Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Neil Smith Network Area

Final Project Assessment Report

30 April 2025

ERGON ENERGY NETWORK

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

Neil Smith 66/11kV Substation (NESM) provides electricity supply to approximately 2,348 predominantly residential customers in the Townsville City area, of which 79% are residential and 21% are commercial and industrial. NESM supplies 67.5 GWh of energy annually, with 15.4% of this energy consumed by residential customers.

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20/25MVA English Electric 66/11kV transformers (YOM 1970), the South Wales 11kV switchboard (YOM 1967) and a majority of the protection relays at NESM 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 switchyard. 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 NESM. Ergon Energy has obligations to comply with reliability performance standards specified in its

[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

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

Ergon Energy published a Draft Project Assessment Report for the identified need in the Neil Smith network area on 24 February 2025. No submissions were received by the closing date of 14 April 2025.

Three potentially feasible options have been investigated:

- **Option A:** Replace the 66/11kV transformers and replace the 11kV switchboard in a new building at NESM.
- **Option B:** Establish Townsville Central 66/11kV Substation and de-commission NESM.
- **Option C:** Transfer load from NESM onto adjacent zone substations, temporarily decommission NESM and rebuild NESM after 2035.

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

Ergon Energy's preferred network option to address the identified need is Option A, to replace the 66/11kV transformers and replace the 11kV switchboard in a new control building at NESM.

[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

CONTENTS

1. INTRODUCTION

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

This FPAR represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Neil Smith network area.

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

1.1. Response to the DPAR

Ergon Energy published a Draft Project Assessment Report for the identified need in the Neil Smith network area on 24 February 2025. No submissions were received by the closing date of 14 April 2025.

1.2. Structure of the Report

This report:

- Provides background information on the network limitations of the distribution network supplying the Neil Smith 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.

1.3. Dispute Resolution Process

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

If no formal dispute is raised, Ergon Energy will proceed with the preferred network option, to replace the 66/11kV transformers and replace the 11kV switchboard in a new control building at NESM.

1.4. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Neil Smith 66/11kV Substation (NESM) provides electricity supply to approximately 2,348 predominantly residential customers in the Townsville area, of which 79% are residential and 21% are commercial and industrial. NESM supplies 67.5 GWh of energy annually, with 15.4% 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)

2.2. Existing Supply System

NESM is located in the Townsville City area in North Queensland and is supplied via two incoming 66kV feeders from Townsville Port 66/11kV Substation (TOPO) and T046 Garbutt 132/66kV Substation (GARB).

NESM was established in 1970 according to applicable design and construction standards during that time. NESM consists of 2 x 66/11kV 15/20/25MVA (ON/OB/OFB) power transformers and an indoor 11kV switchboard with 11 outgoing 11kV feeders.

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

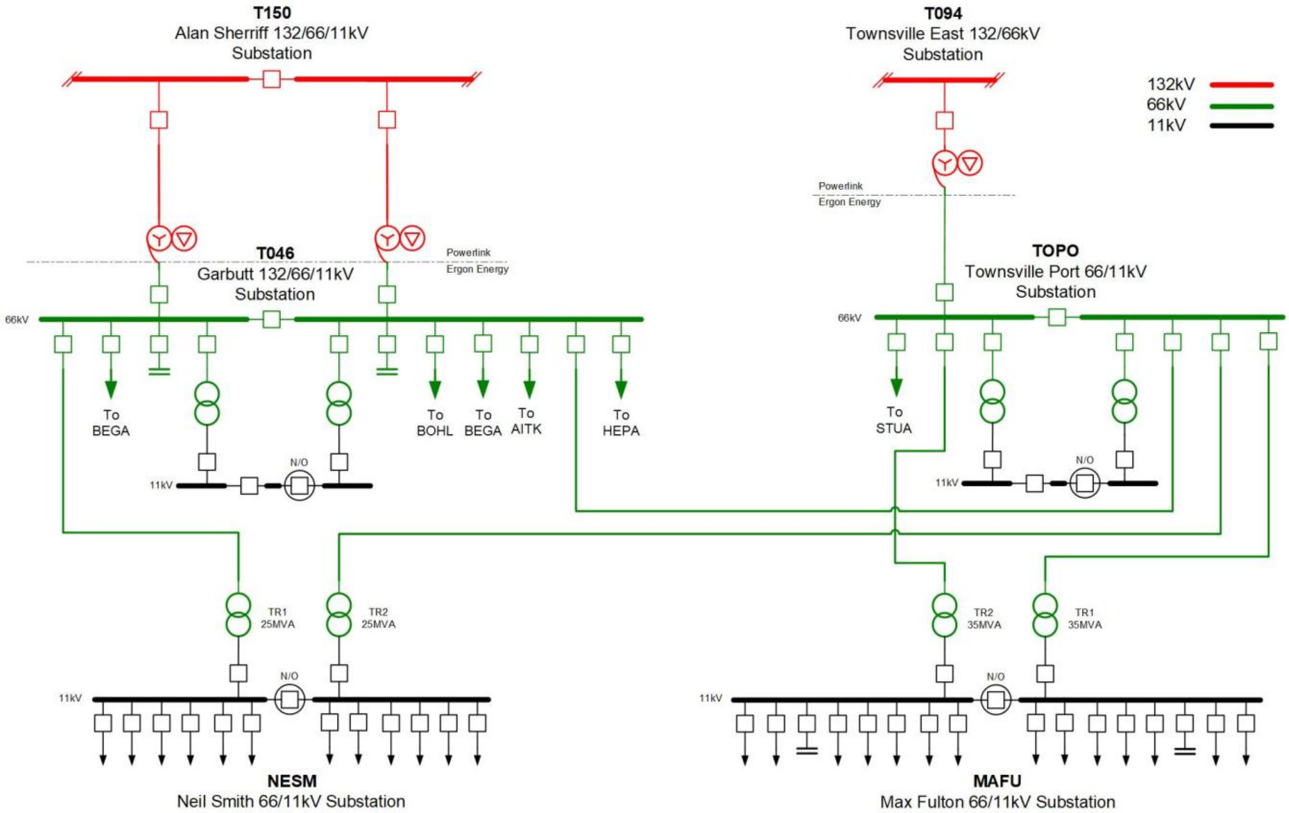

Figure 2: Existing network arrangement (schematic view)

Figure 3: Neil Smith Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at NESM 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.

2.3.1. Full Annual Load Profile

The full annual load profile for NESM over the 2022/23 and 2023/24 financial years is shown in Figure 4.

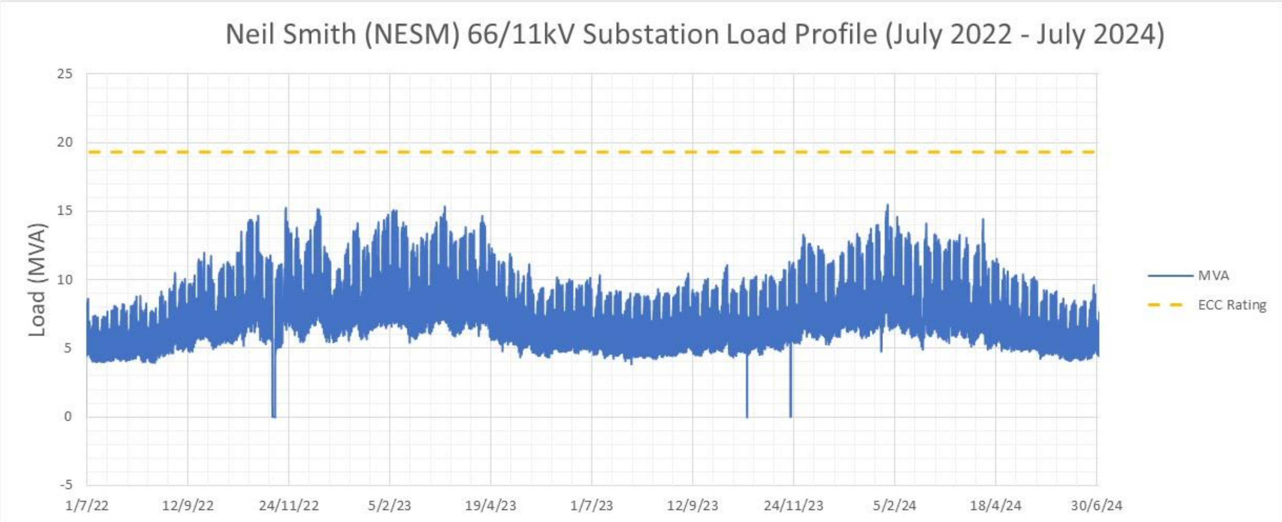

Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for NESM over the 2022/23 and 2023/24 financial years is shown in Figure 5.

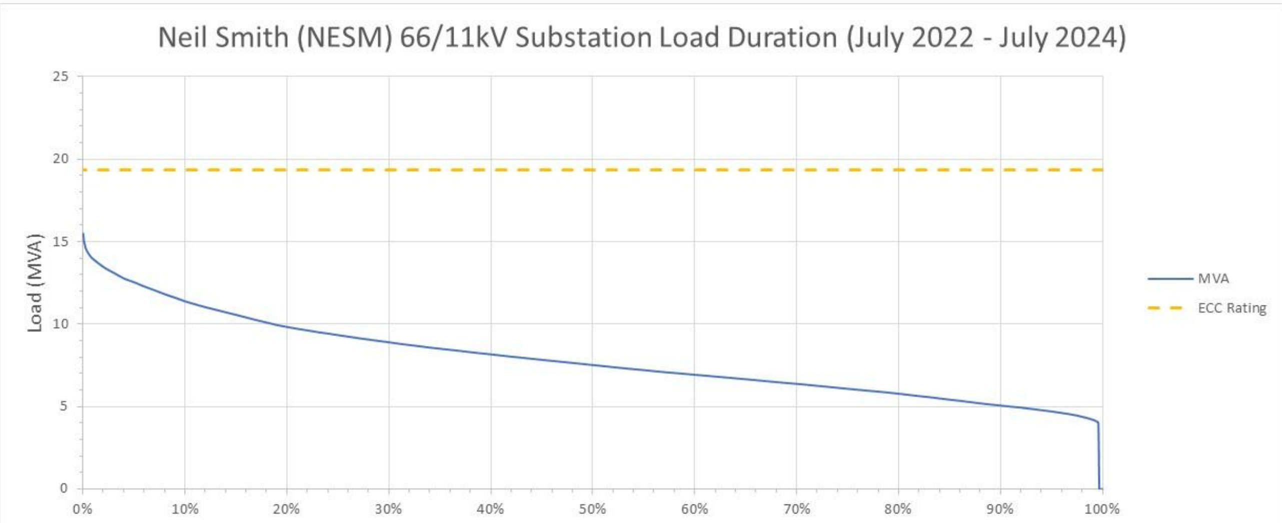

Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday 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 NESM are historically experienced during the day.

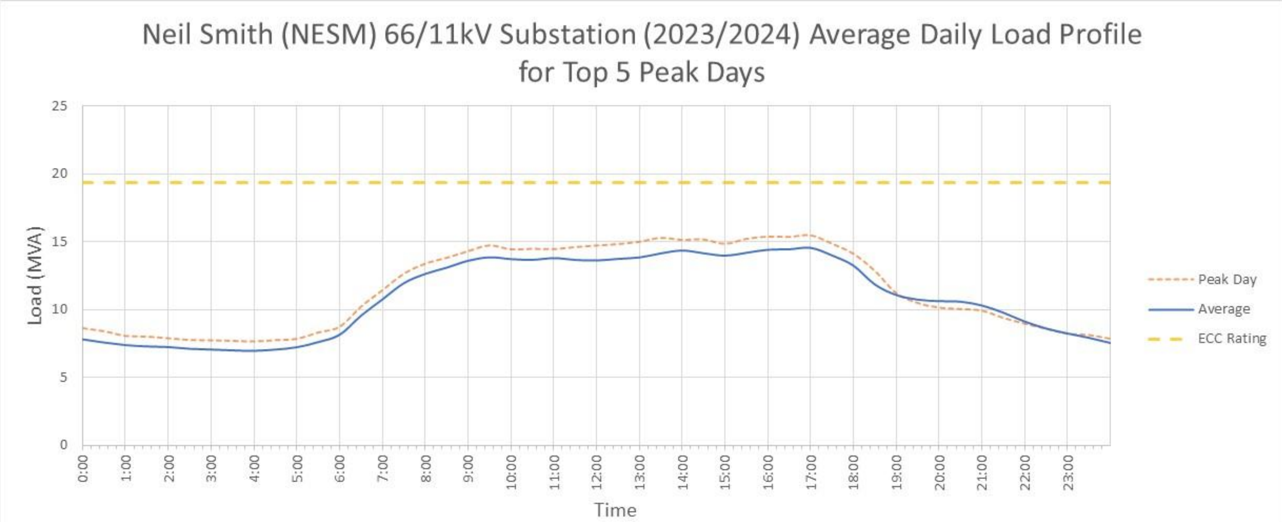

Figure 6: Substation average peak day load profile (Summer)

2.3.4. 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.

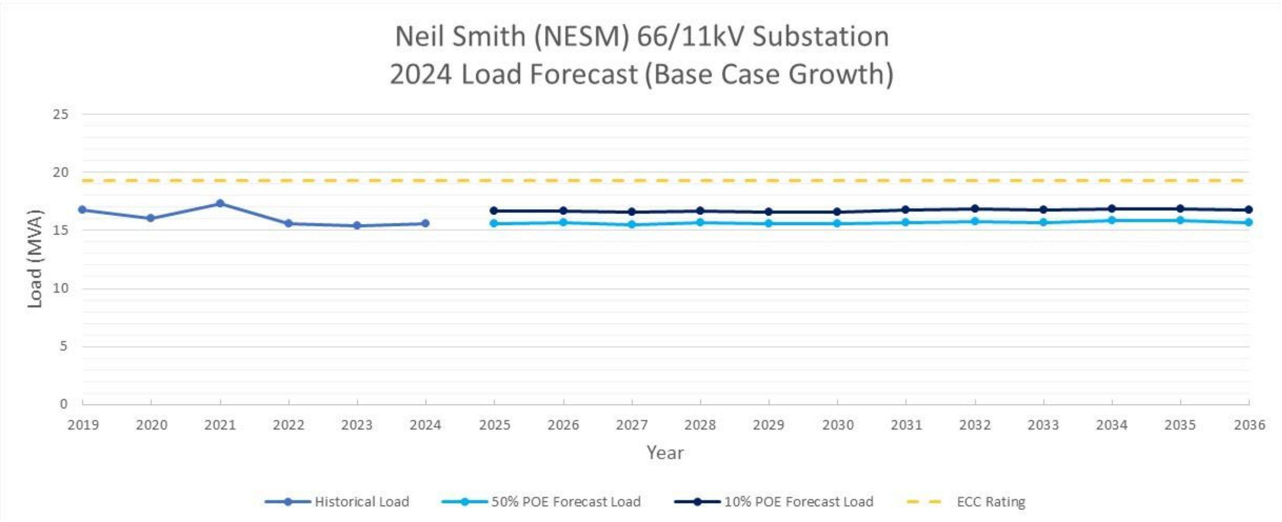

Figure 7: Substation base case load forecast

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 over the next 10 years.

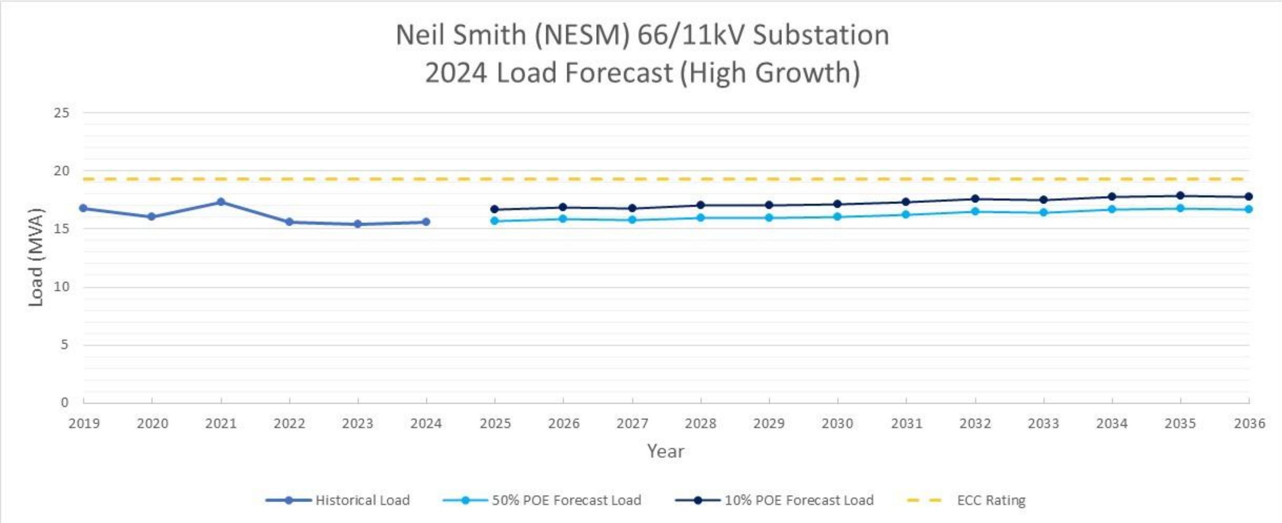

Figure 8: Substation high growth load forecast

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 remain relatively steady over the next 10 years.

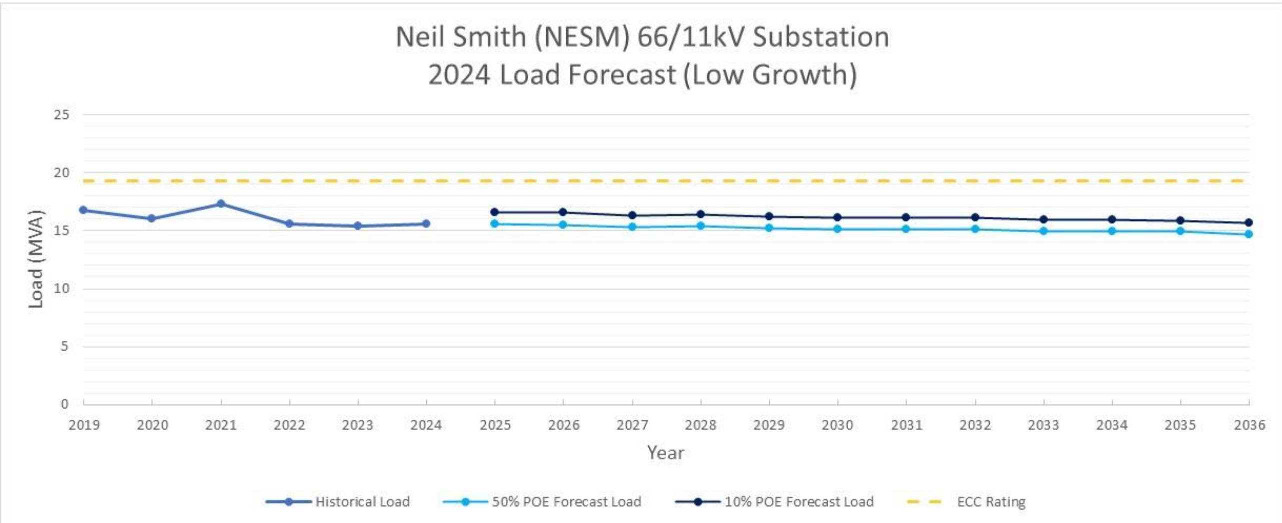

Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

Condition Based Risk Management (CBRM) analysis has identified that the two 15/20/25MVA English Electric 66/11kV transformers (YOM 1970), the South Wales 11kV switchboard (YOM 1967) and a majority of the protection relays at NESM 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 NESM. 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.

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[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
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Section 9 - Minimum Service Standards
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[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

3.2. 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 NESM has considered four primary value streams, *safety, environmental, reliability* and *financial,* as shown in Figure 10 and described in further detail below.

- **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 oil insulated switchgear which could cause severe injuries or a fatality to 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.
- **Environmental:** In the event of a catastrophic failure of one of the transformers, there is a risk of environmental harm due to an oil spill beyond the substation perimeter, which would require clean up and rectification.
- **Reliability:** There is potential unserved energy within the Townsville City network area following an outage at NESM.
- **Financial:** Replacing single assets on failure as individual failed in-service projects has been assumed to incur a 30% increase in cost in comparison to a planned project.

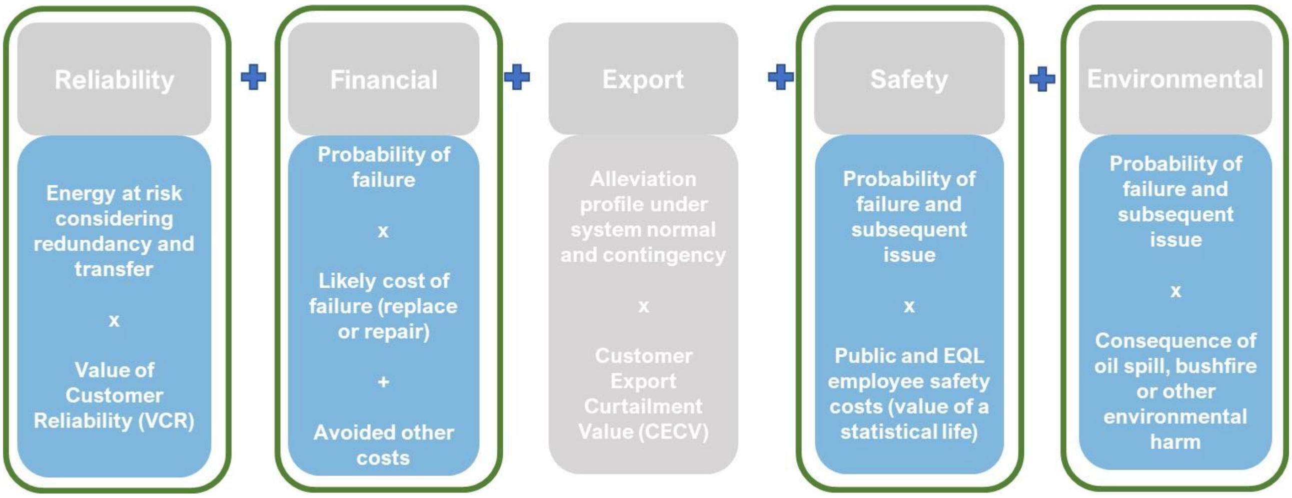


Figure 10 – Value Streams for Investment

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 NESM. Note that Max Fulton 66/11kV Substation (MAFU) has been included in the counterfactual risk quantification as one of the options assessed is to temporarily de-commission NESM and shift load onto MAFU.

In calculating the value streams the following assumptions are used:

- **Forced Outage Rate** – The transformer and circuit breaker outage rates are predicted using a Weibull distribution with a Shape Parameter (β) of 3.6 and a Characteristic Life (η) of 79 for a 66/11kV transformer, and a Shape Parameter (β) of 4 and a Characteristic Life (η) of 75 for 11kV CBs. A flat outage rate of 0.027 has been applied for the first 4 years to capture the increased risk of failure in the first years of a transformer or circuit breakers life.
- **Restoration** – following a transformer outage it has been estimated that the average rectification time would be 2 hours. This considers remote switching time to isolate the transformer and close the normally open bus tie circuit breaker in the event of transformer fault.
- **Restoration** – following an 11kV circuit breaker outage it has been estimated that the average rectification time would be 4 hours. This considers manual switching time in the event of a permanent fault on one of the 11kV circuit breakers.
- **Transfers** – manual transfer capacity of 9.5 MVA via 11kV feeder ties to neighbouring substations.
- **VCR Rate** – a VCR rate of $34.59 / kWh has been used for the 11kV load supplied from NESM and a VCR rate of $34.66 / kWh has been used for the 11kV load supplied from MAFU, with the mix of customers weighted towards domestic and commercial customers. The weighting applied to each customer type is shown in Table 1.
- **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** – Considers forced outage rate of the asset with a conversion factor of 0.1% that a fatality to employee and/or injury to employee will occur.
- **Risk timeframe** – the risks have been quantified over a 60-year period, starting from 2028 to align with the investment year of Option A (see below).

Figure 11 shows the quantified risk per annum for the counter-factual increasing over the 60-year period from 2028 to 2088.

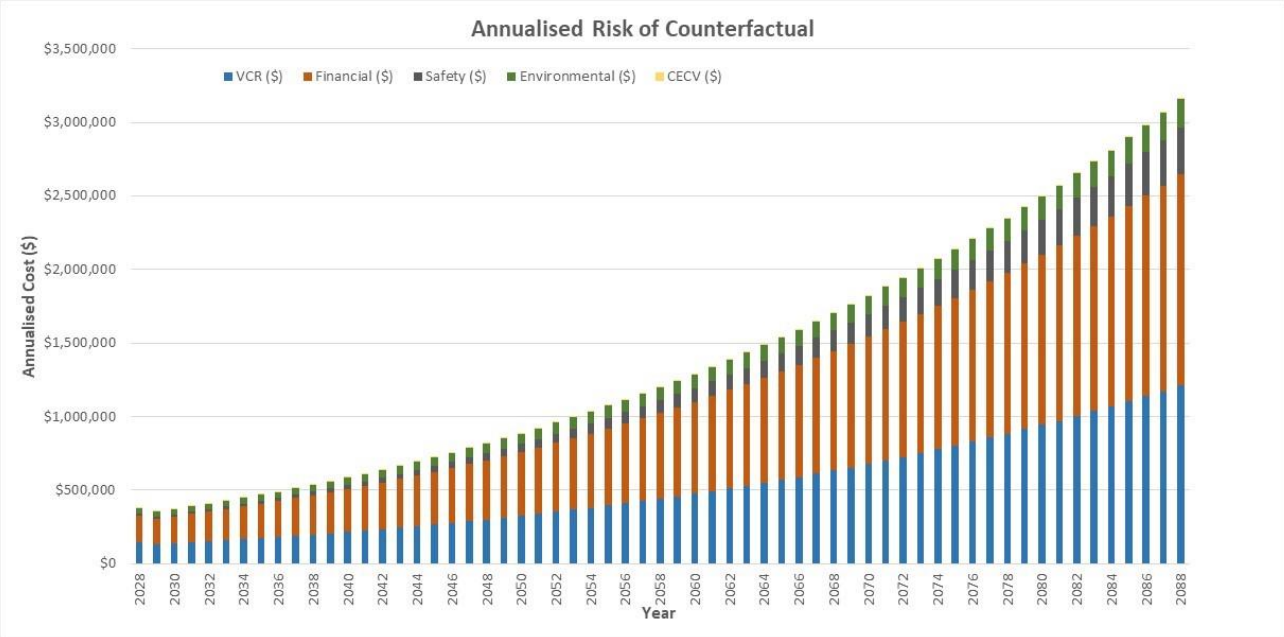


Figure 11: Annualised Risk of Counterfactual

Value of Customer Reliability (VCR) is an economic value applied to customers' unserved energy for any particular year. VCR values represent customers' willingness across the National Electricity Market (NEM) to pay for reliable electricity supply. The VCR is used for estimating market benefits that relate to reliability, such as changes in involuntary and voluntary load curtailment.

The VCR calculated for this analysis for the customers supplied from NESM and MAFU 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)
NESM 11kV Load	Residential (Climate Zone 1)	10,379,624	$35.69
	Commercial*	56,855,945	$34.39
	Industrial*	349,340	$33.49
	Agriculture*		$22.25
	Average VCR		**$34.59**
MAFU 11kV Load	Residential (Climate Zone 1)	17,977,016	$35.69
	Commercial*	52,220,604	$34.39
	Industrial*	3,588,396	$33.49
	Agriculture*	32,039	$22.25
	Average VCR		**$34.66**

Table 1: AER VCR values for NESM and MAFU

*Business using <10MVA peak demand

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

3.3. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at NESM 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. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

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

4.1.1. Option A: Replace the 66/11kV transformers and replace the 11kV switchboard in a new building at NESM

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2028 and would address the identified need by replacing deteriorated assets at NESM ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves the replacement of the 66/11kV transformers and replacement of the 11kV switchboard in a new control building at NESM in order to address the identified need.

Due to the scope of works being entirely contained within the existing NESM 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 $28.4 million, which has been factored into the NPV to be incurred in 2028.

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

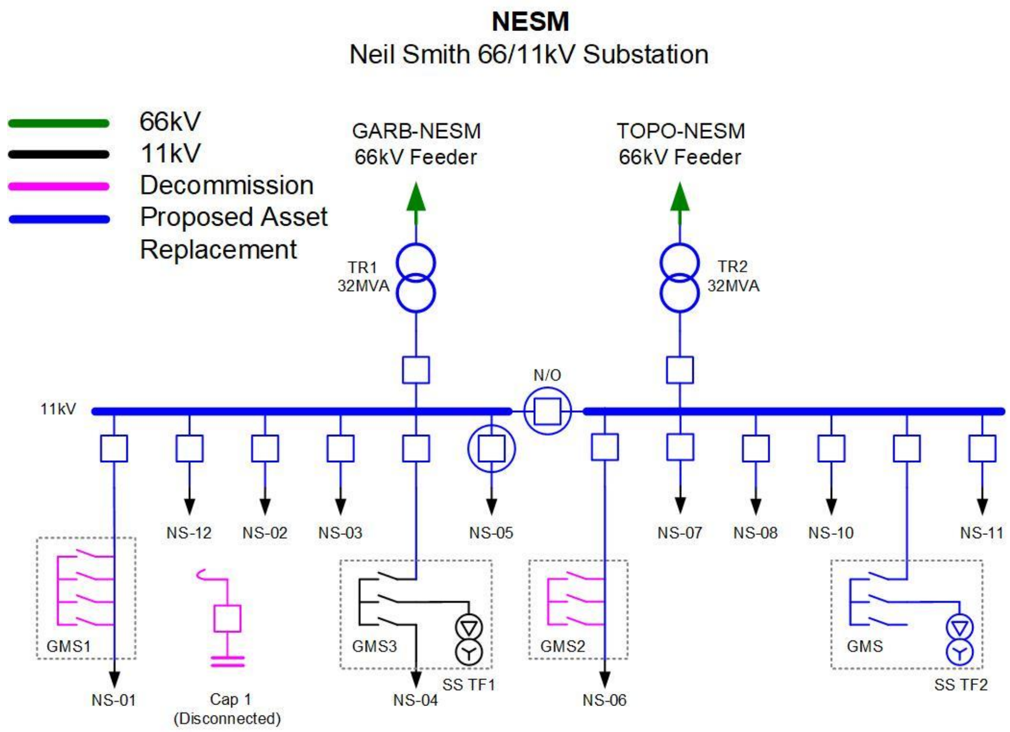


Figure 12: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Establish Townsville Central 66/11kV Substation and de-commission NESM

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2028 and would address the identified need by establishing a new substation to replace the deteriorated assets at NESM ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves establishing a new 66/11kV substation with 2 x 66/11kV transformers on a site owned by Ergon Energy on Sturt Street (Lot 2 on SP229803) including the installation of approximately 1km of 2 x 66kV underground cables to connect to the existing 66kV cables at NESM and the installation of new 11kV feeders from the new substation to tie into the existing NESM 11kV network in order to address the identified need.

Due to the scope of works being entirely contained within the existing substation sites, as well as the expected reliability 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 $62.8 million, which has been factored into the NPV to be incurred in 2028.

A schematic diagram with the proposed network arrangement for Option B is shown in Figure 13.

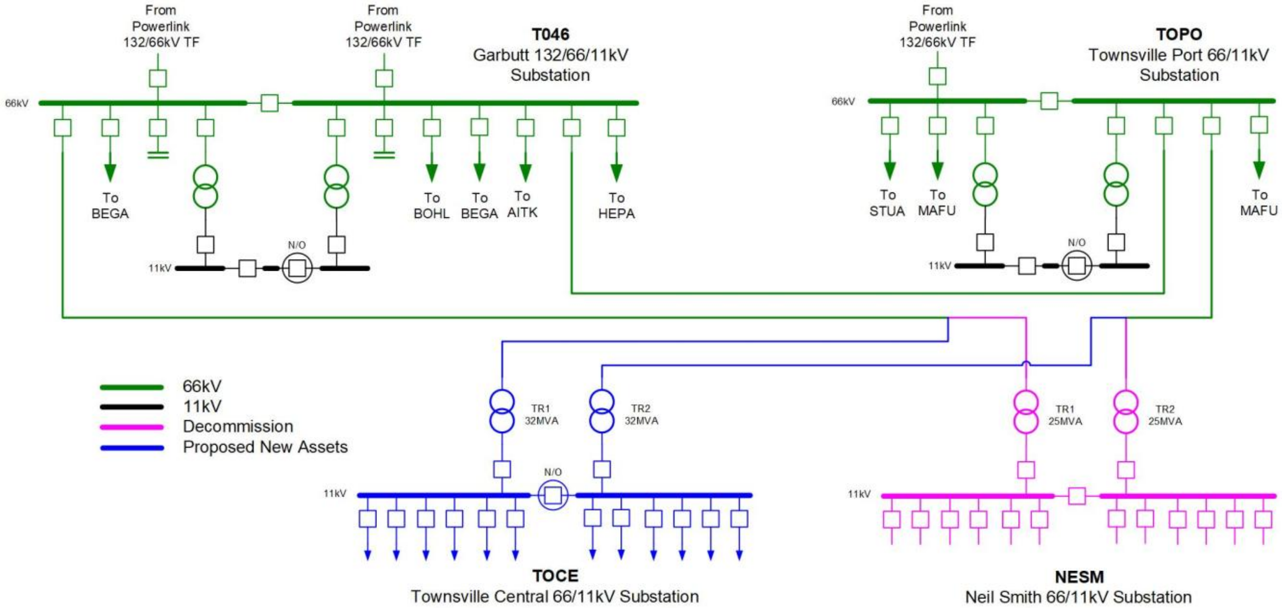


Figure 13: Option B proposed network arrangement (schematic view)

4.1.3. Option C: Transfer load from NESM onto adjacent zone substations, temporarily decommission NESM and rebuild NESM after 2035

This option is commercially and technically feasible, can be implemented in the timeframe identified, mid-2028 and would address the identified need by replacing deteriorated assets at NESM ensuring Ergon Energy continues to adhere to the applicable regulatory instruments.

This option involves decommissioning the 11kV capacitor banks at Max Fulton 66/11kV Substation (MAFU), establishing new 11kV feeders from MAFU to connect into the NESM 11kV network and reconfiguration of the Townsville City 11kV feeders to shift the NESM load onto the adjacent substations. This option also requires uprating the sections of Dog 6/1/.186+7/.062 ACSR/GZ conductor on the MAFU 66kV feeders to allow the conductors to operate up to 75degC. NESM substation would initially be decommissioned, aged plant removed from the site and the NESM 66kV feeders connected using the tie point near Dean Street carpark to form a second GARB-TOPO feeder. NESM would then be rebuilt on the existing site when the Townsville City load can no longer be supplied from the adjacent substation 11kV feeders.

Due to the scope of works being entirely contained within the existing substation sites, 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 stage 1 for this option is $10.8 million, which has been factored into the NPV to be incurred in 2028. The stage 2 estimated capital cost of $27.4 million to rebuild NESM has been factored into NPV calculations to be incurred in 2038.

A schematic diagram of the proposed network arrangement for Option C is shown in Figure 14.

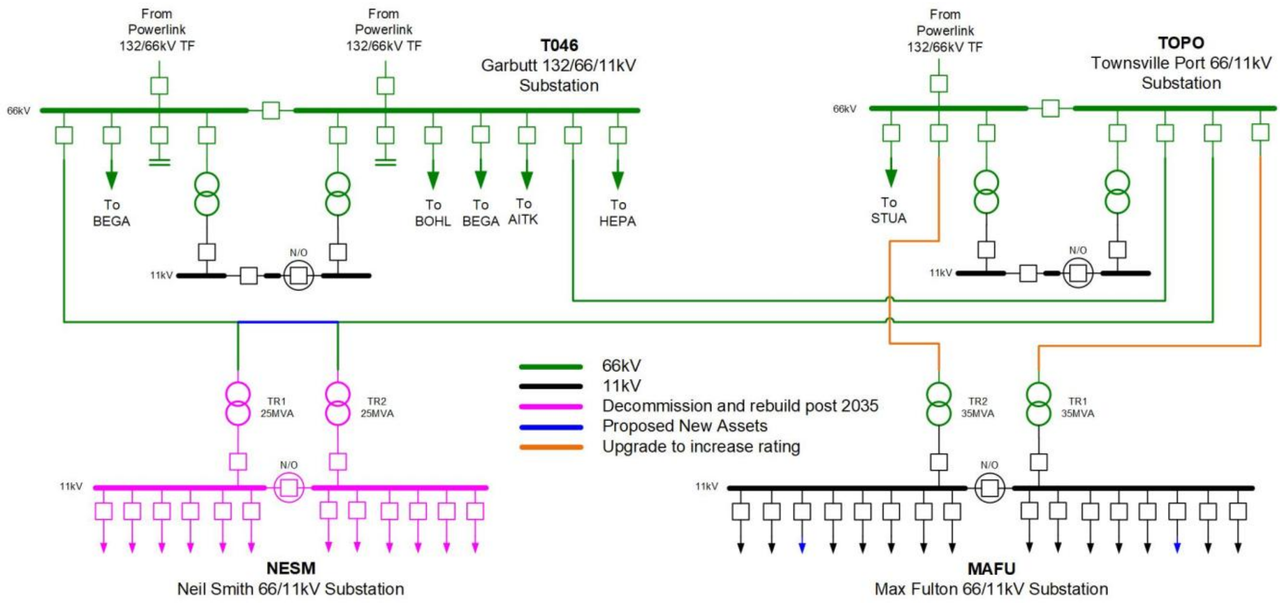


Figure 14: Option C proposed network arrangement – Stage 1 (schematic view)

4.2. Assessment of SAPS and Non-Network Solutions

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

4.2.1. Consideration of SAPS Options

Ergon Energy considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Townsville City 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.

4.2.2. Demand Management (Demand Reduction)

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

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

The DEM team has completed a review of the NESM 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.

Network Load Control

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

There are 435 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 261kVA[9] is available.

NESM LC signals are controlled from T046 Garbutt 132/66kV Substation (GARB). The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable) and the current control strategy only calls LC when the T046 Garbutt 132/66kV Substation 66kV load exceeds 91MW or the T092 Dan Gleeson 132/66kV Substation 66kV load exceeds 110MW or the Stuart Substation 66kV load exceeds 100MW. This strategy does not directly address demand peaks experienced at NESM. Tariff 33 air-conditioning channels are

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

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

4.2.3. Demand Response

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

Customer Call Off Load (COL)

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

Customer Embedded Generation (CEG)

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

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

Large-Scale Customer Generation (LSG)

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

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

Customer Solar Power Systems

A total of 238 customers with solar photo voltaic (PV) systems for a connected inverter capacity of 3,255kVA.

The daily peak demand is driven by residential customers and commercial load and the peak generally occurs between 9:00am and 6:00pm. As such customer solar generation coincides 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.

4.2.4. SAPS and Non-Network Solution Summary

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

4.3. Preferred Option

Ergon Energy's preferred option is Option A, to replace the 66/11kV transformers and replace the 11kV switchboard in a new control building at NESM.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at NESM 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 $28.4 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in early-2026 and construction completed by May 2028.

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

On 24 February 2025, Ergon Energy published the Draft Project Assessment Report providing details on the identified need in the Neil Smith network area. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the identified need.

In response to the Draft Project Assessment Report, Ergon Energy received no submissions by the closing date of 14 April 2025.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the NEM.

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

6.1. Classes of Market Benefits Considered and Quantified

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

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

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

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required, assuming the credible option is completed, multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Ergon Energy has applied a VCR estimate of $34.59/kWh for the NESM 11kV load and $34.66 for the MAFU 11kV load, which has been derived from the AER 2024 Value of Customer Reliability (VCR) values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

Customer export curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to 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 NESM supply area.

6.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Differences in timing of expenditure
- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Australia's greenhouse gas emissions
- Option value
- Costs Associated with Social Licence Activities

6.2.1. Changes in Voluntary Load Curtailment

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

6.2.2. Changes in Costs to Other Parties

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

6.2.3. Differences in Timing of Expenditure

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

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

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

6.2.5. Changes in Electrical Energy Losses

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

6.2.6. Changes in Australia's Greenhouse Gas Emissions

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

6.2.7. Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[10].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

6.2.8. Costs Associated with Social Licence Activities

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

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

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The RIT-D requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the NEM.

Accordingly, a base case NPV comparison of each credible option has been undertaken. A sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered.

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

7.2. Key Variables and Assumptions

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

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

Table 2 outlines the major sensitivities analysed within the Monte-Carlo analysis which was undertaken to assess the sensitivity to a change in parameters of the NPV model.

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

Table 2: Economic parameters and sensitivity analysis factors

7.3. Scenarios Adopted for Sensitivity Testing

A sensitivity analysis was conducted on the base case to establish the option that remained the lowest cost option in the scenarios considered. In this instance, the scenarios that have been considered are:

- **Medium demand** – under this scenario the existing load remains around the same as it currently is. This is consistent with the base case load forecast.

7.4. Net Present Value (NPV) Results

An overview of the base case NPV results are provided in Table 3.

Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
A	Replace the 66/11kV transformers and replace the 11kV switchboard in a new building at NESM	1	-$18,038,000	-$25,480,000	-$9,500,000	$16,943,000
B	Establish Townsville Central 66/11kV Substation and de-commission NESM	3	-$60,478,000	-$56,232,000	-$21,370,000	$17,123,000
C	Transfer load from NESM onto adjacent zone substations, temporarily decommission NESM and rebuild NESM after 2035	2	-$20,793,000	-$26,465,000	-$9,690,000	$15,362,000

Table 3: Base case NPV ranking table

A sensitivity analysis was conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered. Table 4 provides the results of the WACC sensitivity analysis.

Option Number	Option Name	Rank	Net NPV (2.5% WACC)	Net NPV (4.5% WACC)
A	Replace the 66/11kV transformers and replace the 11kV switchboard in a new building at NESM	1	-$14,076,000	-$20,300,000
B	Establish Townsville Central 66/11kV Substation and de-commission NESM	3	-$60,255,000	-$59,789,000
C	Transfer load from NESM onto adjacent zone substations, temporarily decommission NESM and rebuild NESM after 2035	2	-$19,656,000	-$20,770,000

Table 4: Scenario Analysis – WACC sensitivity

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations of all the variables. Table 5 shows the average NPV cost of all the simulations.

Option Number	Option Name	Average NPV	Maximum NPV	Minimum NPV
A	Replace the 66/11kV transformers and replace the 11kV switchboard in a new building at NESM	-$17,924,000	-$8,676,000	-$27,358,000
B	Establish Townsville Central 66/11kV Substation and de-commission NESM	-$60,209,000	-$41,008,000	-$79,351,000
C	Transfer load from NESM onto adjacent zone substations, temporarily decommission NESM and rebuild NESM after 2035	-$20,634,000	-$13,932,000	-$27,621,000

Table 5: Monte Carlo Analysis for Base Case Forecast

Option A also has the lowest average cost and is the most economical in 94.2% of cases in the Monte-Carlo simulations.

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

8. CONCLUSION

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

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

8.1. Preferred Option

Ergon Energy's preferred option is Option A, to replace the 66/11kV transformers and replace the 11kV switchboard in a new control building at NESM.

Upon completion of these works the identified need would be addressed by replacing deteriorated assets at NESM 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 $28.4 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The estimated project delivery timeframe has design commencing in early-2026 and construction completed by May 2028.

8.2. Satisfaction of RIT-D

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

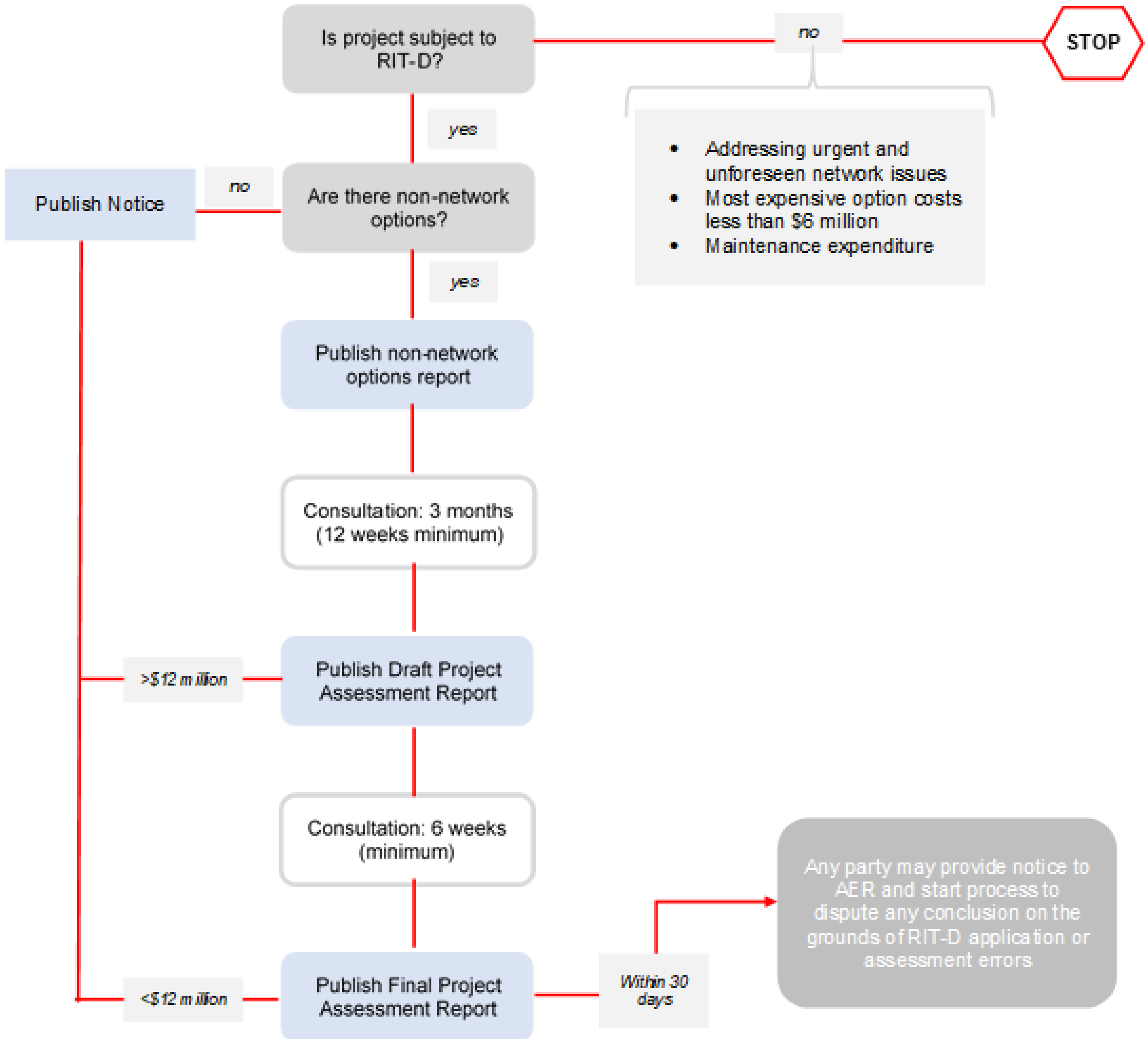
This statement is made on the basis of the detailed analysis set out in this report. The preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	5
(4) a description of each credible option assessed	4
(5) where a *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	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4 & 7
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	6.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7
(10) the identification of the proposed preferred option	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (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	8.1 & 8.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.4

APPENDIX A – THE RIT-D PROCESS



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