Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Craiglie Network Area

Notice of No Non-Network or SAPS Options

25 July 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

Craiglie 132/22kV Substation (CRAI) provides electricity supply to approximately 4,462 customers in the Port Douglas area, of which 3,734 are residential and 728 are commercial and industrial. CRAI supplies 97.8 GWh of energy annually, with 33% of this energy consumed by residential customers.

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20MVA English Electric 132/22kV transformers (YOM 1967) and protection relays at CRAI are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents significant safety, environmental and customer reliability risks.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation. 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.

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 CRAI. The CRAI transformers also have a 2.1MVA reverse power flow limitation due to their single switching resistor type tap changers, which could limit export from future customer PV systems.

[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

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Ergon Energy has obligations to comply with reliability performance standards specified in its Distribution Authority[2] issued under the *Electricity Act 1994* (Qld). Further to these requirements, the *Electricity Act 1994* (Qld)[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 Craiglie 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

Craiglie 132/22kV Substation (CRAI) provides electricity supply to approximately 4,462 customers in the Port Douglas area, of which 3,734 are residential and 728 are commercial and industrial. CRAI supplies 97.8 GWh of energy annually, with 33% of this energy consumed by residential customers.

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

Figure 1: Existing network arrangement (geographic view)

1.2. Existing Supply System

CRAI is located in the Port Douglas area in Far North Queensland and is supplied by a double circuit 132kV feeder from T055 Turkinje 132/66kV Substation (TURK).

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CRAI was established in1996 according to applicable design and construction standards during that time. CRAI consists of 2 x 132/22kV 15/20MVA (ONAN/ONAF) power transformers and an indoor 22kV switchboard with 5 x 22kV feeders.

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

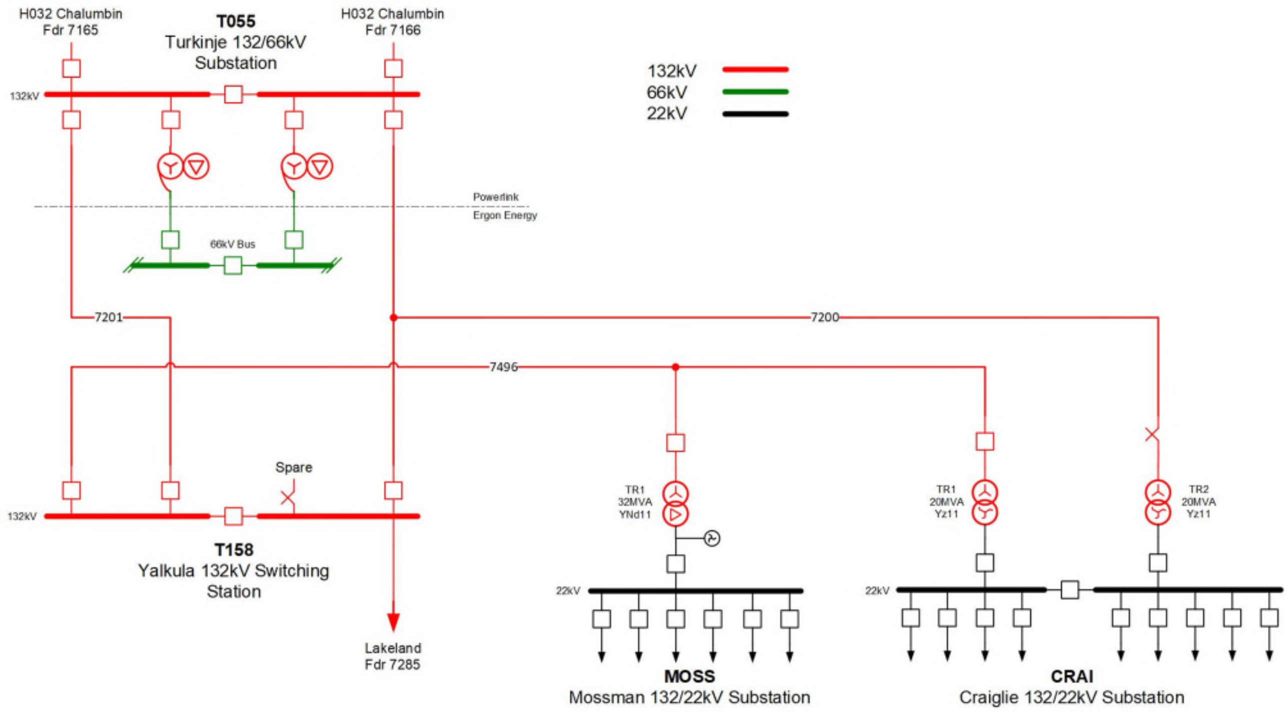

Figure 2: Existing network arrangement (schematic view)

Figure 3: Craiglie Substation (geographic view)

1.3. Load Profiles / Forecasts

The load at CRAI comprises a mix of residential and commercial customers. The load is Summer peaking, and the annual peak loads are predominantly driven by residential and commercial load. The annual minimum load generally occurs during the Winter period around 3am in the morning, however this is forecast to shift to the Winter midday period once export from rooftop solar PV systems starts to exceed the daytime load in the area.

1.3.1. Full Annual Load Profile

The full annual load profile for CRAI over the 2023/24 and 2024/25 financial years is shown in Figure 4. Note that since mid-2024 CRAI has temporarily supplied some of the Mossman substation load while works are undertaken at Mossman substation, therefore the load for this period is higher than the normal CRAI load.

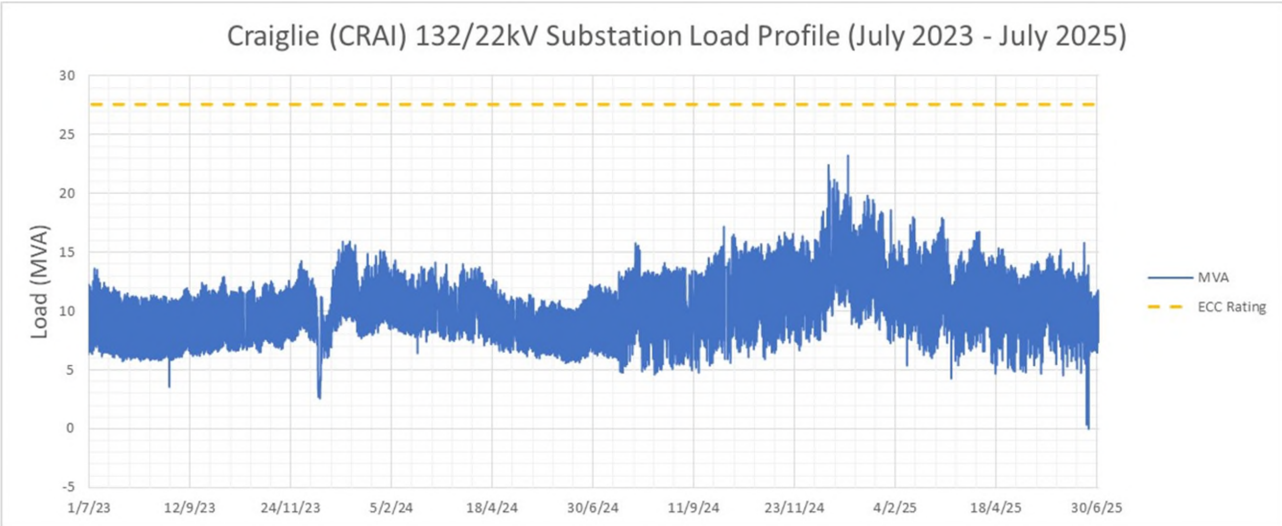

Figure 4: Substation actual annual load profile

1.3.2. Load Duration Curve

The load duration curve for CRAI over the 2023/24 and 2024/25 financial years is shown in Figure 5.

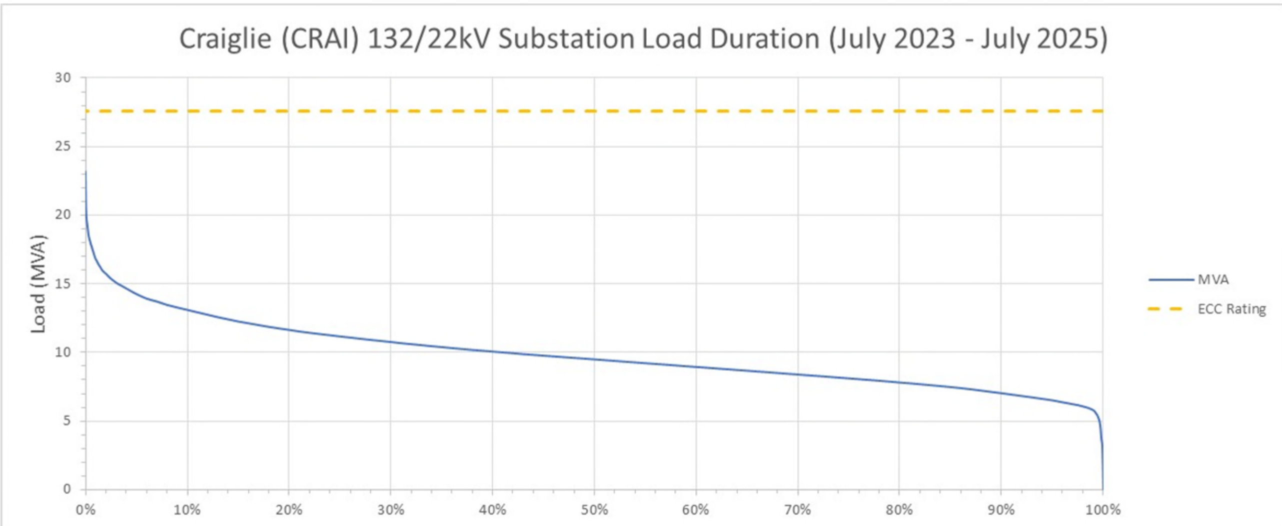

Figure 5: Substation load duration curve

1.3.3. Average Peak Day Load Profile (Summer)

The daily load profile for an average peak day during Summer is illustrated below in Figure 6. It can be noted that the Summer peak loads at CRAI are historically experienced in the late afternoon and evening.

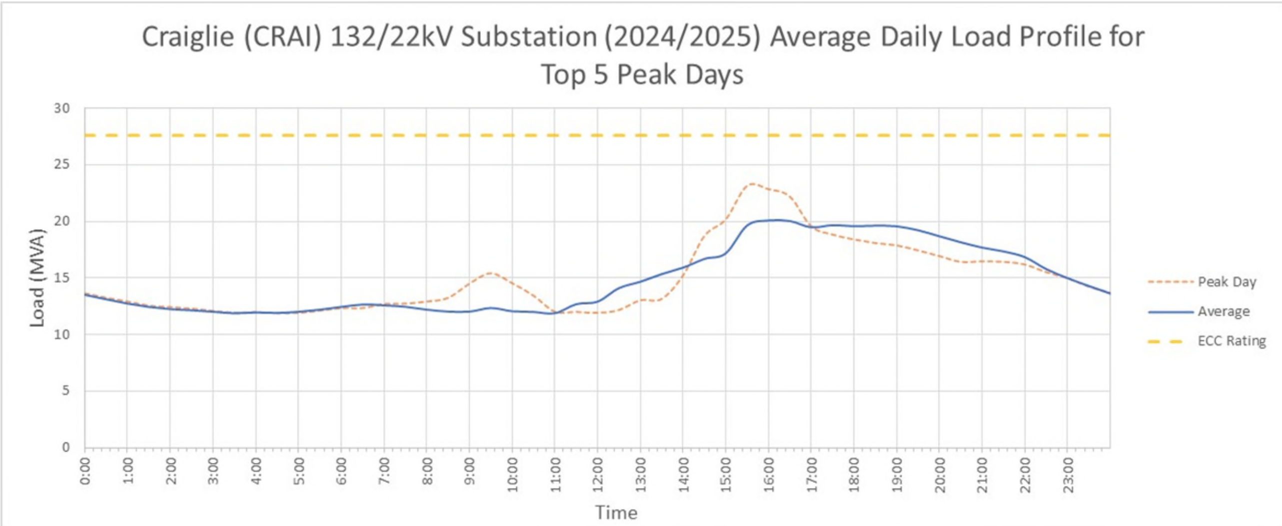

Figure 6: Substation average peak day load profile (summer)

1.3.4. Base Case Load Forecast

The 10 PoE (10% probability of exceedance) and 50 PoE (50% probability of exceedance) load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past six years has also been included in the graph.

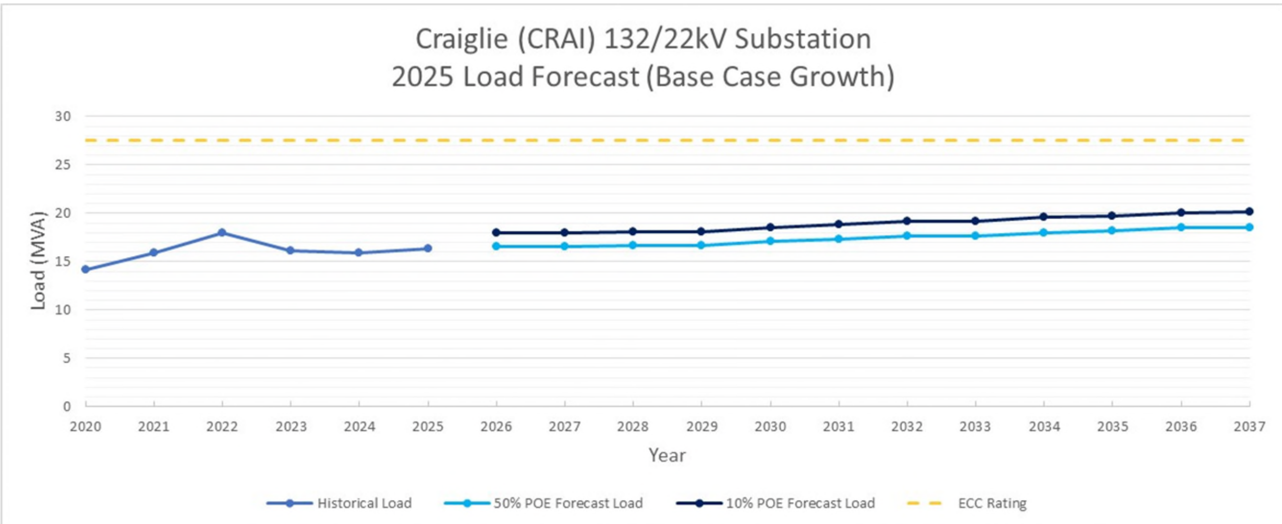

Figure 7: Substation base case load forecast

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 over the next 10 years.

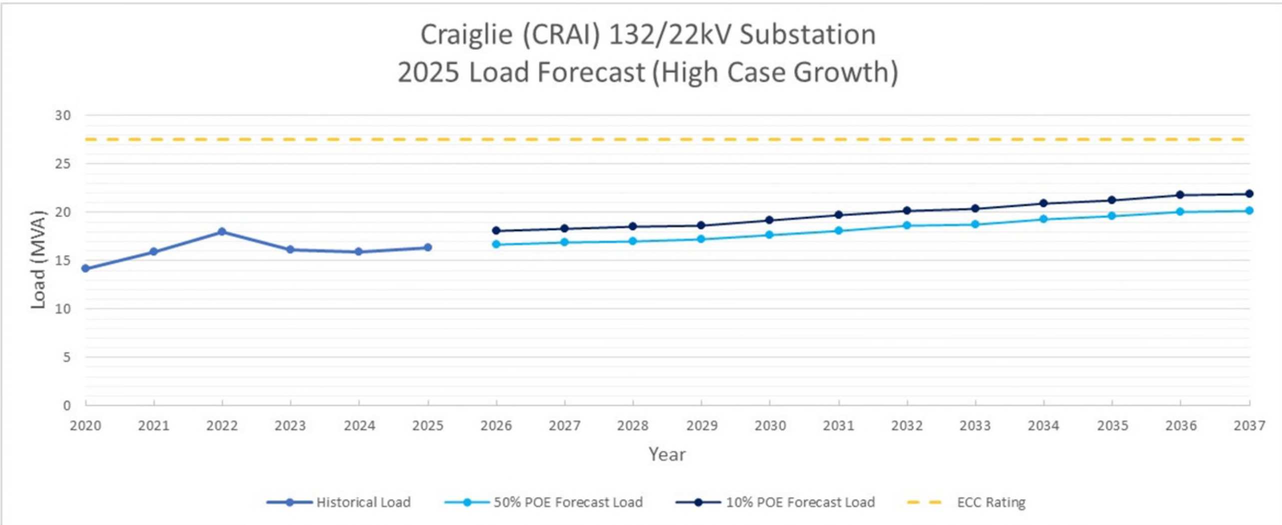

Figure 8: Substation high growth load forecast

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 remain relatively steady over the next 10 years.

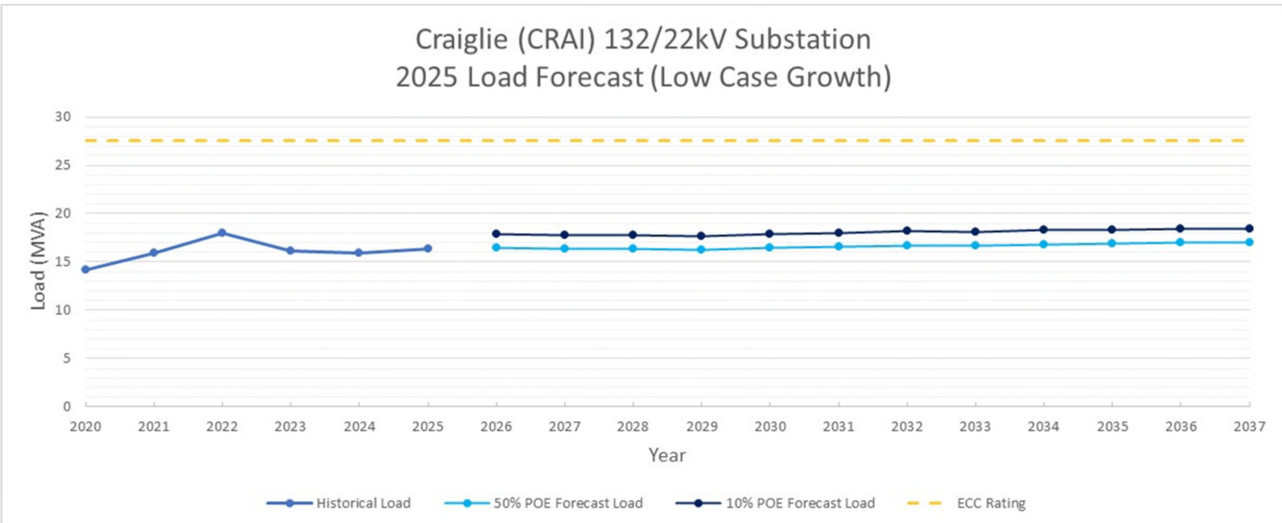

Figure 9: Substation low growth load forecast

1.3.7. Minimum Demand Forecast

The minimum demand forecast at CRAI with the impact of connected solar PV systems is decreasing as illustrated in Figure 10. The reverse power flow capacity of CRAI is limited by the single switching resistor type tap changer of the transformer with a system normal rating of 4.2MVA with both transformers in service and a contingent rating of 2.1MVA with one of the transformers out of service. With each of the solar PV uptake scenarios, the minimum demand forecast is showing reverse power flows at CRAI that are forecast to exceed the reverse power flow capacity over the next 10 years.

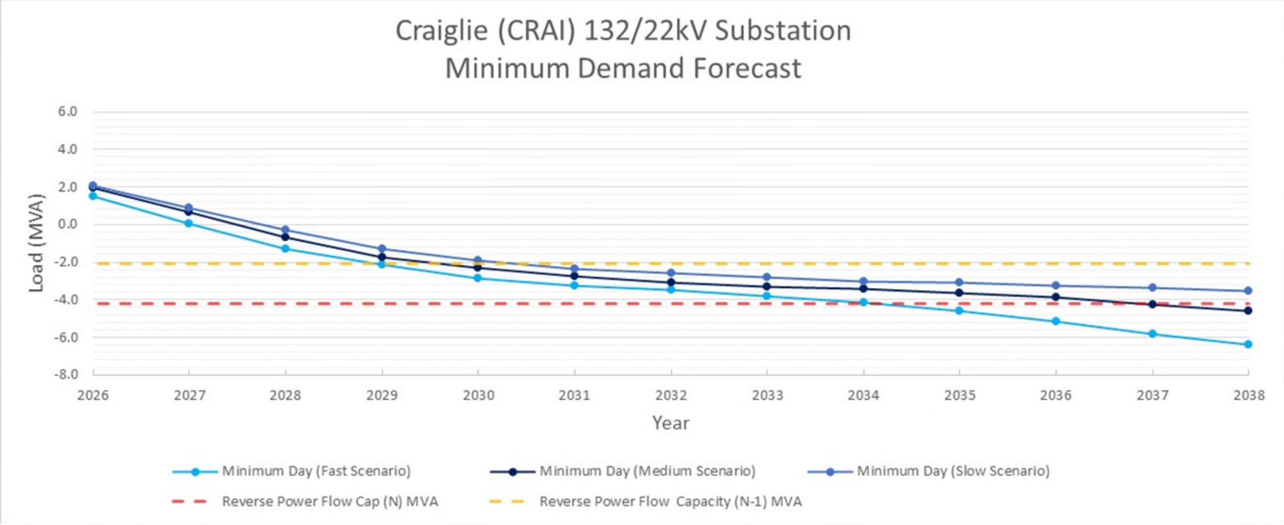

Figure 10: Minimum Demand forecast

2. IDENTIFIED NEED

2.1. Description of the Identified Need

2.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20MVA English Electric 132/22kV transformers (YOM 1967) and protection relays at CRAI are reaching end of life. The ongoing operation of these assets beyond their estimated retirement date presents significant safety, environmental and customer reliability risks.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the substation. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation. 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.

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 CRAI. The CRAI transformers also have a 2.1MVA reverse power flow limitation due to their single switching resistor type tap changers, which could limit export from future customer PV systems.

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.

[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

[6] Ergon Energy Distribution Authority:
Section 7 - Guaranteed Service Levels
Section 8 - Distribution Network Planning
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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

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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 at section 5.

3.2. Network Options Identified

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

3.2.1. Option A: Replace both 132/22kV transformers and protection relays at CRAI in 2027

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2027 and would address the identified need by replacing deteriorated assets at CRAI ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves the replacement of the 132/22kV transformers and protection relays and installation of a 132kV dead tank circuit breaker at CRAI in 2027 in order to address the identified need.

Due to the scope of works being entirely contained within the existing CRAI site, 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 $10.3 million, which has been factored into the NPV to be incurred in 2027.

The estimated capital cost comprises 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).
- overheads that can be directly apportioned to the credible option.
- labour and labour related costs that can be directly attributed to providing the option.
- costs of complying with relevant laws, regulations and administrative requirements; and
- costs unique to asset replacement projects or programs.

The estimated increase in planned annual operating and maintenance costs, compared to the counterfactual, for this option is $3.5 thousand, which has been factored into the NPV.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 11.

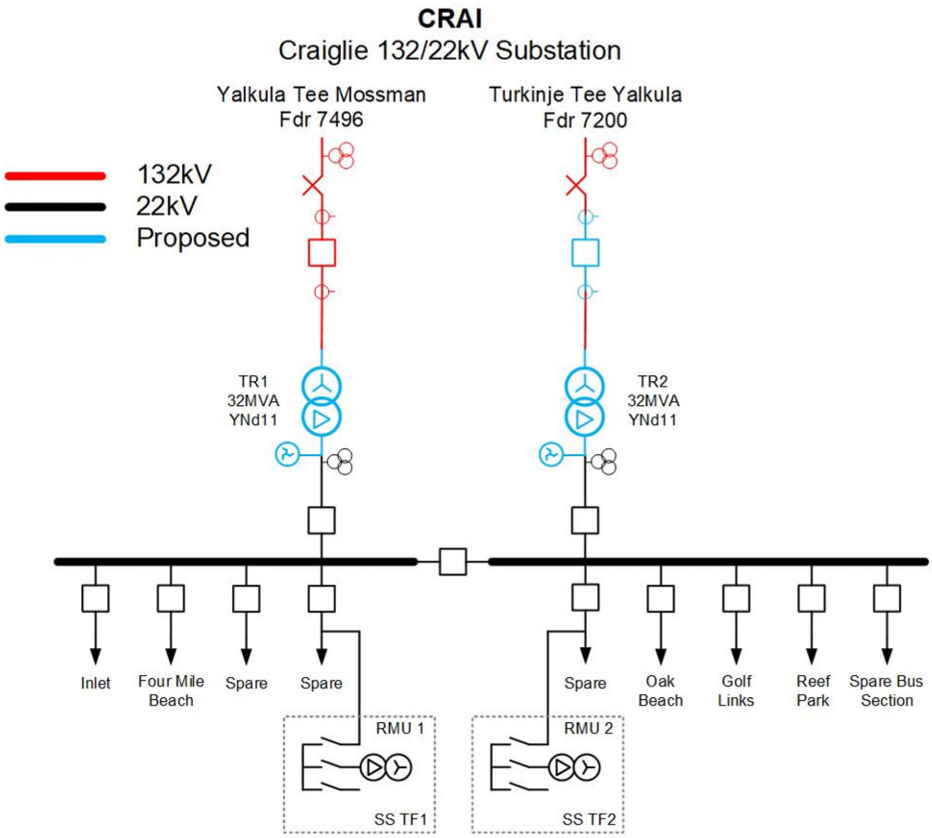

Figure 11: Option A proposed network arrangement (schematic view)

3.3. Preferred Network Option

Ergon Energy's preferred option is Option A, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at CRAI 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 $10.3 million. The estimated increase in planned annual operating and maintenance costs, compared to the counterfactual, for this option is $3.5 thousand. The estimated project delivery timeframe has design commencing in late-2025 and construction completed by mid-2027.

4. SOCIAL LICENCE AND COMMUNITY ENGAGEMENT

4.1. 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.

4.2. 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.

5. ASSESSMENT OF SAPS AND NON-NETWORK SOLUTIONS

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

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

5.2. 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 CRAI 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.

5.2.1. Network Load Control

The residential customers and commercial load appear to drive the daily peak demand which generally occurs between 4:00pm and 7:00pm.

There are 601 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 360kVA[9] is available.

CRAI does not have remote LC functionality and the Tariff 33 and 31 hot water LC channels are controlled locally at each premise via time clocks on a fixed timetable. Therefore, network load control would not sufficiently address the identified need.

5.3. 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.

5.3.1. 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.

5.3.2. 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.

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

5.3.4. Customer Solar Power Systems

A total of 1052 customers with solar photo voltaic (PV) systems for a connected inverter capacity of 8,797kVA.

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

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The daily peak demand is driven by residential customers and commercial load and the peak generally occurs between 4:00pm and 7:00pm. As such customer solar generation does not coincide with the peak load period.

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

PV systems with BESS present a future portfolio opportunity for potential demand response 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.

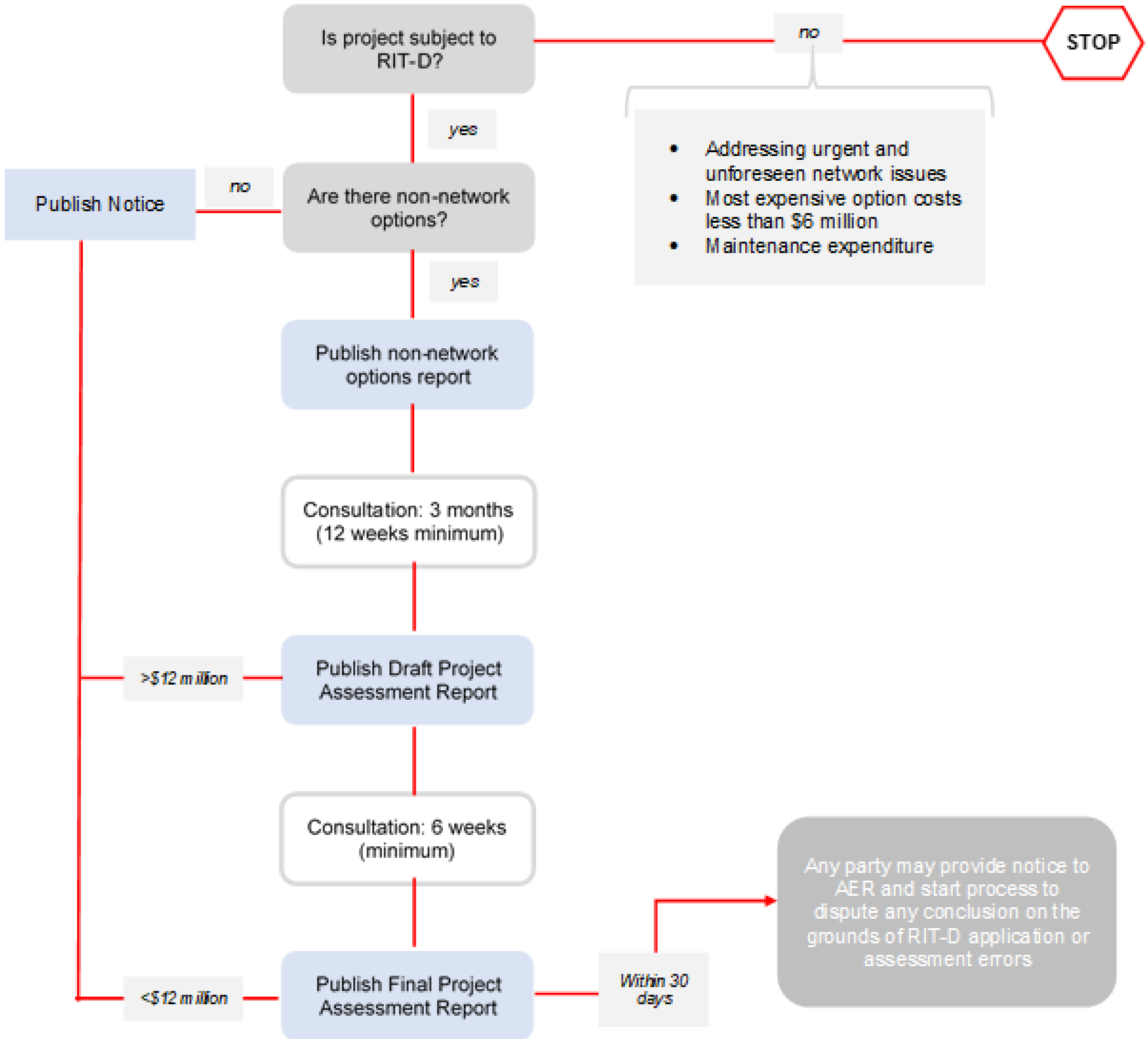
6. CONCLUSION AND NEXT STEPS

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 network Option A, to replace both 132/22kV transformers and protection relays at CRAI in 2027.

This Notice of No Non-Network or SAPS 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.