a lower value sensitivity of 2.69% have been adopted for this RIT-D.

5.2. Estimating the Costs of each Potential Credible Option

Ergon Energy uses a combination of comparative and standard cost estimating methodologies, underpinned by a bottom-up approach as the basis for the estimation process of individual projects, which provides the platform for the development of forecast capital and operating expenditure. Standard cost estimation forms the basis of typical larger, lower volume high complexity type network projects. With this approach, the most common network configurations associated with transmission, sub-transmission and distribution project types or components are catered for, incorporating the experience and knowledge of agreed engineered standard ways of construction of network components. These cover a wide range of activities and are adjusted on application to cater for site specific identified requirements through a bottom-up quantification of project scope and application. Comparative costing is used where a statistically significant historical sample size exists, whereby actual project or program costs are reconciled and assessed. This approach is used in determining the operating costs. Ergon Energy has estimated the capital and operating costs of each potential credible option which is inclusive of the following components:

- All material costs.
- All labour costs incurred in delivery of the project (e.g. planning, design, construction, commissioning, network operations, and project management).
- All contractor costs incurred.
- Ancillary cost such as location allowances, environmental offsets.

5.3. Sensitivity Analysis

A sensitivity analysis was conducted to establish the option that remained the lowest cost option in the scenarios considered. Table 1 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.

Table 1: Economic Parameters and Sensitivity Analysis Factors

Parameter	Mode Value	Lower Bound	Upper Bound
Discount Rate	3.69%	2.69%	4.69%
Project Costs	Standard Estimate	-40%	+40%
Opex Costs	Comparative Estimate	-10%	+10%

5.4. Considered Scenarios

Only the base case load forecast scenario has been considered. The variation between the low and high forecast did not have a material impact on the timing or credible options for meeting the identified need.

5.5. Ranking of Credible Options

The table below summarises the costs of the potential credible options relative to the counter factual in present value terms under the different scenarios. The cost is the estimated capital costs of each option to address the identified need.

Table 2: NPV Results Table (3.69% WACC)

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Install 2 x 20MVA Transformers in 2028	1	**-2,209**	-14,103	1,687	10,206
B	Install 2 x 10MVA Transformers in 2028 + 3rd Transformer in 2035	2	**-5,975**	-16,830	851	10,004

Table 3: NPV Results Table (2.69% WACC)

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Install 2 x 20MVA Transformers in 2028	1	**1,321**	-14,447	2,111	13,657
B	Install 2 x 10MVA Transformers in 2028 + 3rd Transformer in 2035	2	**-3,043**	-17,485	1,034	13,408

Table 4: NPV Results Table (4.69% WACC)

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Install 2 x 20MVA Transformers in 2028	1	**-4,532**	-13,743	1,379	7,831
B	Install 2 x 10MVA Transformers in 2028 + 3rd Transformer in 2035	2	**-7,784**	-16,163	717	7,662

Table 5: Monte Carlo Analysis

Option	Option Name	Rank	Average NPV	Maximum NPV	Minimum NPV	Best NPV	Worst NPV
A	Install 2 x 20MVA Transformers in 2028	1	**-2,180**	784	-4,896	97.4%	2.6%
B	Install 2 x 10MVA Transformers in 2028 + 3rd Transformer in 2035	2	**-5,903**	-2,943	-8,311	2.6%	97.4%

6. PREFERRED OPTION

Option A has been identified as the preferred option and it satisfies the regulatory investment test for distribution. This option maximises the present value of the net economic benefit.

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

7. SOCIAL LICENCE AND COMMUNITY ENGAGEMENT

7.1. Social Licence

Ergon Energy has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need.

7.2. Community Engagement

As the scope of works for this project will not extend into new areas of the community and will be entirely contained within the existing site owned by Ergon Energy, it is not expected to cause any disruption to the community at large. As a result, we have not identified any community stakeholders who might reasonably be expected to be affected by the development of this project. 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.

8. REQUEST FOR SUBMISSIONS

Ergon Energy engages with customers and demand management providers to develop and implement demand side, non-network and SAPS solutions in accordance with our Industry Engagement Document.[1]

Ergon Energy invites written submissions on the matters set out in this DPAR, including the proposed preferred option, from registered participants, AEMO, interested parties, non-network providers and persons registered on Ergon Energy's industry engagement register.

Ergon Energy will not be legally bound in any way or otherwise obligated to any person who may receive this DPAR or to any person who may provide a submission. At no time will Ergon Energy be liable for any costs incurred by a proponent in the assessment of this DPAR, 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 DPAR.

For any queries in relation to this DPAR, please contact:

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

Submissions in writing are due by 4pm on the 20th January 2026 and should be lodged to demandmanagement@ergon.com.au

[1] Available at: https://www.ergon.com.au/network/manage-your-energy/managing-electricity-demand/

9. COMPLIANCE STATEMENT

This DPAR complies with the requirements of clause 5.17.4(j) of the NER as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	1 and 2
(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;	1 and 2
(3) if applicable, a summary of, and commentary on, the submissions received on the Options Screening Report;	N/A
(4) a description of each credible option assessed	3
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	4
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	3
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	4
(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	4
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	5
(10) the identification of the proposed preferred option	6
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (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	3 and 6
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	8
5.17.4(k) request for submissions on the matters set out in DPAR	8