Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Atherton Network Area

Draft Project Assessment Report

30 January 2025

Part of Energy Queensland

EXECUTIVE SUMMARY

About Ergon Energy

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

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

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

Identified Need

Atherton is a rural township located in the tablelands region of Far North Queensland, 80km south-west of Cairns and is known for its agriculture. Atherton 66/22kV zone substation (ATHE) was constructed in 1957 and supplies approximately 12,392 customers with over 85% of the total number of customers being residential. However, of the 140GWh of energy supplied annually, the usage is dominated by Commercial, Industrial and Agriculture (57%) with only 43% being consumed by residential customers. The energy usage helps to understand how vital the continued operation of ATHE is to the industry, agriculture and livelihood of those living in the tablelands region.

Condition Based Risk Management (CBRM) analysis indicates that the following items of plant have reached retirement:

- 1 x 66kV Circuit Breaker
- 3 x 66kV Current Transformers
- 12 x 66kV Voltage Transformers
- 14 x 66kV isolators
- 1 x local services Transformer
- 25 x Protection Relays

The ASEA >HLR 84/2001 A2U Circuit Breaker which was manufactured in 1974 has a history of high contact resistance and repairing of the spring charge chain. There is a lack of spares available for the ASEA current transformers, additionally the porcelain housings of these CTs are a known safety risk due to likelihood of explosive failure. Many of the 66kV CVTs are known to be problematic, where possible Ergon has installed CVT monitoring however it is recommended where substation projects are being completed for these problematic CVTs to be replaced sooner rather than later. Inspection of the isolators shows rust and algae evident on the surface of all the isolators. These isolators are greater than 60 years of age and are likely to have high probability of failure due to weathered and corroded contacts. This poses an issue for staff when operating these isolators as they can become stuck, however also poses a reliability risk to the network as they may not be able to be closed or have poor contact after being opened to perform maintenance within the substation.

The continued use of problematic plant and assets beyond end of life poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of catastrophic failure. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[1] to eliminate electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

The poor 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 ATHE. Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[2] issued under the Electricity Act 1994 (Qld).

Ergon Energy is seeking to invest in the network to undertake a reliability corrective action to continue to meet the service standards in its applicable regulatory instruments (National Electricity Rules[3], *Electricity Act 1994* (Qld)[4], *Electrical Safety Act 2002* (Qld)).

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 Atherton supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

A single potentially feasible option has been investigated:

[1] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity
[2] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
Section 9 - Minimum Service Standards
Section 10 – Safety Net

[3] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements
[4] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

- **Option A:** 66kV Asset replacement

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

Ergon Energy's preferred option is Option A, to replace the 66kV AIS with 66kV GIS, replace 66kV CTs and VTs, replace local service transformer and replace end of life protection relays by 2027.

This DPAR seeks information from interested parties about possible alternate solutions to address the identified need.

Submissions in writing are due on the **18 March 2025** by 4pm and must be lodged to demandmanagement@ergon.com.au

For further information and inquiries please contact:

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

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1. INTRODUCTION

This Draft Project Assessment Report has been prepared by Ergon Energy in accordance with clause 5.17.4(i) of the NER and includes the required contents pursuant to clause 5.17.4(j) of the NER.

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

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

1.1. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Atherton 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.
- Is an invitation to registered participants and interested parties to make submissions.

1.2. Contact Details

Submissions in writing are due by 4pm on **18 March 2025** and should be lodged to demandmanagement@ergon.com.au.

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Atherton is a rural township located in the tablelands region of Far North Queensland, 80km south-west of Cairns and is known for its agriculture. Atherton 66/22kV zone substation (ATHE) was constructed in 1957 and supplies approximately 12,392 customers with over 85% of the total number of customers being residential. However, of the 140GWh of energy supplied annually, the usage is dominated by Commercial, Industrial and Agriculture (57%) with only 43% being consumed by residential customers. The energy usage helps to understand how vital the continued operation of ATHE is to the industry, agriculture and livelihood of those living in the tablelands region.

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

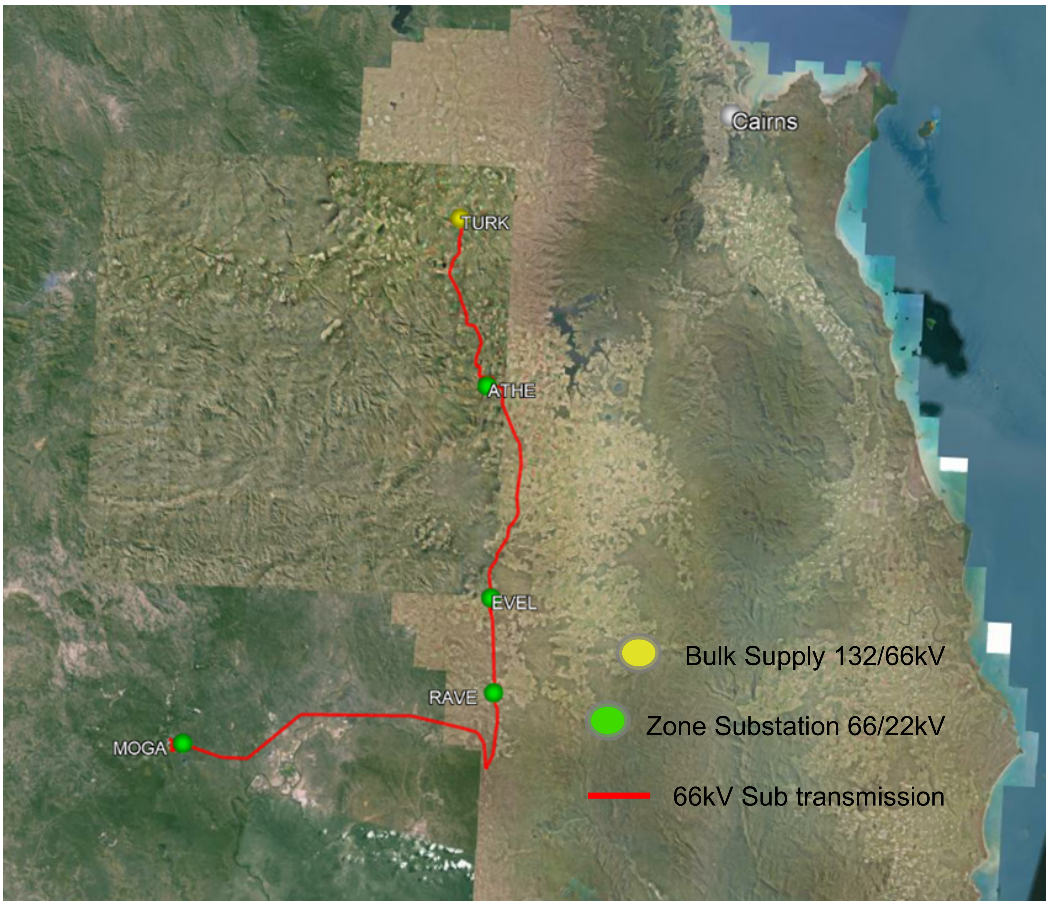


Figure 1: Geographic of the North Burnett area sub-transmission network

2.2. Existing Supply System

ATHE is supplied with two 66kV feeders (ATH No. 1 & ATHE No. 2) from T055 Tukinje 132/66kV bulk supply point (TURK). Figure 1 shows the geographic layout of the Tablelands area 66kV network.

Figure 2 gives a line diagram of ATHE and shows that there are two outgoing 66kV feeders which supply Evelyn 66/22kV substation (EVEL) and Mt Garnett 66/22kV substation (MOGA), and nine 22kV distribution feeders which supply Atherton and the surrounding area.

ATHE is equipped with two 24/30/40MVA 66/22kV transformers (T1 and T2), with both the 66kV and 22kV switchgear being outdoor AIS. There are seven 66kV CBs including a 66kV bus section breaker and fifteen 22kV CBs including a 22kV bus section breaker.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the general site layout of ATHE is illustrated in Figure 3.

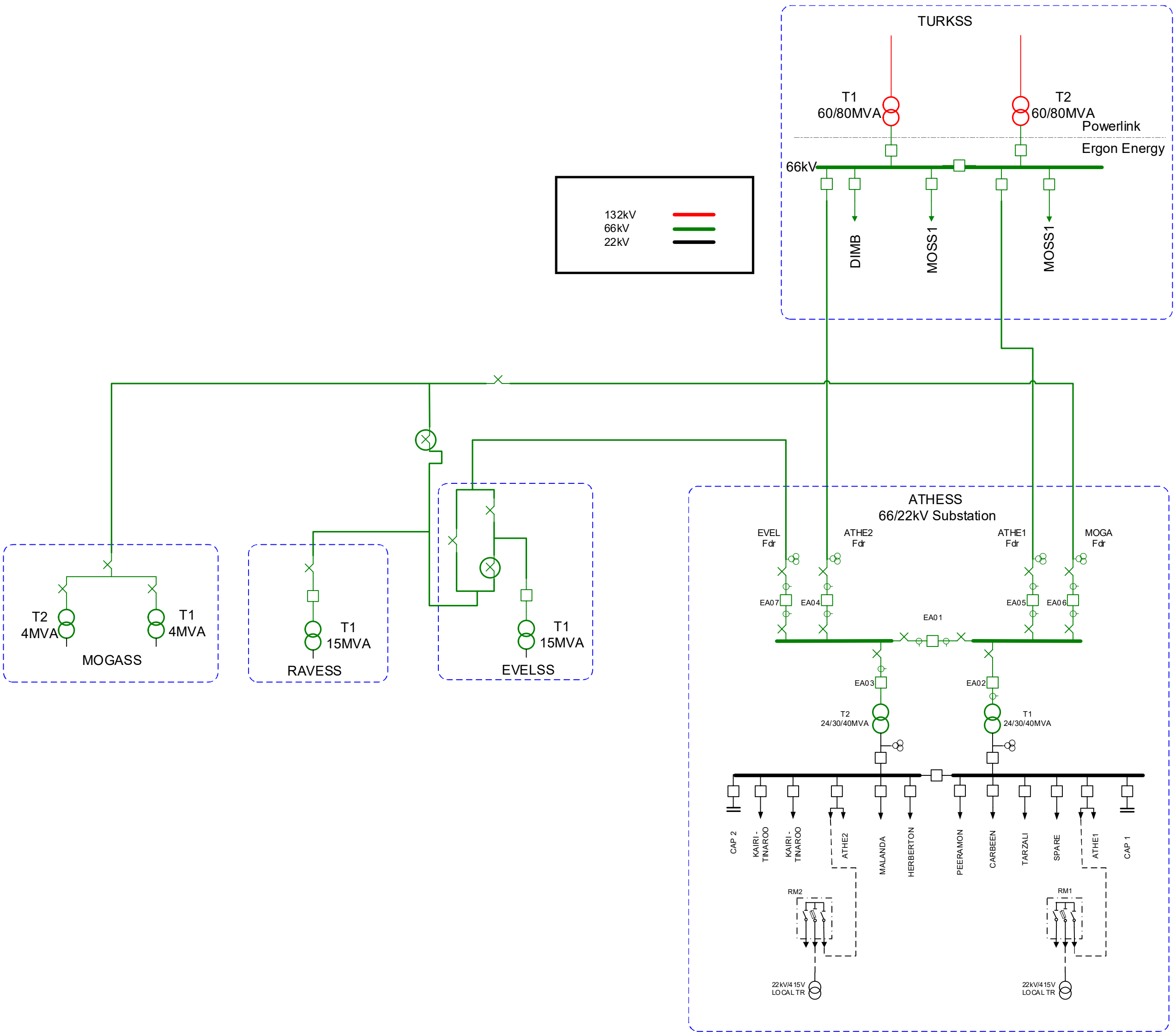


Figure 2: Existing network arrangement (schematic view)

Figure 3: ATHE layout (geographic view)

2.3. Load Profiles / Forecasts

The load at ATHE comprises a mix of residential and commercial/industrial/agricultural customers. The load is constant throughout the year, with comparable peaks in summer and winter alike, although the forecast peak load is slightly higher in winter than in summer.

The substation N-1 supply is limited by the transformers cables which have a maximum current carrying capacity of 35.6MVA. It can be seen in the following figures that even under a high forecast scenario the cable ratings are sufficient to beyond 2036.

The loads presented are the 22kV loads; however, Evelyn 66/22kV substation, Ravenshoe 66/22kV and Mount Garnett 66/22kV substation are supplied via the Atherton 66kV bus. They have peak loads expected to reach 1.6MVA, 2.3MVA and 1.9MVA respectively by 2036.

2.3.1. Full Annual Load Profile

The full annual load profile for ATHE over the 2023/24 financial year is shown in Figure 4.

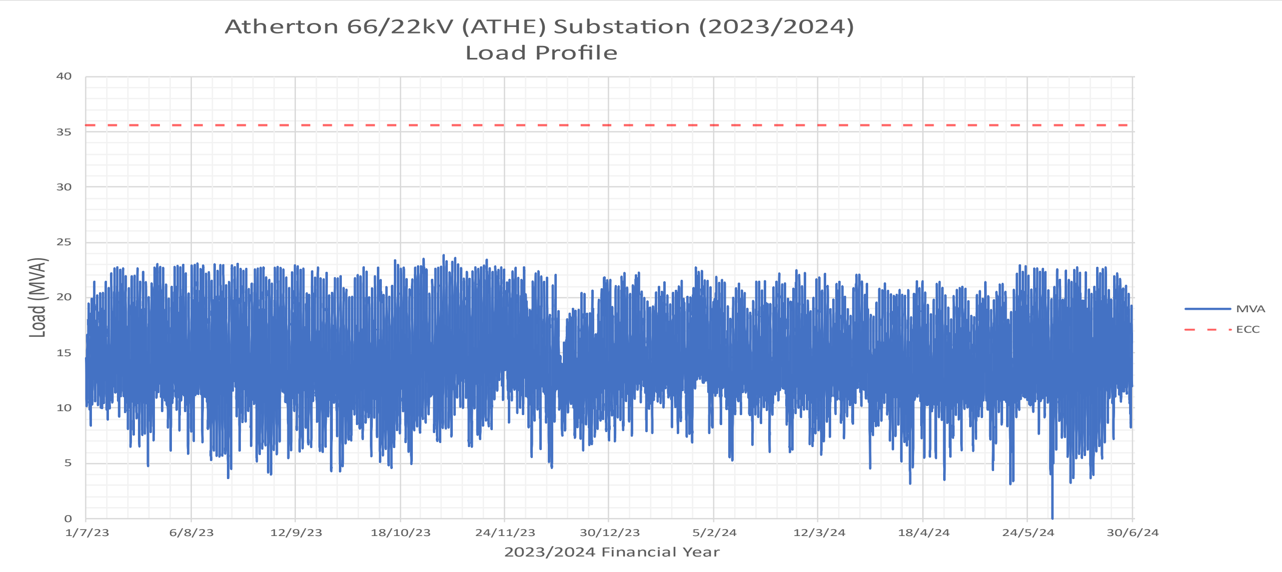


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for ATHE over the 2023/24 financial year is shown in Figure 5.

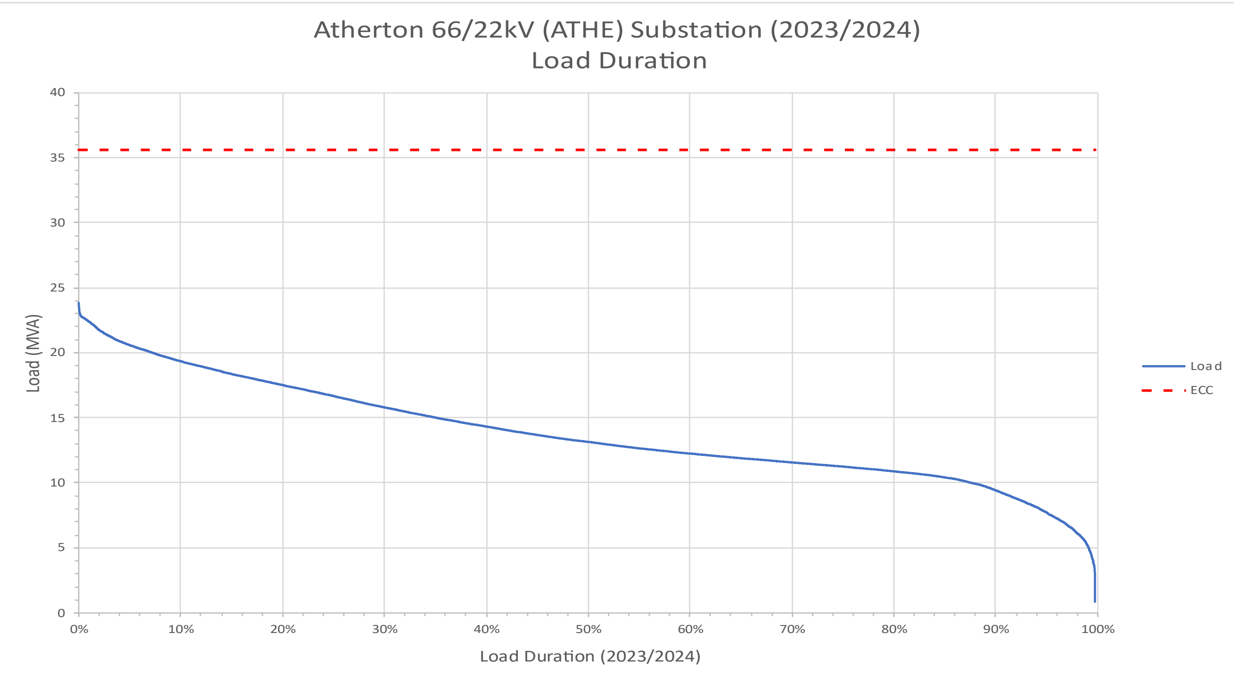


Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The summer weekday average and peak load day profiles are illustrated below in Figure 6. It can be noted that the summer peak loads at ATHE are historically experienced in the late afternoon and evening.

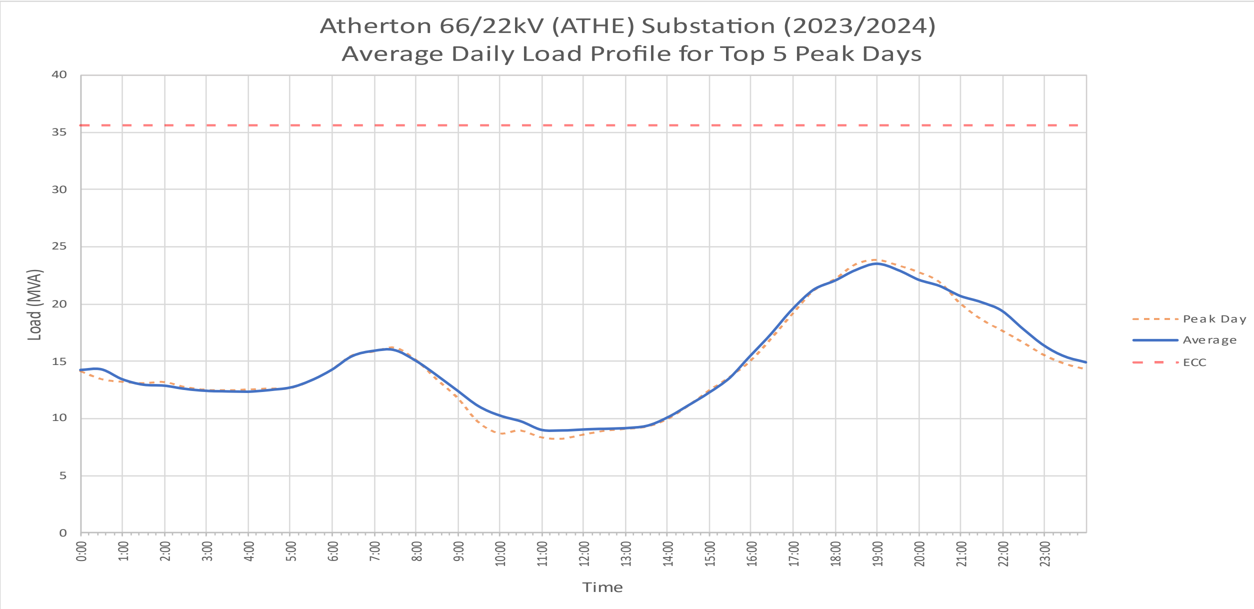


Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past five years has also been included in the graph.

It can be noted that the peak load is forecast to increase by 4MVA between 2025 to 2036.

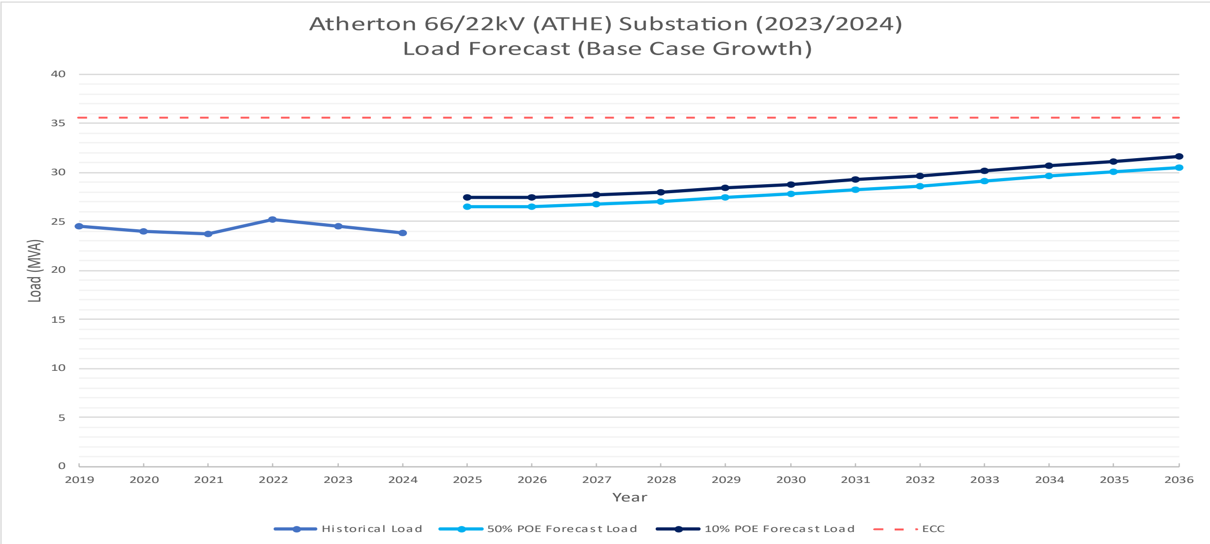


Figure 7: Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 8. With the high growth scenario, the peak load is forecast to increase by 19.5% over the next 10 years toward 35MW.

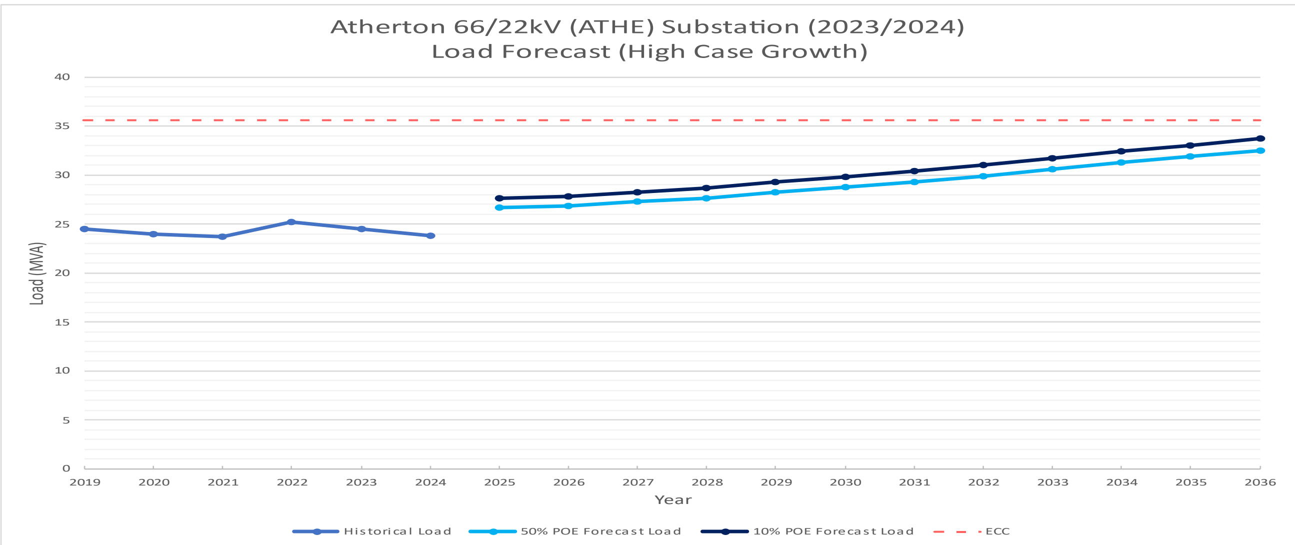


Figure 8: Substation high growth load forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 9. With the low growth scenario, the peak load is forecast to increase slightly over the next 10 years.

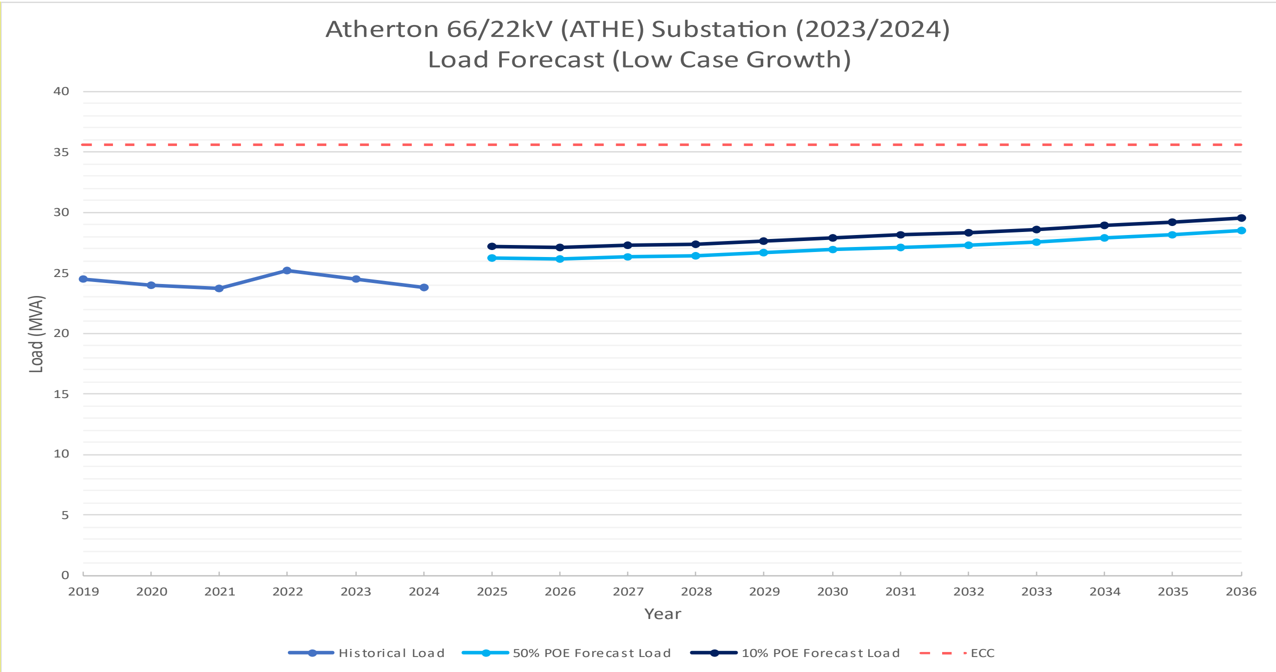


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis indicates that the following items of plant have reached retirement:

- 1 x 66kV Circuit Breaker
- 3 x 66kV Current Transformers
- 12 x 66kV Voltage Transformers
- 14 x 66kV isolators
- 1 x local services Transformer
- 25 x Protection Relays

The ASEA >HLR 84/2001 A2U Circuit Breaker which was manufactured in 1974 has a history of high contact resistance and repairing of the spring charge chain. There is a lack of spares available for the ASEA current transformers, additionally the porcelain housings of these CTs are a known safety risk due to likelihood of explosive failure. Many of the 66kV CVTs are known to be problematic, where possible Ergon has installed CVT monitoring however it is recommended where substation projects are being completed for these problematic CVTs to be replaced sooner rather than later. Inspection of the isolators shows rust and algae evident on the surface of all the isolators. These isolators are greater than 60 years of age and are likely to have high probability of failure due to weathered and corroded contacts. This poses an issue for staff when operating these isolators as they can become stuck, however also poses a reliability risk to the network as they may not be able to be closed or have poor contact after being opened to perform maintenance within the substation.

The ongoing operation of these assets beyond their estimated retirement date presents a significant risk to safety, environment and customer reliability. The continued use of problematic plant and assets beyond end of life poses safety risks to staff working within the substation. It also poses a safety risk the general public, though the increased likelihood of catastrophic failure of plant, in particular the current and voltage transformers. Ergon Energy has obligations under the *Electrical Safety Act 2002* (Qld)[5] to eliminate electrical safety risks so far as is reasonably

[5] QLD Electrical Safety Act 2002:
Part 2, Subdivision 2, Section 28 - What is reasonably practicable in ensuring electrical Safety
Part 2, Division 2, Section 29 - Duty of electricity entity

practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable. Additionally, the poor 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 ATHE. Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[6] issued under the *Electricity Act 1994* (Qld). Further to these requirements, the *Electricity Act 1994* (Qld)[7] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[8].

Where Ergon Energy identifies an imminent asset safety risk, immediate temporary measures are put in place to ensure safety of staff and public until permanent remediation can be performed.

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. Existing maintenance regime would continue and equipment that fails in service would be replaced like for like through an urgent replacement project.

3.2.1. Risk Quantification Value Streams

The risk quantification of the counterfactual at ATHE has considered three primary value streams, *reliability, financial, safety* and *environmental,* as shown in Figure 12 and described in further detail below.

- **Reliability:** The potential unserved energy from CB failure or protection operation.
- **Financial:** There are potential costs to perform unplanned emergency repairs or replacement of plant that fails in service. 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.
- **Safety:** Maintaining substation equipment beyond the recommended retirement year presents increasing safety risks to substation staff and the public. E.g., there is an increased chance of catastrophic failure of current transformers which could cause severe injuries to

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

[7] QLD Electricity Act 1994 Part 5, Division 5, Section 42(a)(i)

[8] NER:
Schedule 5.1a System Standards
Schedule 5.1 Network Performance Requirements

workers within the substation. Mal-operation of protection relays can lead to unsafe conditions on the network which presents a risk to staff and the public.

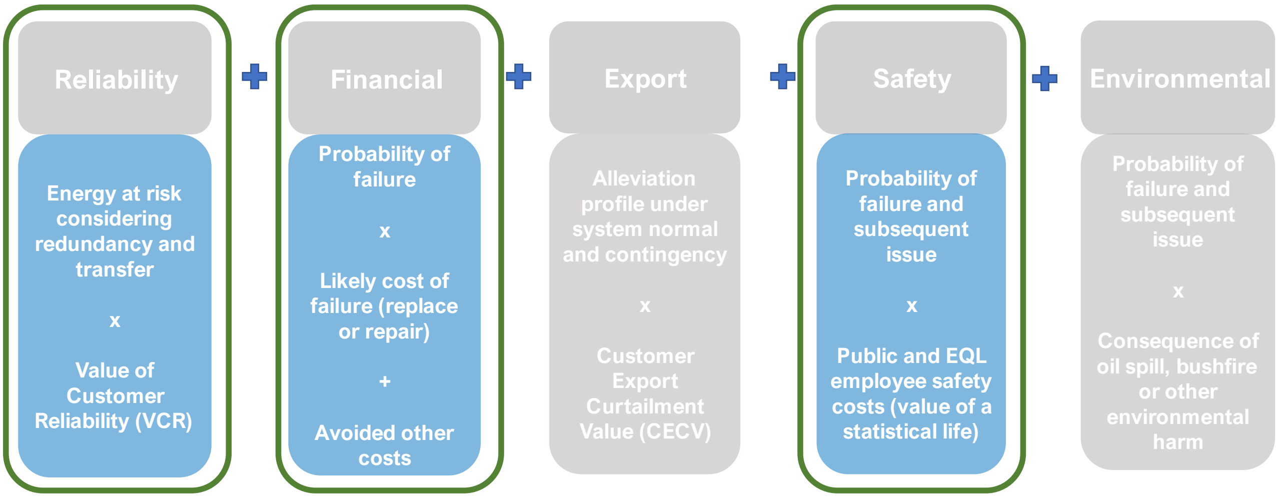


Figure 10 – Value Streams for Investment

3.2.2. Counterfactual Risk Quantification

The counterfactual risks are the expected unserved energy, emergency replacement cost, environmental risks and safety risks, during an equipment failure and associated unplanned supply outage at ATHE.

In calculating the value streams the following assumptions are used:

- **HV Circuit Breaker Forced Outage Rate** – The CB outage rate is predicted using a Weibull distribution with a Shape Parameter (β) of 4 and a gamma (γ) of 80 for 66kV CBs.
- **Restoration** – The restoration time has been set at a maximum of 48 hours. However, given remote switching available all load is restored within 2hrs for all scenarios.
- **Transfers** – depending on the outage Atherton substation can transfer between 10MVA and 15MVA on the 22kV network within 6 hours. *This would only be for a double contingency which was not studied. A double contingency is possible for loss of structures on which both 66kV feeders are located.*
- **VCR Rate** – a VCR rate of $33.50 / kWh has been used, with the mix of customers weighted towards domestic and commercial customers.
- **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.
- **Safety quantification** – Considers forced outage rate of the asset with a conversion factor of 0.1% that a fatality to an employee and/or injury to an employee will occur.
- **Risk timeframe** – risks were calculated over a 60-year period, starting from 2027 to align with the investment year of Option 1 (see below).

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 ATHE is shown in Table 1 based on the VCR values for different customer types as published by the AER.

Customers	Sector	Annual Consumption (kWh)	$/kWh (2024)
ATHE 22kV Load	Residential (Climate Zone 2)	61, 236, 559	$35.69
	Commercial*	50,147,290	$34.39
	Industrial*	12,910,970	$33.49
	Agriculture*	15,900,786	$22.25
	Average VCR		**$33.50**

Table 1: AER VCR values for ATHE

*Business using <10MVA peak demand

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

3.2.3. Safety Net Non-Compliance

Atherton substation is supplied via two 66kV feeders from Turkinje. These feeders are located on the same concrete structure and are classified as regional centre under Ergon Energy's Distribution Authority No. D01/99. On loss of a single 66kV circuit the substation can still be supplied via the alternate feed. Under safety net loss of a concrete pole is considered a non-credible contingency.

Loss of any single asset within the substation does not cause loss of supply, however it should be noted that due to the substation configuration in order to rectify loss of a feeder CB and operate isolators a full bus outage would be required for up to 2 hours. This is most likely to be completed as a planned outage, however during this time up to 15MVA of load will be at risk.

Under the preferred option the load at risk under planned work is minimised as the substation configuration will not rely on operation of the existing 66kV isolators.

3.2.4. Risk Quantification Benefit Summary

Figure 11 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2027 to 2087.

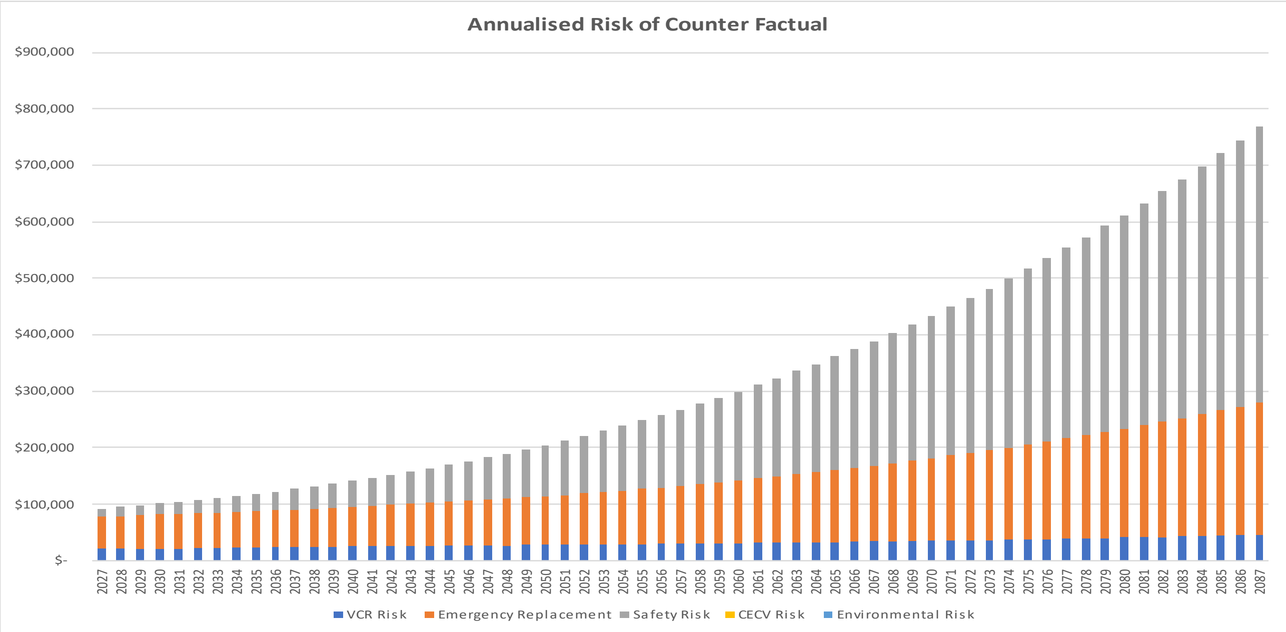


Figure 11: Annualised Risk of Counterfactual

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.

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at ATHE Substation will be consistent with the base case forecast outlined in Section 2.3.4.

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.

4. TECHNICAL CHARACTERISTICS OF SAPS AND NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a Stand-alone Power System (SAPS) or a non-network option would be required to comply with.

4.1. Size

To meet Ergon Energy's ongoing operational needs, it is expected that any SAPS or non-network credible option would need to provide stand-alone supply to the distribution network that supports a load up to the values listed in the table below.

Year	Demand Reduction Required
2027	26.82 MVA
2028	27.23 MVA
2029	27.78 MVA
2030	28.34 MVA
2031	28.87MVA
2032	29.44 MVA
2033	30.10 MVA
2034	30.79 MVA
2035	31.40 MVA
2036	32.02 MVA
2037	32.5 MVA

Table 2: Demand reduction required

The demand reduction shown in Table 7 only refers to the load supplied via Atherton 66/22kV substation. For removal of the 66kV bus at ATHE, which would most likely be required based on the limitations on 66kV assets, a further 5.8MVA load must be supplied at these remote locations.

4.2. Location

The location where network support and load restoration capability will be measured / referenced is on the incoming 66kV feeders at Atherton. As noted above for removal of the 66kV bus at Atherton the loads Evelyn, Ravenshoe and Mount Garnett must also be supplied. The location of the network support and load restoration measurement would be depended on the solution proposed and would need to be negotiated between Ergon Energy and the provider.

4.3. Timing

4.3.1. Implementation Timeframe

In order to ensure compliance with Ergon Energy's planning criteria and the National Electricity Rules, a non-network solution will need to be implemented by July 2027.

4.3.2. Duration and Time of Year

As the limitations at Atherton substation are assets which are required for supply to energise the 66kV bus and subsequently supply the entire 22kV load a non-network solution will be required to supply the entire substation load 24 hours a day throughout the entire year.

4.4. Compliance with Regulations and Standards

As a distribution network service provider, Ergon Energy must comply with regulations and standards, including the Queensland legislation, such as the *Electricity Act 1994* and the Electricity Regulation 2006, its Distribution Authority, the NER and applicable Australian Standards.

These obligations must be taken in consideration when determining the preferred option to address the identified need at Atherton as discussed in this RIT-D DPAR.

4.5. Longevity

Proposed non-network options will typically be required to provide solutions to the identified need for a period of at least 10 years. For any alternatives which include the decommissioning of Atherton Substation a minimum of 5 years advance notice for conclusion of the service is required in order to provide Ergon Energy with sufficient time to engage for alternate solutions, including building network assets. In this scenario Ergon Energy would expect providers to operate for a period of 15 years with engagement for plans beyond 15 years beginning after 10 years.

4.6. Potential Deferred Augmentation Charge

This project is driven by replacement of aged assets rather than augmentation. Deferral benefits are only applicable where the aged asset replacement can be deferred and may only be applied to a portion of the project. Until a credible non-network solution is identified deferral benefits cannot be calculated.

4.7. Feasible vs Non-Feasible Options

4.7.1. Potentially Feasible Options

Ergon Energy has not identified any feasible SAPS or non-network options to address the identified need.

4.7.2. Options that are Unlikely to be Feasible

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

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

- Renewable generation not coupled with energy storage and/or dispatchable generation
- Unproven, experimental or undemonstrated technologies

4.7.3. Timing of Feasible Options

In order to ensure compliance with Ergon Energy's planning criteria and the NER, a non-network solution will need to be implemented by July 2027.

5. CREDIBLE OPTIONS ASSESSED

5.1. Assessment of Network Solutions

Ergon Energy has identified one credible network option that would address the identified need and is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

5.1.1. Option A: 66kV Asset replacement with GIS

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid to late 2027 and would address the identified need by replacing end of life assets at ATHE. New assets would ensure Ergon Energy continues to adhere to the applicable regulatory requirements.

This option involves performing the following replacement works to address the identified need.

- Install new station services transformer
- Install new 66kV switchgear foundation
- Replace existing 66kV AIS with 66kV GIS
- Remove and replace 66kV CTs and VTs
- Install duplicate 110V DC system
- Replace Protection Relays

Due to the scope of works being entirely contained within the existing substation site at Atherton, 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. 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 $21.3 million which has been factored into the NPV to be incurred in 2027. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design completed by early 2026 and construction completed by mid to late 2027.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 12.

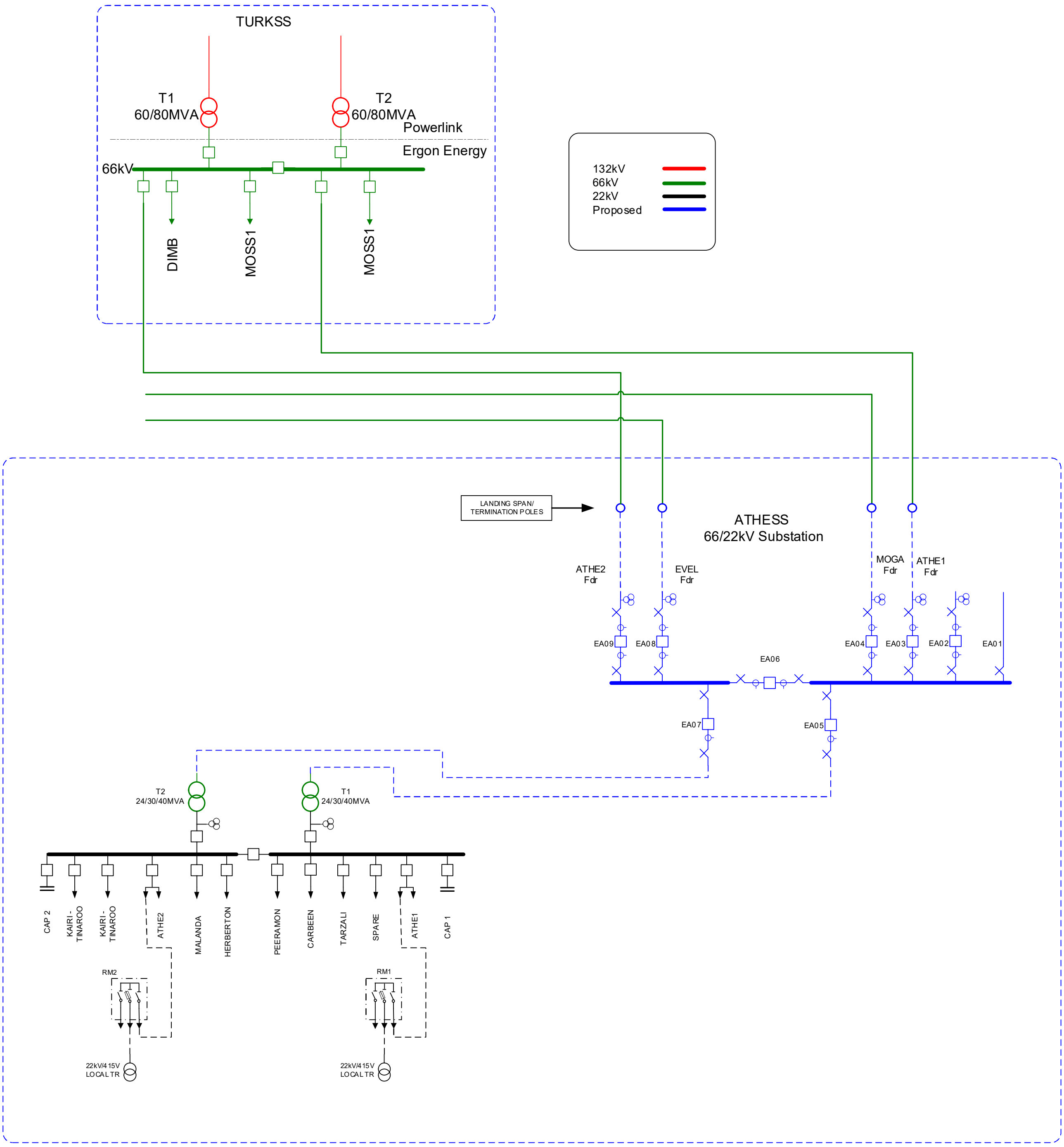


Figure 12: Option A proposed network arrangement (schematic view)

5.1.2. Options considered non-credible

It should be noted that an Air insulated Switchgear (AIS) option was considered for in-situ replacement. A civil assessment has been completed on the existing structures and has deemed these to be end of life and not suitable for assets expected to be in service for the next 40- 60 years. Installation of new isolators and circuit breakers within the existing AIS infrastructure is not possible. Furthermore, due to the spacing requirements of new assets and the staging requirements to ensure continuity of supply, replacing with AIS equipment was also not a feasible option and was therefore discounted as a non-credible option. Ergon has availability of 66kV GIS equipment available which can be installed within the existing substation.

5.2. Assessment of SAPS and Non-Network Solutions

Ergon Energy has considered Standalone Power Systems (SAPS) and demand management solutions to determine their feasibility to meet the identified need. Each of these are considered below.

5.2.1. 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 Atherton region could not be supported by a network that is not part of the interconnected national electricity system.

5.2.2. Demand Management (Demand Reduction)

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

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 Atherton customer base and considered the suitability of a number of demand management technologies. However, as the identified need is for reliability corrective action it has been determined that demand management options would not be viable propositions for the following reasons.

5.2.3. Network Load Control

While network load control can be effective in deferring augmentation projects it does not provide sufficient reduction in load to meet the identified need. Without the replacement of the aged 66kV incoming feeder circuit breaker under a loss of the remaining 66kV feeder CB all substation load (66kV and 22kV) would be unsupplied. The load reduction required to meet safety net would be approximately 30MW.

5.2.4. Demand Response

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

Customer Call Off Load (COL)

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

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. The primary driver for investment in this instance is asset safety and performance. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed).

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

Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets.

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

Customer Solar Power Systems

A total of 3,444 residential customers have solar photo voltaic (PV) systems for a connected inverter capacity of 18,838kVA and 281 business customers with a total inverter capacity of 6,834kVA.

The daily peak demand is driven by residential and commercial customer demand and the peak generally occurs between 6:00pm and 9:00pm. 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 a fewer customers and therefore are cheaper and easier to engage and contract.

However, only a small percentage of customers in this supply area have solar PV systems and possibly none have a BESS. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has a very limited solar/BESS. 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.

5.2.5. 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 Atherton area to address the identified need.

5.3. Preferred Network Option

Ergon Energy's preferred option is Option A, to replace the 66kV AIS with 66kV GIS, replace 66kV CTs and VTs, replace local service transformer and replace end of life protection relays by 2027.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at ATHE ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. 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 $21.3 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design completed by early 2026 and construction completed by mid to late 2027.

6. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO SCREENING FOR OPTIONS REPORT

On 30 January 2025, Ergon Energy published the Screening for Options Report providing details of the identified need. This Report sought information from interested parties about possible alternative potential credible options to address the identified need.

In response to the Screening for Options Report, Ergon Energy received no comments from providers.

6.1. Submissions Received which are Potential Credible Options

6.1.1. Credible Submission Name

Credible submission details

6.2. Submissions Received which are not Potential Credible Options

6.2.1. Non-Credible Submission Name

Non-credible submission details

7. 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.

7.1. 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

7.1.1. 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 $33.50/kWh for the ATHE 22kV load, which has been derived from the AER 2024 VCR values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

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

7.2. 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
- Other Class of Market Benefit

7.2.1. Changes in Voluntary Load Curtailment

The credible option presented in this RIT-D assessment does not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Atherton area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

7.2.2. Changes in Costs to Other Parties

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

7.2.3. Differences in Timing of Expenditure

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

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

The credible option included in this RIT-D assessment is 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 Atherton area.

7.2.5. Changes in Electrical Energy Losses

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

7.2.6. Changes in Australia's Greenhouse Gas Emissions

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

7.2.7. 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 change[9].

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.

7.2.8. Cost Associated with Social Licence Activities

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

8. DETAILED ECONOMIC ASSESSMENT

8.1. 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 calculation of the credible option has been undertaken.

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

8.2. Key Variables and Assumptions

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

The present value 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.

8.3. Net Present Value (NPV) Results

An overview of the NPV results are provided in Table 3. The only credible option assessed, Option A, shows a negative net NPV of $16,052,000 and is the recommended development option to address the identified need.

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	66kV Asset Replacement with GIS	1	-$16,052,000	-$21,632,000	-$991,000	$6,572,000

8.4. Selection of Preferred Option

Ergon Energy’s preferred option is Option A, to replace the 66kV AIS with 66kV GIS, replace 66kV CTs and VTs, replace local service transformer and replace end of life protection relays by 2027. The substation yard and earth-grid will be extended to accommodate the new switchgear building and new 66kV switchyard.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at ATHE ensuring Ergon Energy continues to adhere to the applicable regulatory instruments. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. 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 $21.3 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design completed by early 2026 and construction completed by mid to late 2027.

8.5. 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.

9. SUBMISSION AND NEXT STEPS

9.1. Submissions from Solution Providers

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

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

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

Submissions in writing are due by 4pm on the **18 March 2025** and should be lodged to demandmanagement@ergon.com.au

9.2. Next Steps

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

Ergon Energy intends to publish the FPAR no later than 30 March 2025. Ergon Energy will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Ergon Energy.

At the conclusion of the consultation process, Ergon Energy intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary.

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

Step 2	Release of Draft Project Assessment Report (DPAR)	Date Released: **18 March 2025**
Step 3	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 4	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **30 March 2025**
Ergon Energy reserves the right to revise this timetable at any time. The revised timetable will be made available on the Ergon Energy RIT-D website.		

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

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

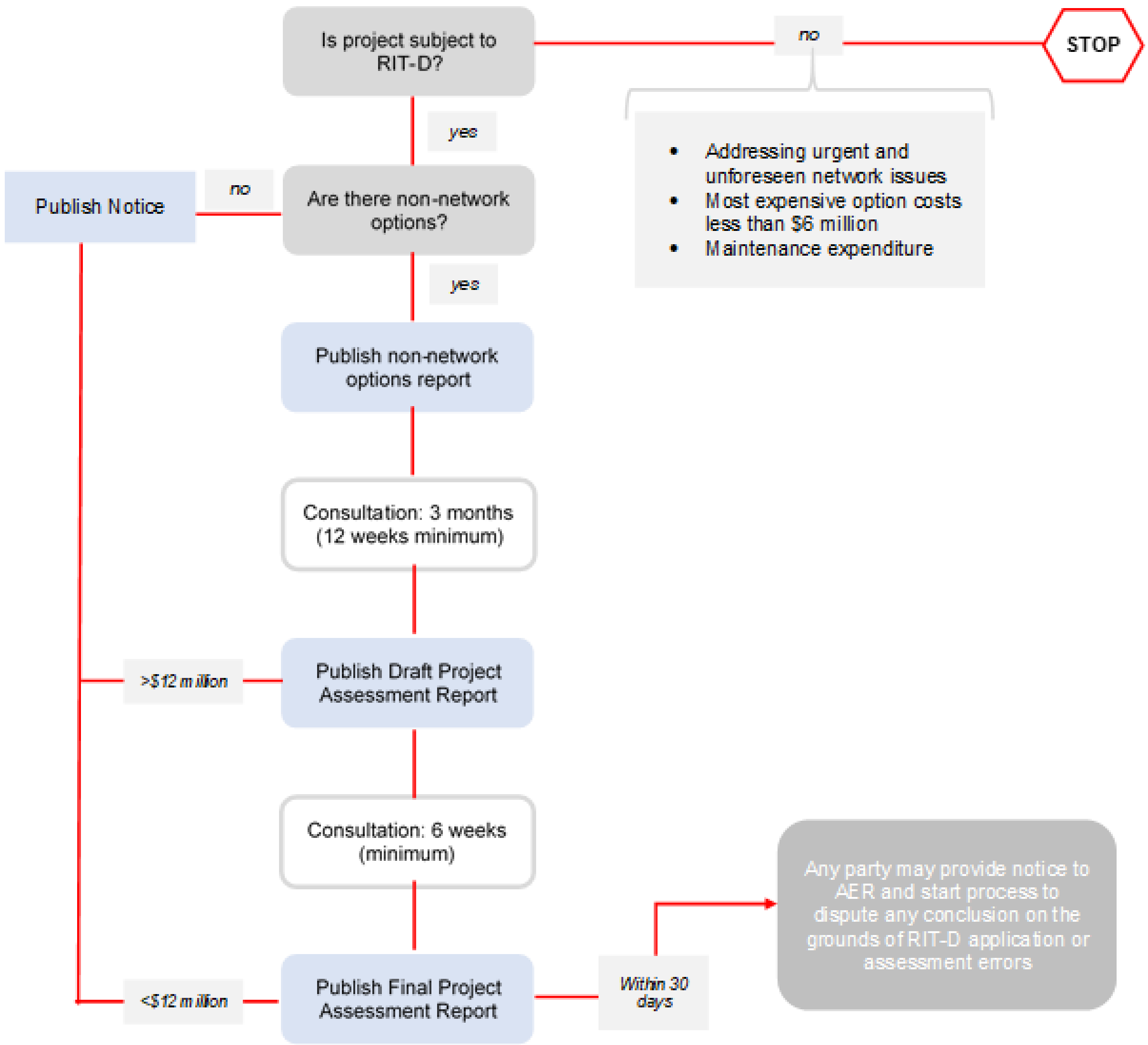
10. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the Options Screening Report;	6
(4) a description of each credible option assessed	5 & 6
(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	7
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	3.3 & 5
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	7
(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	7.2

(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	8
(10) the identification of the proposed preferred option	8.4
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	8.4 & 8.5
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	9.1

APPENDIX A – THE RIT-D PROCESS



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