# Regulatory Investment Test for Distribution (RIT-D)

# Addressing Reliability Requirements in the Degilbo Network Area

## Notice of Screening for Options

19 December 2024

Part of Energy Queensland

# EXECUTIVE SUMMARY

## About Ergon Energy

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

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

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

## Identified Need

Degilbo is a rural township in the North Burnett region of Queensland, known for its mining, agricultural and animal industries. Degilbo 66/11kV zone substation (DEGI) supplies approximately 1,248 customers in total, as well as major load and generator customers. It delivers 12GWh of energy annually, predominantly domestic (44%), commercial (39%) and industrial (16%) load. The continued operation of DEGI is critical to supply of customers in the North Burnett area.

Condition Based Risk Management (CBRM) analysis indicates that the two 2MVA 66/11kV transformers (T1 and T2) and the two 10.57/11kV auto-transformers (AT1 and AT2) are reaching end of life.

The Hawker Siddeley Falcon Beta 2 indoor 11kV ring main unit (RMU) is a make with a known design issue where the CB earth switch contacts can overtravel and contact the live busbar when being switched OFF and are classified as problematic plant.

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 of the power transformers / auto-transformers and 11kV RMU. Ergon Energy has obligations under the Electrical Safety Act 2002 (Qld)[1] to eliminate

[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

electrical safety risks so far as is reasonably practicable, and where not reasonably practicable, to minimise the risks so far as is reasonably practicable.

There is a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. 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 DEGI. Ergon Energy has obligations to comply with the reliability performance standards specified in its Distribution Authority[2] issued under the Electricity Act 1994 (Qld). Further to these requirements, the QLD Electricity Act 1994[3] stipulates that distribution entities must comply with the reliability requirements, system standards and performance requirements specified in the National Electricity Rules (NER)[4].

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 (National Electricity Rules, Electricity Act 1994 (Qld), 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 Degilbo supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D. An internal assessment has been conducted and it has been determined that there is no stand-alone power system (SAPS) or non-network option that is potentially credible, or that forms a significant part of a potential credible option that will meet the identified need or form a significant part of the solution. This Notice has hence been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(d) of the NER.

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

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

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# 1. BACKGROUND

## 1.1. Geographic Region

Degilbo is a rural township in the North Burnett region of Queensland, known for its mining, agricultural and animal industries. Degilbo 66/11kV zone substation (DEGI) supplies approximately 1,248 customers in total, including the nearby town of Biggenden, as well as major load and generator customers. It delivers 12GWh of energy annually, predominantly domestic (44%), commercial (39%) and industrial (16%) load. The continued operation of DEGI is critical to supply of customers in the North Burnett area. The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in Figure 1.

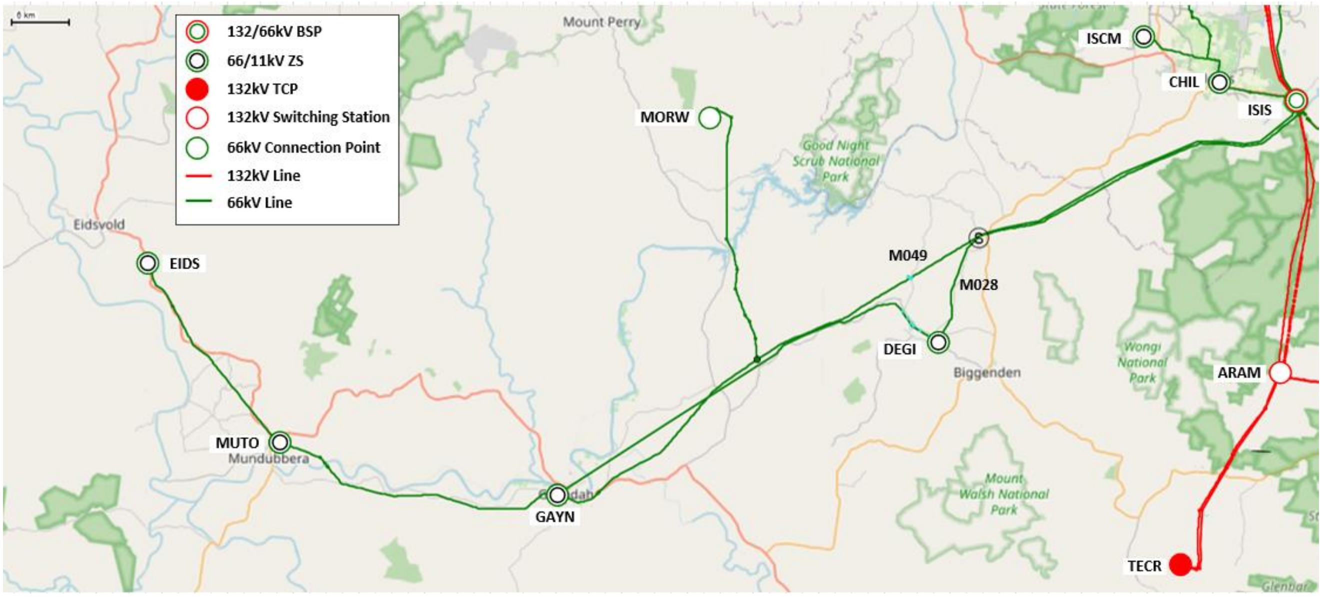



**Figure 1: Geographic of the North Burnett area sub-transmission network**

## 1.2. Existing Supply System

DEGI is supplied at 66kV from Isis 132/66kV bulk supply point (ISIS) by a tee from M028 (Isis to Gayndah) 66kV feeder. A second Isis to Gayndah 66kV feeder, M049, is run in parallel with M028. Figure 1 shows the geographic layout of the North Burnett area 66kV network.

Figure 2 gives a line diagram of DEGI and shows that there are four outgoing, 11kV distribution feeders. These feeders supply Degilbo, Biggenden, nearby rural properties, as well as major load and generator customers.

DEGI is equipped with two, non-bunded, 2MVA 66/11kV transformers (T1 and T2) and two, 2MVA 10.57/11kV auto transformers (AT1 and AT2). A 66kV strung-bus supplies each transformer via a HV fuse and connects to a fault throw switch (FTS). There is an indoor 11kV switchboard housed inside a switchgear and control building.

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

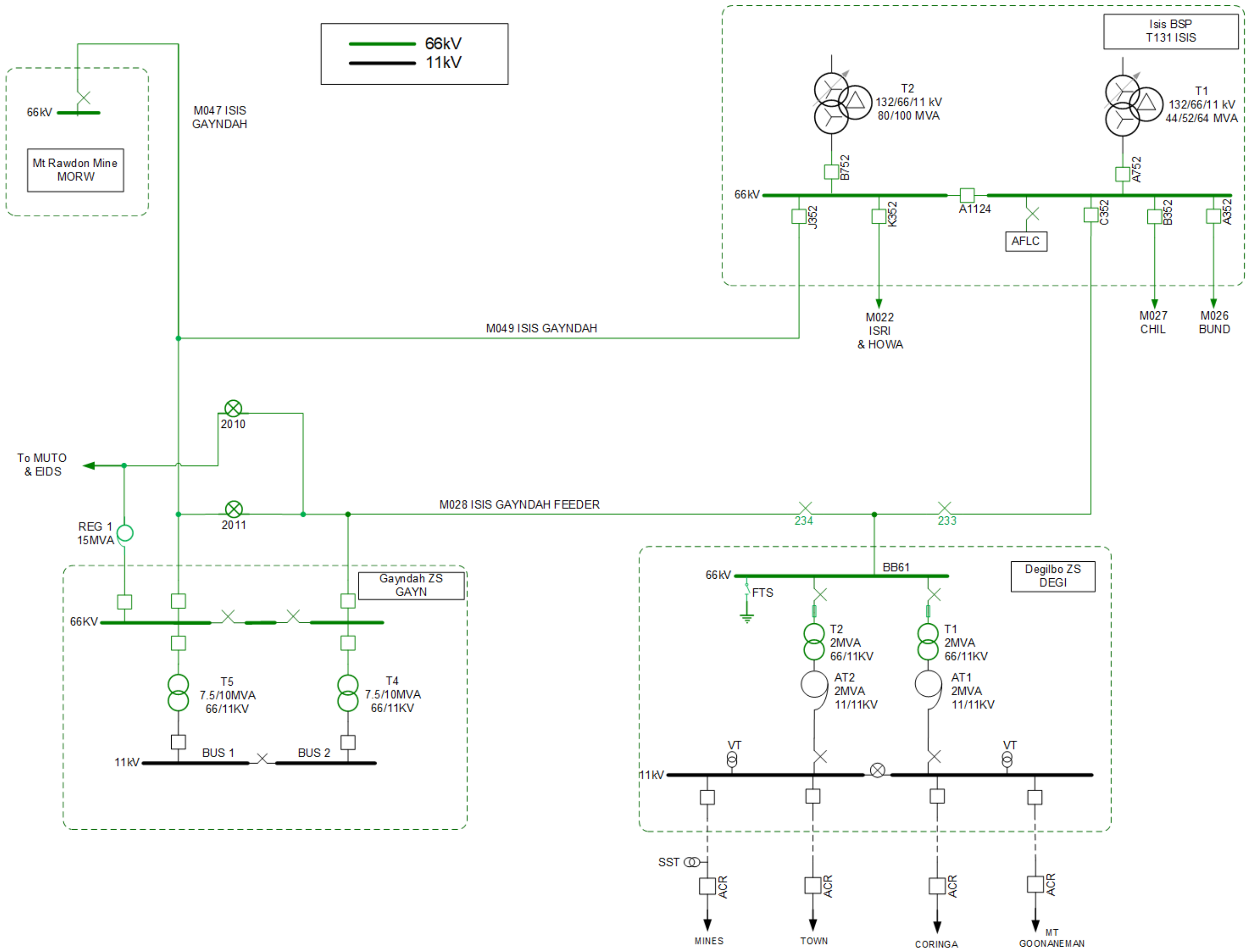



**Figure 2: Existing network arrangement (schematic view)**

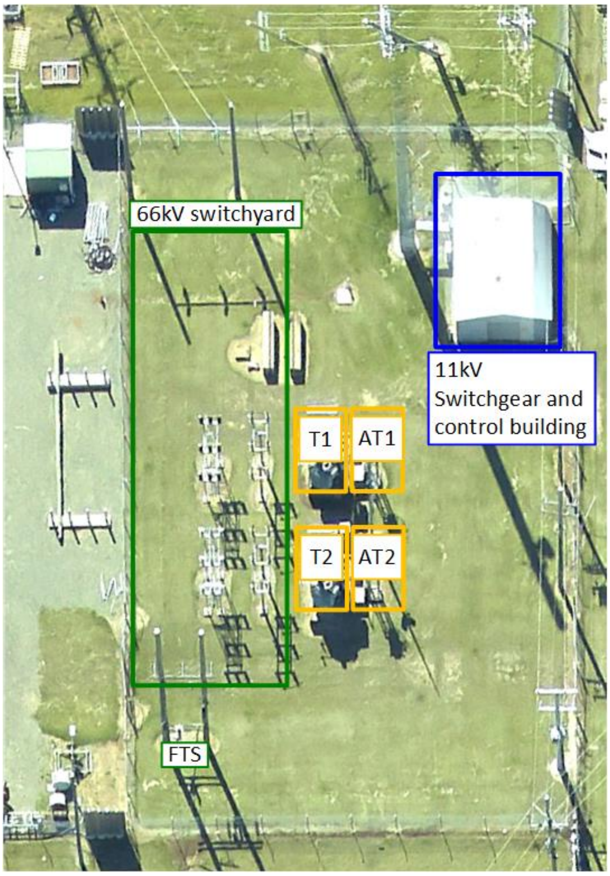



**Figure 3: DEGI layout (geographic view)**

## 1.3. Load Profiles / Forecasts

The load at DEGI comprises a mix of residential and commercial/industrial customers. The load is summer peaking.

### 1.3.1. Full Annual Load Profile

The full annual load profile for DEGI over the 2023/24 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

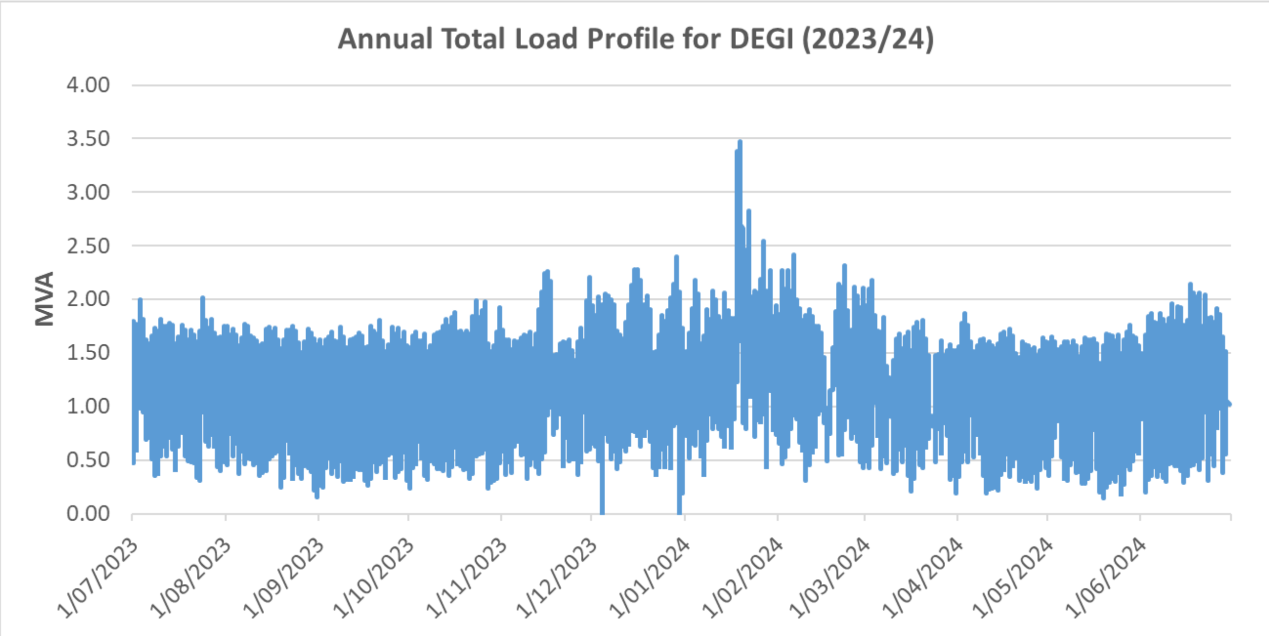



**Figure 4: Substation annual load profile (2023/24)**

### 1.3.2. Load Duration Curve

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

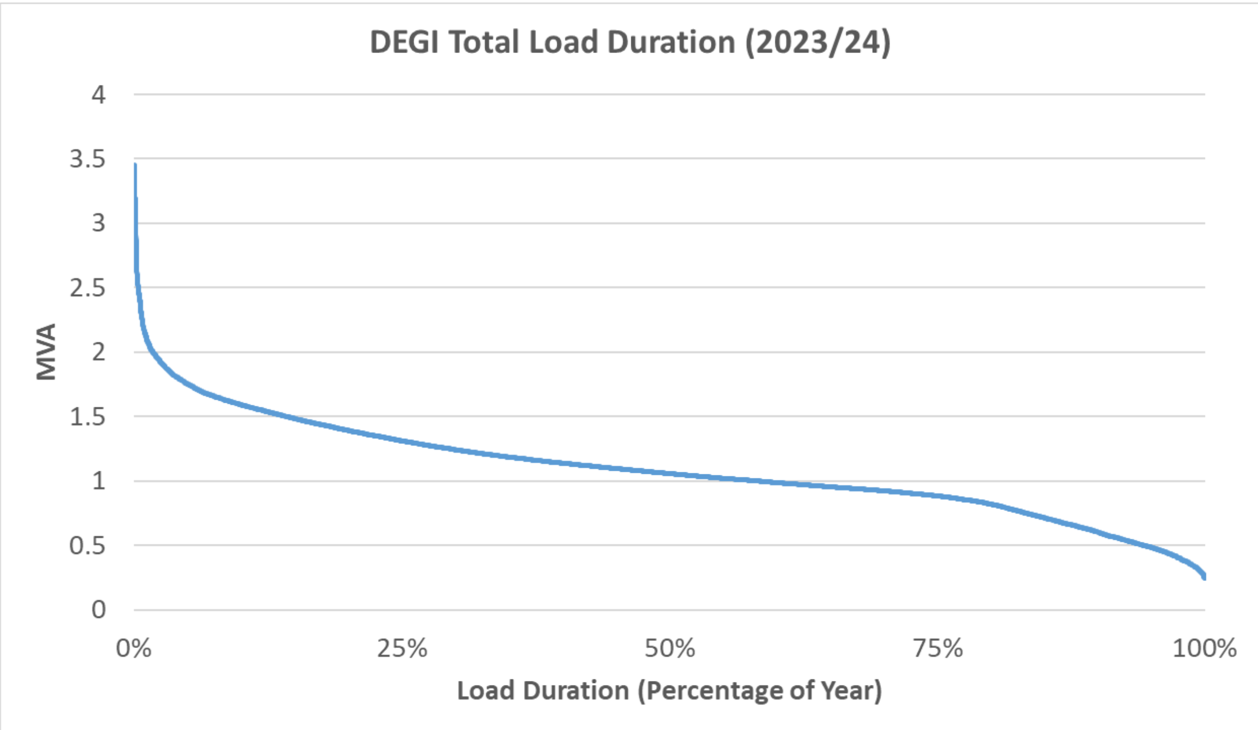



**Figure 5: DEGI load duration curve**

### 1.3.3. 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 DEGI are historically experienced in the late afternoon and evening.

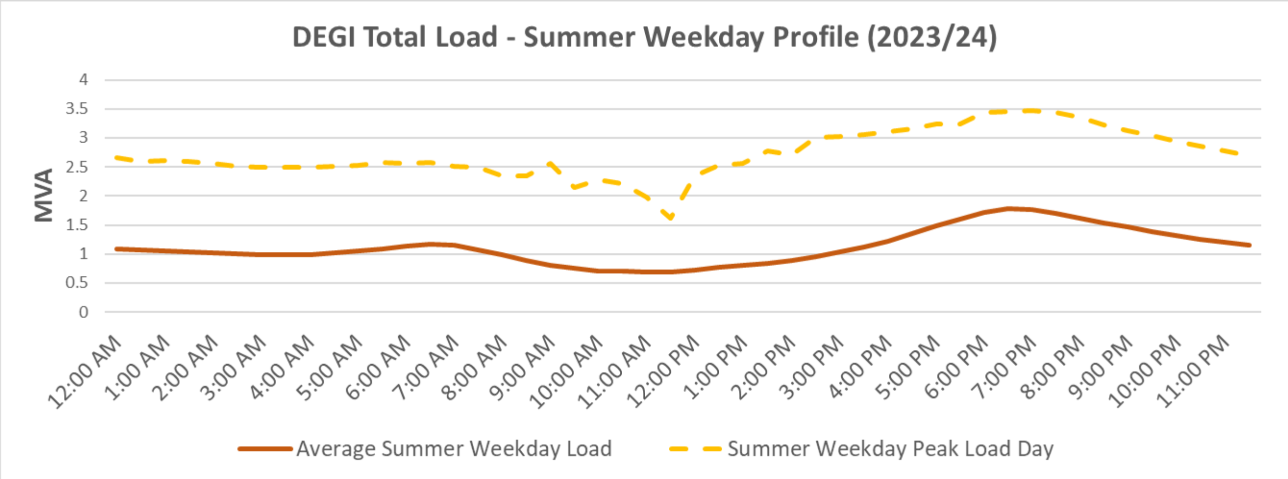



**Figure 6: Substation average peak weekday load profile (summer)**

### 1.3.4. 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 0.7MVA from 2025 to 2026 (due to a new load connection planned) followed by a period of near zero growth from 2026 onwards under the base case scenario.

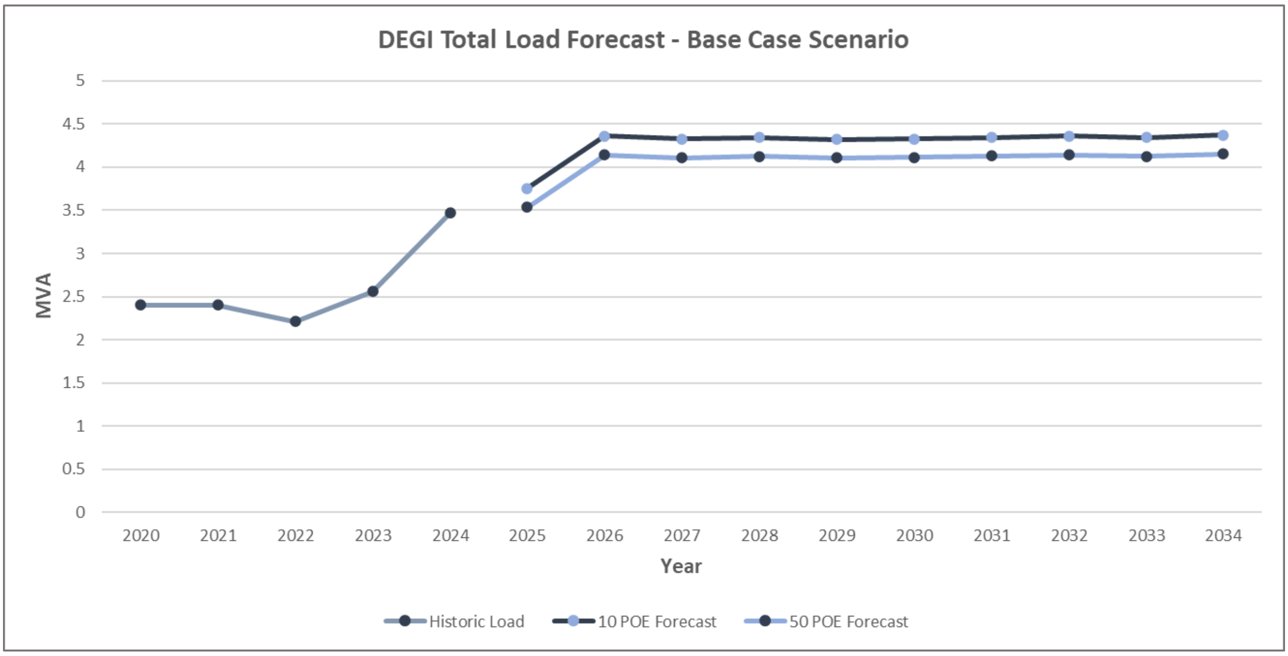



**Figure 7: Substation base case load forecast**

### 1.3.5. 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 slightly over the next 10 years.

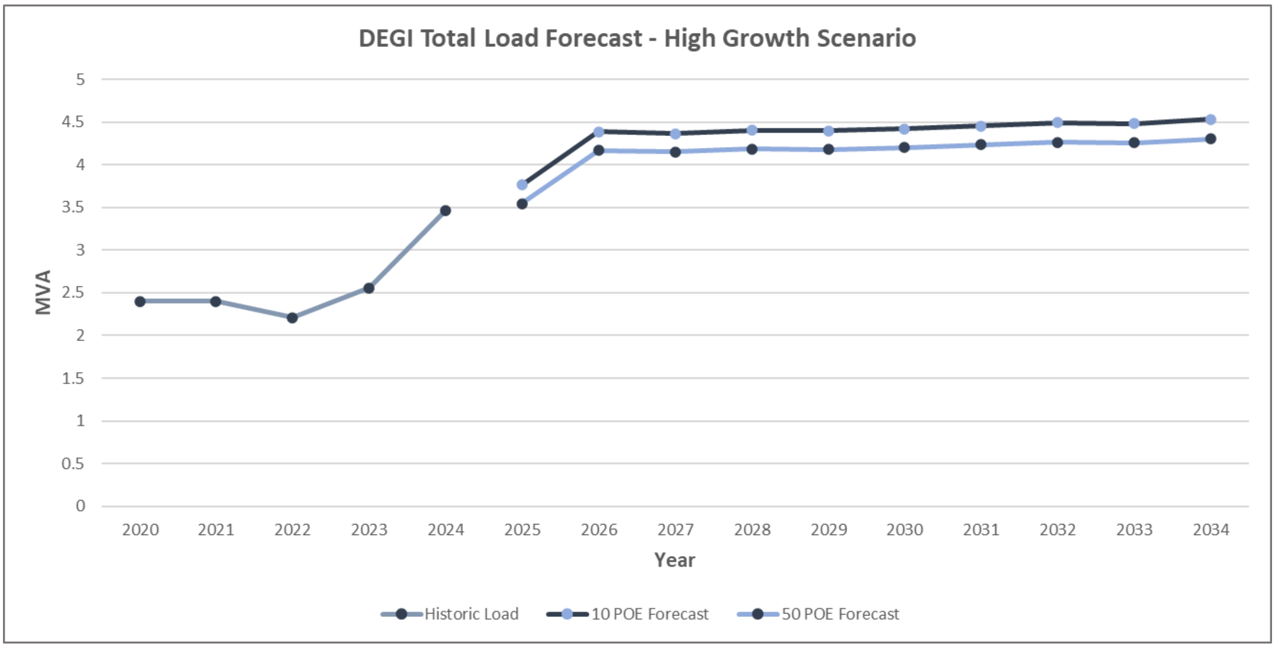



**Figure 8: Substation high growth load forecast**

### 1.3.6. 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 decline slightly over the next 10 years.

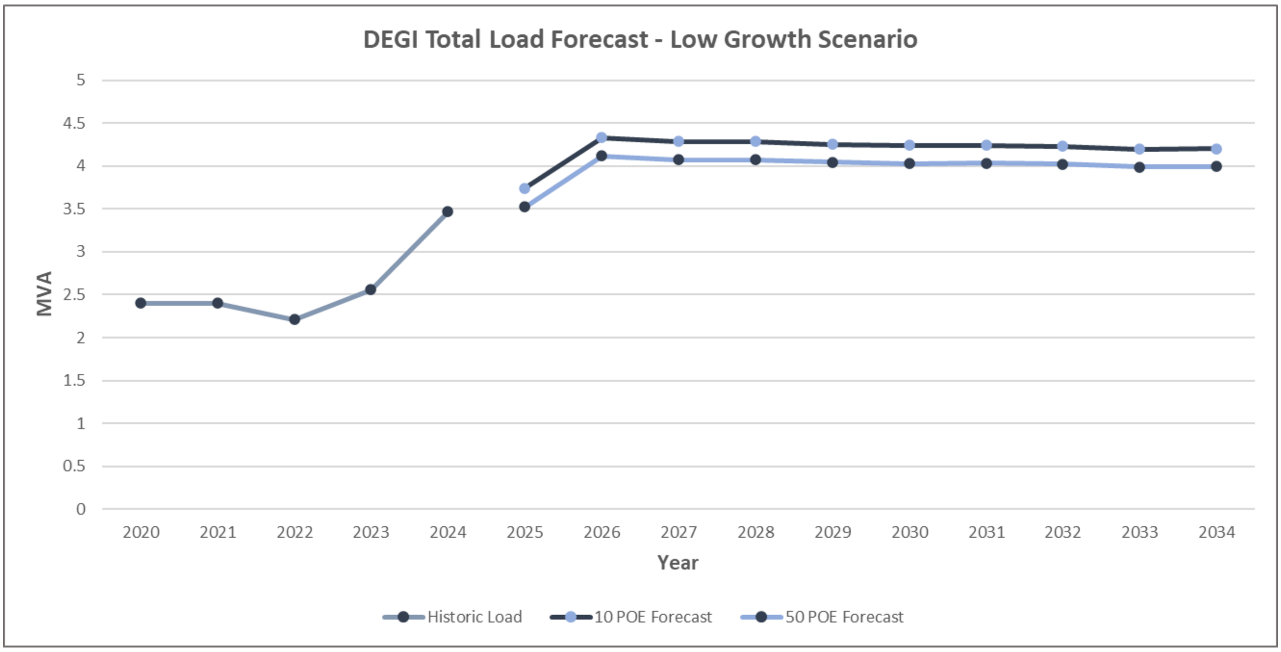



**Figure 9: Substation low growth load forecast**

# 2. IDENTIFIED NEED

## 2.1. Description of the Identified Need

### 2.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis indicates that the two 2MVA 66/11kV transformers (T1 and T2) and the two 10.57/11kV auto-transformers (AT1 and AT2) are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents a significant risk to safety, environment and customer reliability.

- 2 x 66/11kV transformers (T1, T2) (estimated retirement year 2028)
- 2 x 10.57/11kV auto-transformers (AT1, AT2) (estimated retirement year 2031)

The indoor 11kV RMU is a Hawker Siddeley Falcon Beta 2 make with 1999 YOM. This particular model is classified as being problematic due to having a known issue where the CB earth switch contacts can overtravel and contact the live busbar when being switched OFF, inadvertently energising unterminated or earthed cables connected to the CB. To minimise safety risks to field staff, special instructions must be followed when accessing or operating the RMU. These additional steps must be undertaken which adds additional complexity and expense during routine work. If these additional steps are not performed correctly then there is an increased risk of a catastrophic failure of the RMU, posing serious safety risks to any nearby field staff. Asset Maintenance and Engineering Field Support have advised that the switchboard should be replaced as part of this project.

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 of the power transformers / auto-transformers and 11kV RMU. Ergon Energy has obligations under the Electrical Safety Act 2002 (Qld)[5] 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.

There is a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. 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 DEGI. Ergon Energy has obligations to comply with

[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

the reliability performance standards specified in its Distribution Authority[6] issued under the Electricity Act 1994 (Qld). Further to these requirements, the QLD Electricity Act 1994[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.

[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

# 3. POTENTIAL CREDIBLE OPTIONS

## 3.1. Non-Network Options Identified

Ergon Energy has not identified any viable non-network solutions internally that will provide a complete or a hybrid (combined network and non-network) solution to address the identified need. Further discussion of non-network options is included in Section 4.

## 3.2. Network Options Identified

Ergon Energy has identified one potential credible option that would address the identified need.

### 3.2.1. Option A: Asset replacement

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

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

- Replace T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers,
- Replace the 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building,
- Build a new 66kV switchyard,
- Extend the substation yard and earth-grid to accommodate the new switchgear building and new 66kV switchyard.

Due to the scope of works being entirely contained within the existing substation site at Degilbo, 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.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 10.

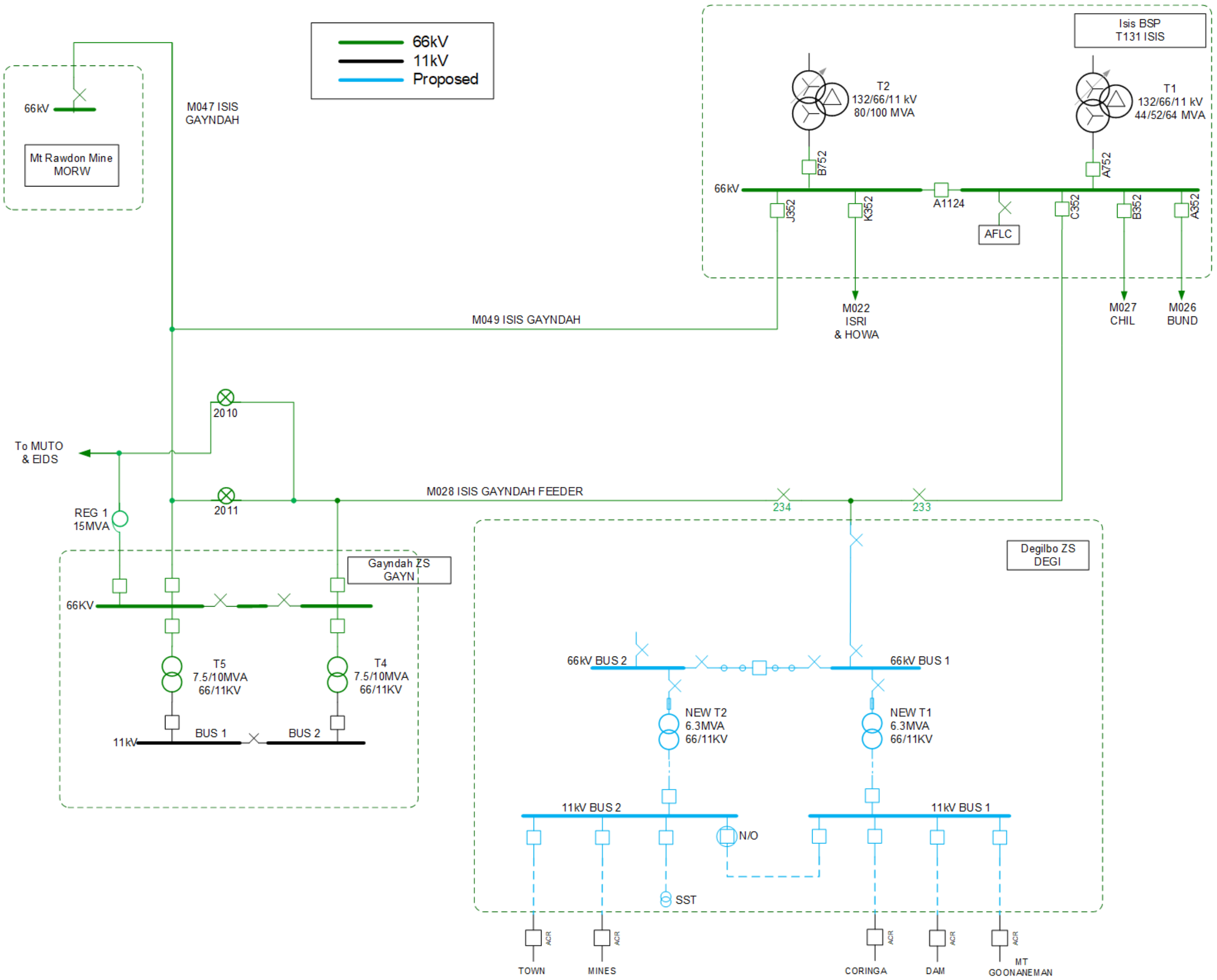



**Figure 10: Option A proposed network arrangement (schematic view)**

## 3.3. Preferred Option

Ergon Energy's preferred option is Option A, to replace T1 / AT1 and T2 / AT2 with two new 6.3MVA 66/11kV transformers, build a new 66kV switchyard and replace the 11kV RMU indoor switchboard with new 12kV Ring Main Switchgear installed within a new prefabricated switchgear building at DEGI 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 DEGI 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, are commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $10.7 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 mid-2026 and construction completed by mid-2027.

# 4. ASSSESSMENT OF SAPS AND NON-NETWORK SOLUTIONS

Ergon Energy has considered SAPS and demand management solutions. Each of these are considered below.

## 4.1. 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 Degilbo region 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.

## 4.2. 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 Degilbo 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.

### 4.2.1. Network Load Control

The residential customers and commercial load appear to drive the daily peak demand which generally occurs between 6:00pm and 9:00pm.

There are 667 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 400kVA[9] is available.

Degilbo Substation LC signals are controlled from ISIS bulk supply point. 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 load at ISIS exceeds 51.5MW. This strategy does not directly address demand peaks experienced at Degilbo. Tariff 33 air-conditioning

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

channels are under manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

## 4.3. 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.

### 4.3.1. 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.

### 4.3.2. 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.

### 4.3.3. 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.

### 4.3.4. Customer Solar Power Systems

A total of 342 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 1,707kVA.

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.

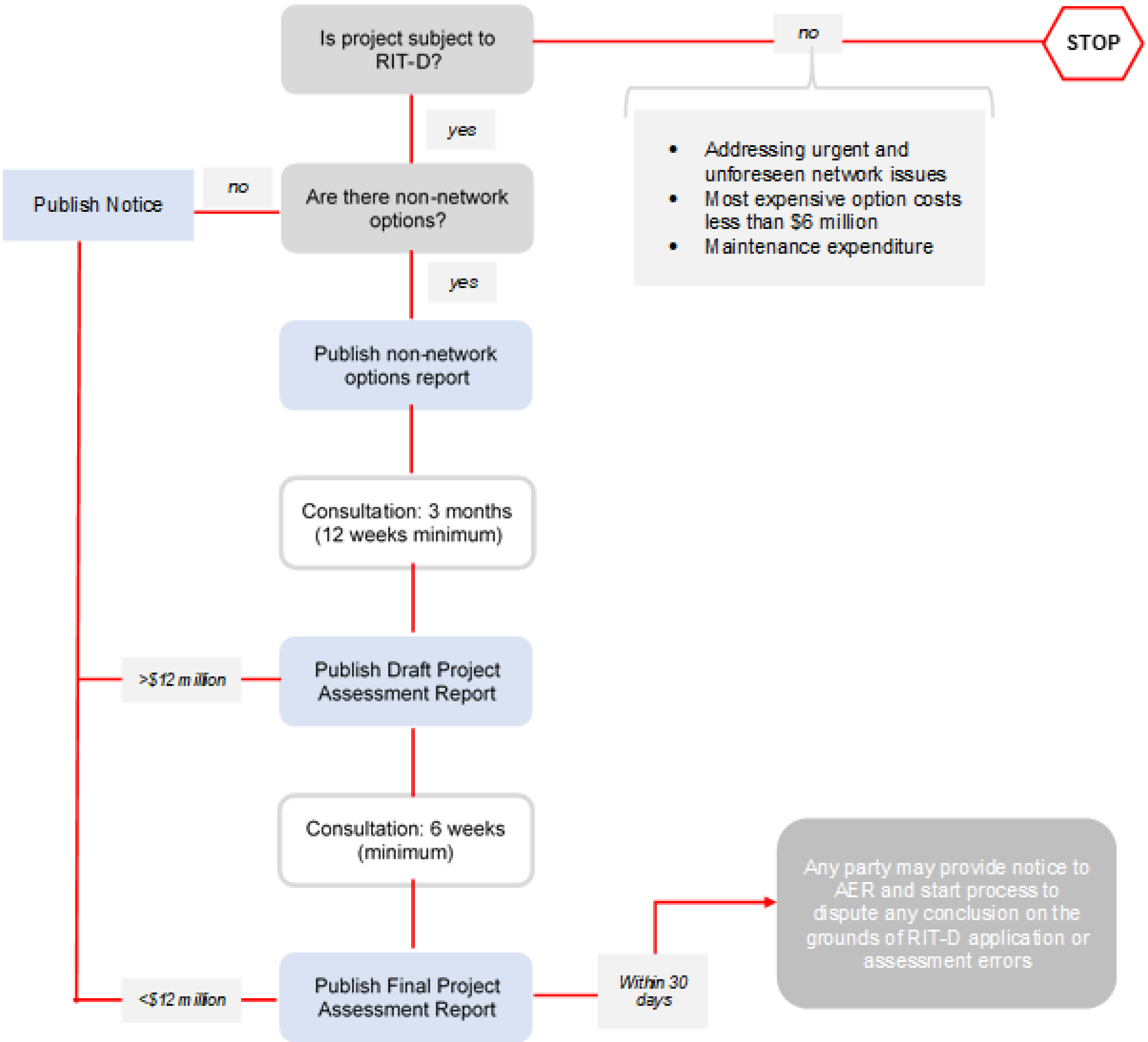
## 5. CONCLUSION AND NEXT STEPS

Ergon Energy has determined that there would not be a non-network option or SAPS option that is a potential credible option, or that forms a significant part or a potential credible option, to address the identified need.

The preferred credible option is Option A – asset replacement.

This Notice of Screening for options is published in accordance with rule 5.17.4(d) of the National Electricity Rules. As the next step in the RIT-D process, Ergon Energy will publish a 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.