Regulatory Investment Test for Distribution (RIT-D)

North Street Zone Substation Network Limitation

Final Project Assessment Report

17 April 2023

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

North Street 33/11kV (NOST) zone substation is located on the northern side of Toowoomba. The substation supplies approximately 7,300 residential, industrial and commercial customers with a peak load of 21.9MVA.

NOST was originally established as a 33/6.6kV substation in 1942 and built to standards applicable at the time. Over the period 1962 to 1966 it was converted to 33/11kV with three 5MVA power transformers installed. During 1984 the 33kV yard was reconstructed and the three power transformers were upgraded to 10MVA units.

There are currently numerous plant having mis-matched age and condition profiles. Notably four 11kV circuit-breakers (CBs), nine 11kV isolators and sixteen protection relays have presently reached end of life based on asset modelling. Twelve 33kV rotary isolators have an expected retirement year of 2044 and the three 33/11kV transformers have an estimated retirement year of 2035.

The existing control building has been deemed to be structurally unsound due to internal structural wall being removed some time in the past. Temporary reinforcement of the building was undertaken in 2022 to enable it to remain in service until such time as a new building can be established.

The ongoing operation of these assets beyond their estimated retirement date presents a significant risk to safety and customer reliability. The purpose of this project is to remove the asset condition limitations at NOST in order to maintain continuity of supply to its customers and to reduce the safety risks SFAIRP (So Far As Is Reasonably Practicable).

A new $1.3 billion Toowoomba Hospital was announced as part of the 2022/23 Queensland State Budget. It is planned to be opening in the second half of 2027 and to be supplied at 11kV from NOST. Any credible option to address the asset limitations must be capable of meeting Safety Net service standards considering the new hospital loads as well as the natural growth in the NOST supply area.

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 NOST 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 above described network constraint on 3 March 2023. No submissions were received by the closing date of 14 April 2023.

Two potentially feasible options have been investigated:

- **Option 1:** NOST full substation rebuild. Rebuild outdoor 11kV and 33kV yards in situ.
- **Option 2:** NOST full substation rebuild. Replace outdoor 11kV and 33kV yards with indoor switchboards.

This Final Project Assessment Report (FPAR), where Ergon Energy provides both technical and economic information about possible solutions, has been prepared in accordance with the requirements of clause 5.17.4(o) of the NER.

Ergon Energy's preferred solution to address the identified need is Option 2: NOST full substation rebuild. Replace outdoor 11kV and 33kV yards with indoor switchboards.

CONTENTS

1. INTRODUCTION

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

This report 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 NOST 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 NOST network area on the 3 March 2023. No submissions were received by the closing date of the 14 April 2023.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the NOST 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.
- 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(a) of the NER, Registered Participants or Interested Parties 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. Accordingly, Registered Participants and Interested Parties who wish to dispute the conclusions outlined in this report based on a manifest error in the calculations or application of the RIT-D must do so within 30 days of the publication date of this report. 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 option to fully rebuild NOST including replacing the outdoor 11kV and 33kV yards with indoor switchboards.

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

North Street 33/11kV zone substation (NOST) is located on the northern side of Toowoomba. Figure 1 shows a geographical view of the Toowoomba transmission and sub-transmission networks.

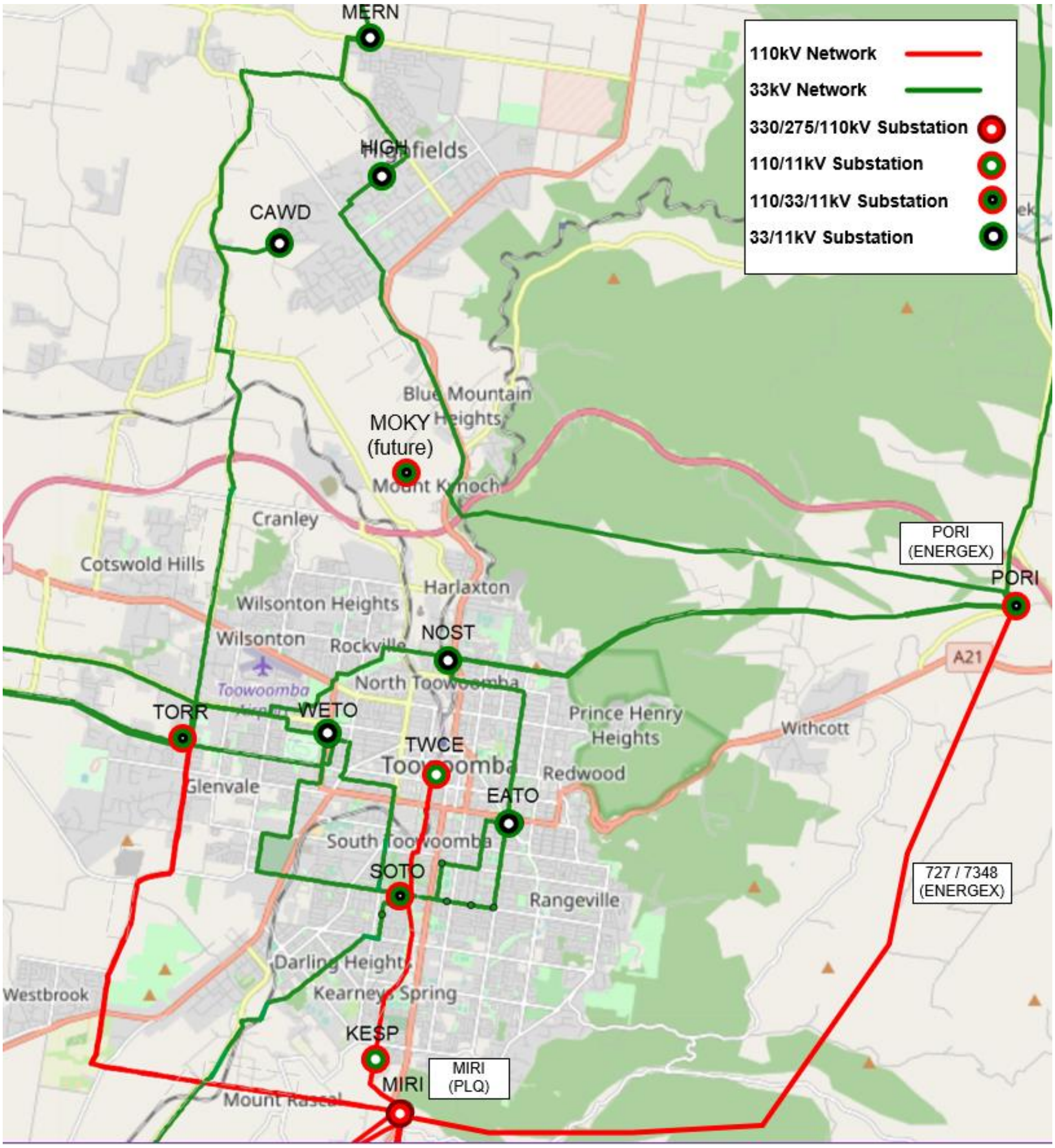


Figure 1: Geographic view of the Toowoomba transmission and sub-transmission networks.

2.2. Existing Supply System

NOST is normally supplied from Torrington BSP (TORR) via Boundary St 33kV feeder and the backup supply comes from Postman's Ridge BSP (PORI) via North St 33kV feeder. Historically an additional supply was available from South Toowoomba BSP (SOTO) via Jellicoe St 33kV feeder, however the Jellicoe St feeder bay at NOST has been decommissioned and this supply option is no longer available.

The incoming 33kV feeders connect to a three-section 33kV outdoor bus which supply 3 x 10MVA 33/11kV transformers. These supply the outdoor 11kV bus and 9 x 11kV feeder circuit breakers (CBs). The 11kV feeders extend into the north Toowoomba area to bring supply to approximately 7,300 residential, industrial and commercial customers with an existing peak load of 21.9MVA.

A schematic view of NOST and the sub-transmission network arrangement is shown in **Figure 2** and **Figure 3** gives an aerial view of the NOST site.

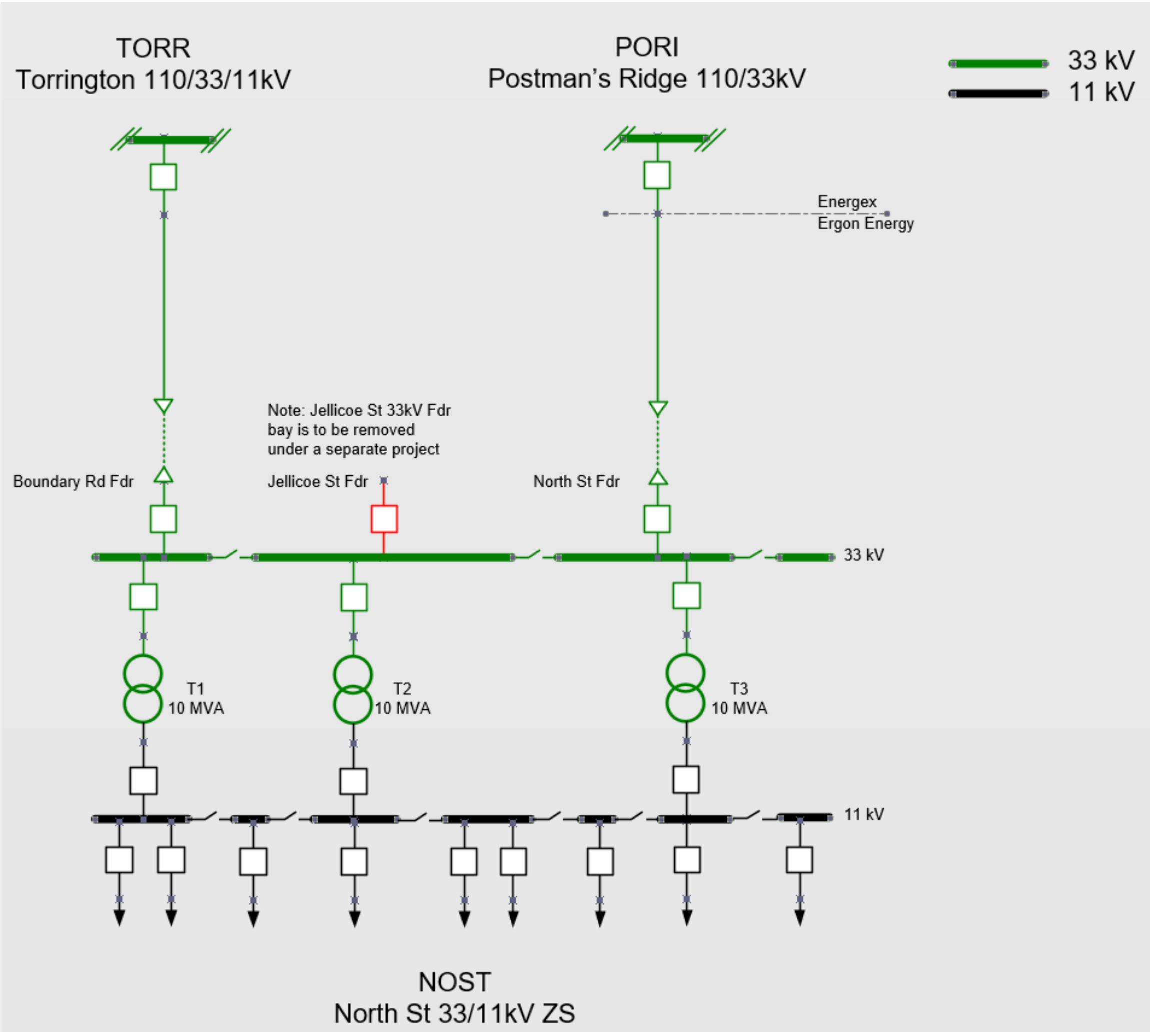


Figure 2: NOST network arrangement (schematic view).

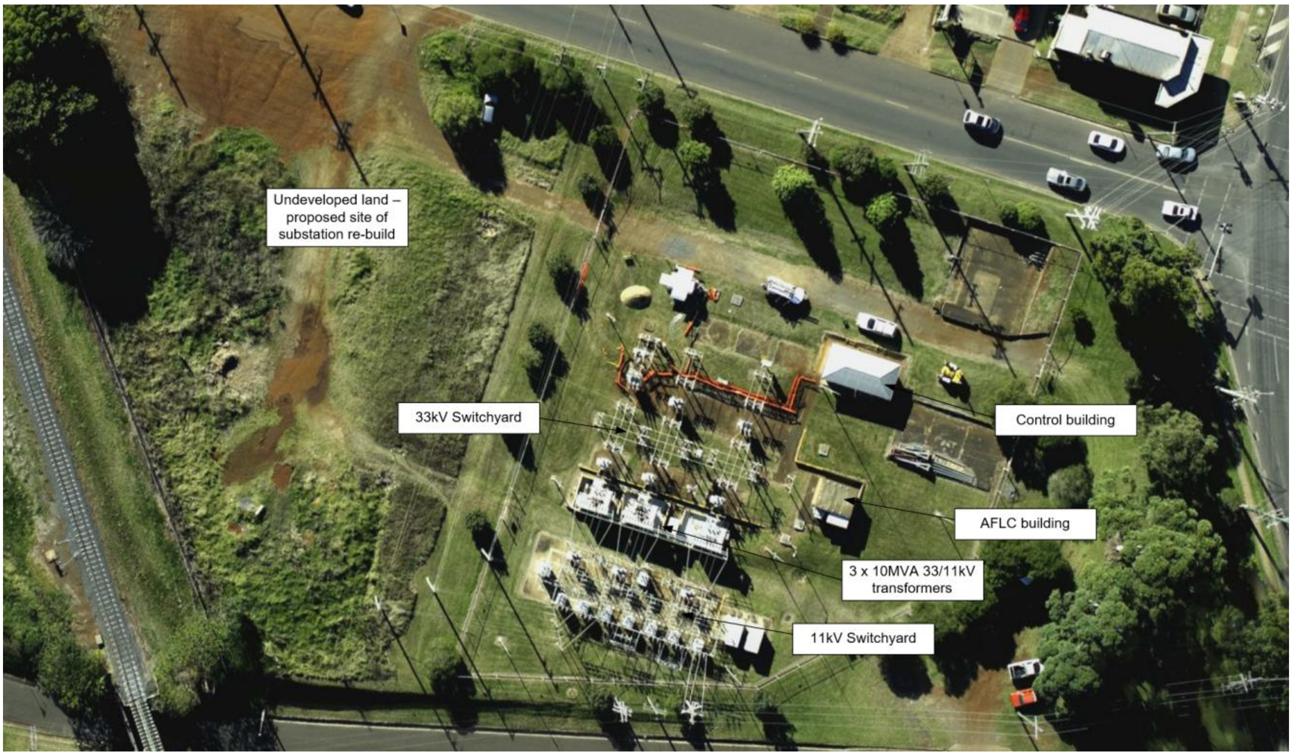


Figure 3: NOST site (aerial view).

2.3. Substation Plant Rating

Substation capacity at NOST is limited by the thermal rating of the three 33/11kV transformers which are shown in **Table 1**. These ratings result in NOST having a Summer N rating of 31.1MVA and N-1 rating of 23.6MVA. In winter, NOST has an N rating of 34.5MVA and N-1 rating of 26.5MVA.

Table 1: NOST transformer rating

Plant number	TX Number	Normal Cyclic Rating		Emergency Cyclic Rating	
		Summer (MVA)	Winter (MVA)	Summer (MVA)	Winter (MVA)
TR92582715	T1	10.37	11.49	11.81	13.24
TR92704911	T2	10.37	11.49	11.81	13.24
TR93075163	T3	10.37	11.49	11.81	13.24

2.4. Load Profiles / Forecasts

2.4.1. Annual Load Profile

The full annual load profile for NOST 33/11kV zone substation for the year 2022 is shown in Figure 4. Historically, peak loading occurs during the winter period however summer peaks can be significant as well. The substation N-1 capacity (26.5MVA Winter, 23.6MVA Summer) is not exceeded at any time during the year.

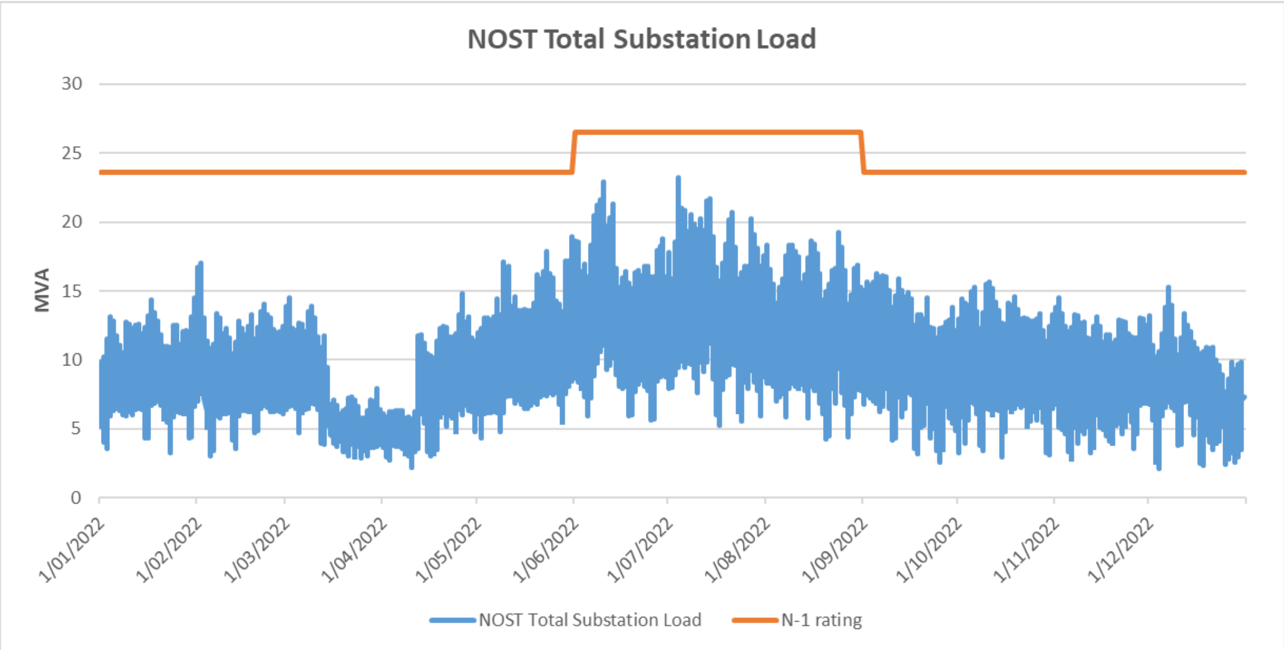


Figure 4: North Street ZS annual load profile (2022).

2.4.2. Load Duration Curve

The load duration curve for the NOST total substation load for 2022 is shown in Figure 5.

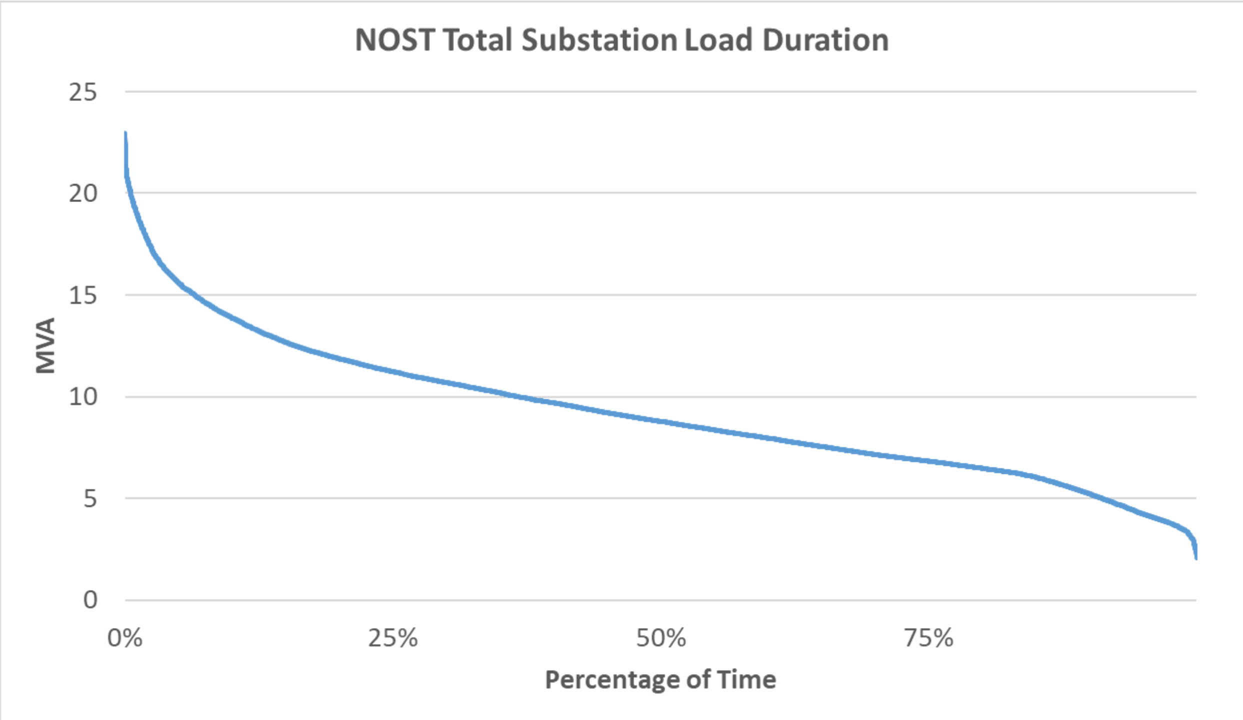


Figure 5: NOST Load Duration (2022)

2.4.3. Seasonal Weekday Load Profiles

The seasonal daily load profiles for the average, maximum and minimum and peak weekdays are illustrated below in Figure 6 and Figure 7. The summer peak loads for NOST are historically experienced in the late afternoon and evening. The winter peak is similarly in the afternoon / evening and shows a more pronounced load increase in the morning.

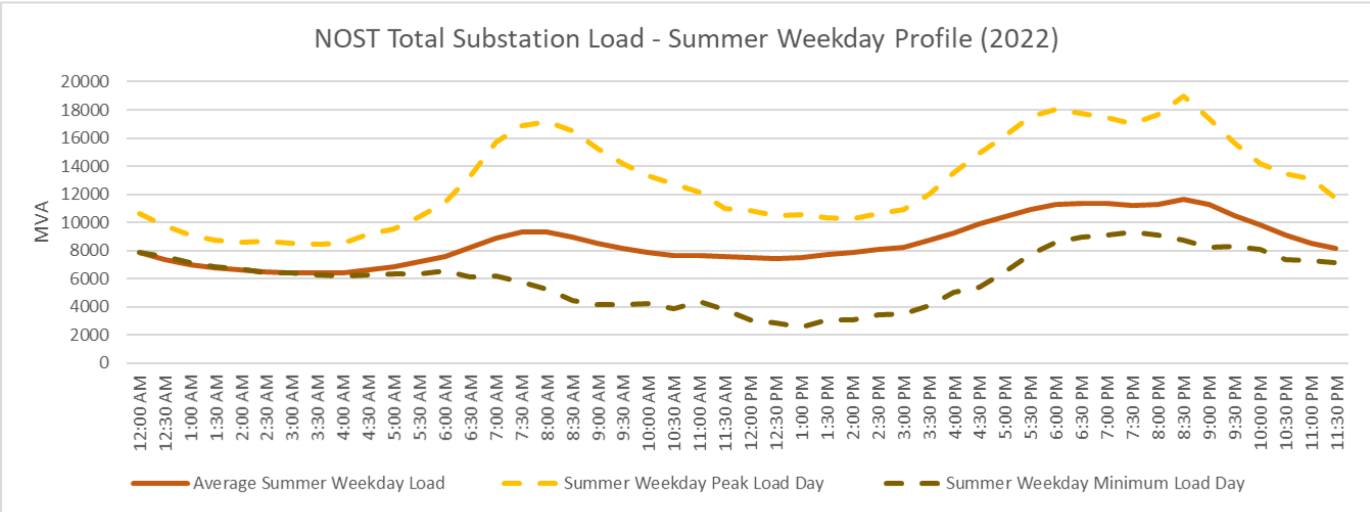


Figure 6: NOST Total Load - Daily Average, Maximum and Minimum Load Profiles (Summer)

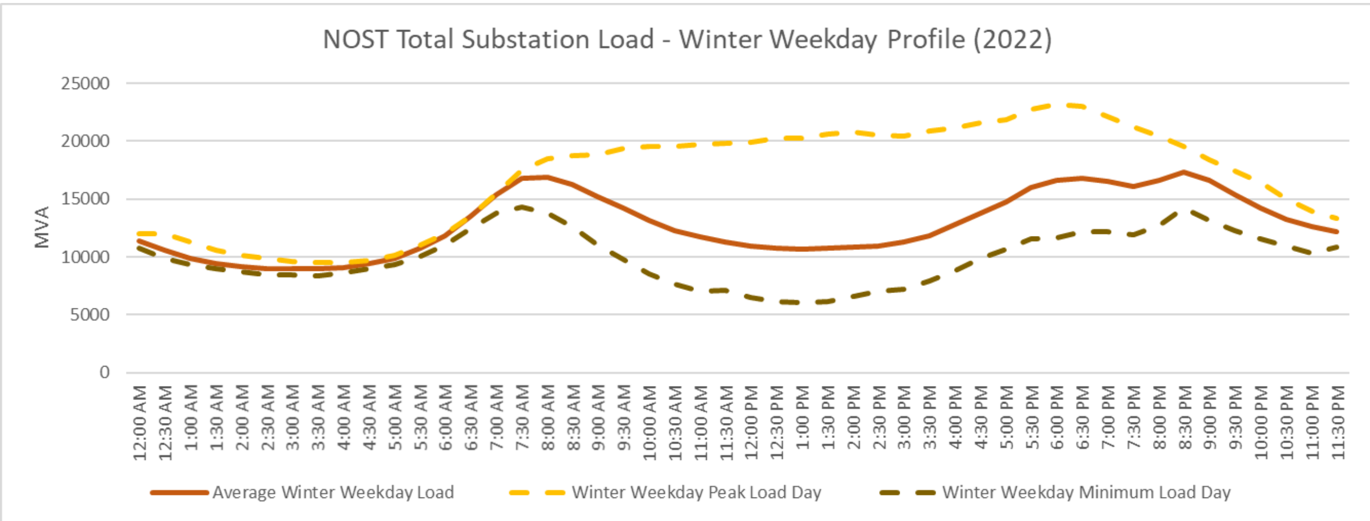


Figure 7: NOST Total Load - Daily Average, Maximum and Minimum Load Profiles (Winter)

2.4.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated **Figure 8**. The historical peak load for the past five years has also been included in the graph. These plots show the winter night peak forecast and include the new hospital load connecting in 2026. It can be seen the 50POE forecast load in the base case scenario begins to exceed the winter N-1 rating of 26.5MVA by 2026.

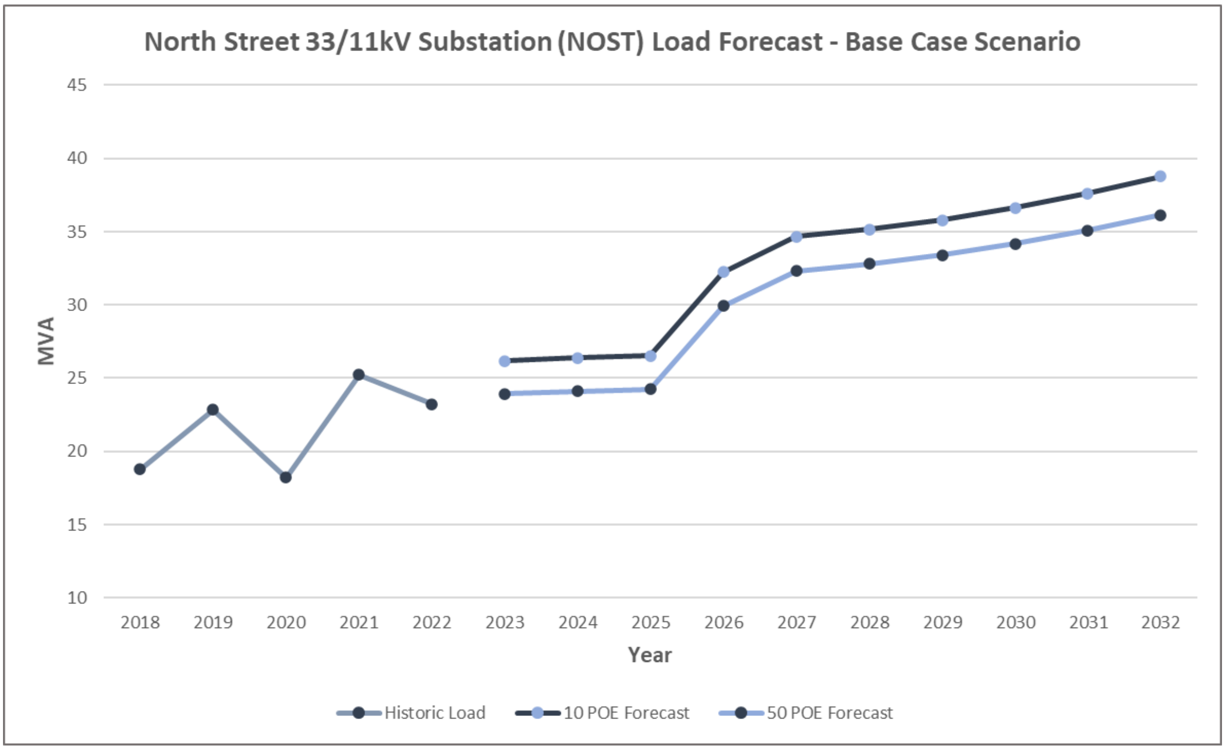


Figure 8: Network Base case load forecast

2.4.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts, including new hospital load, for the high load growth scenario are illustrated **Figure 9**. With the high growth scenario, the peak load is forecast to increase at a slightly faster rate than the base case over the next 10 years. In this scenario the 50POE forecast load exceeds the winter N-1 rating of 26.5MVA in 2026.

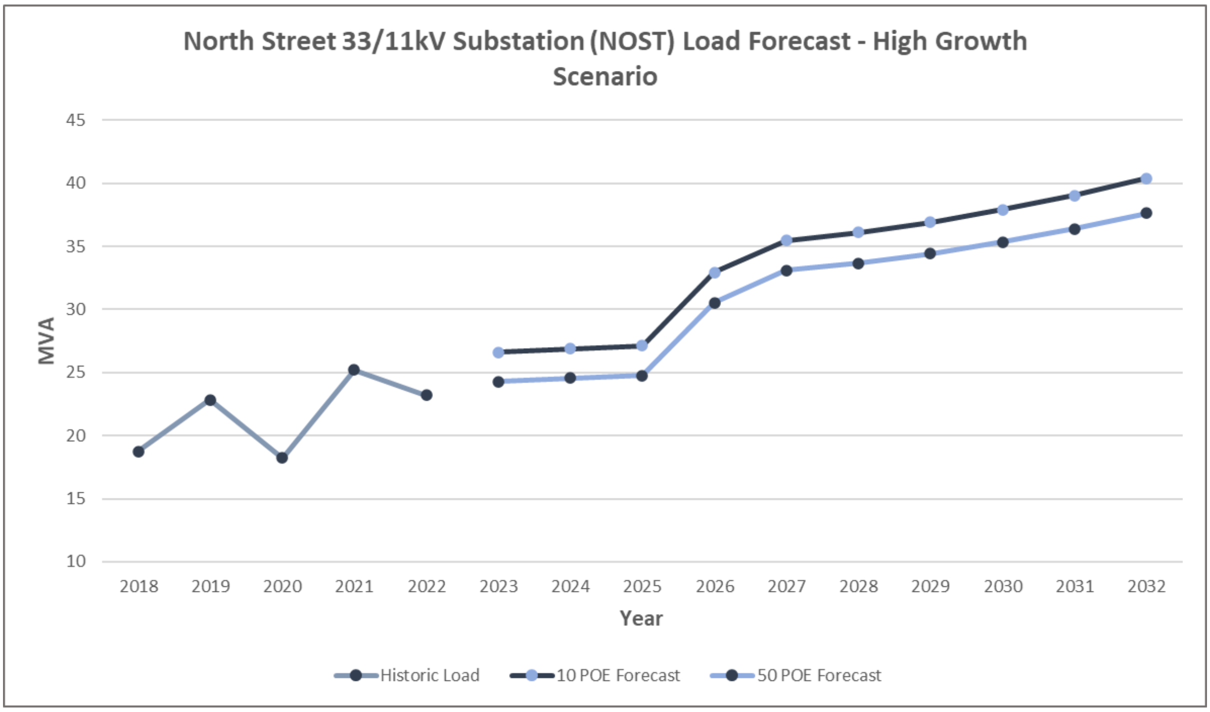


Figure 9: Network High Growth Load Forecast

2.4.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts, including new hospital load, for the low load growth scenario are illustrated **Figure 10**. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

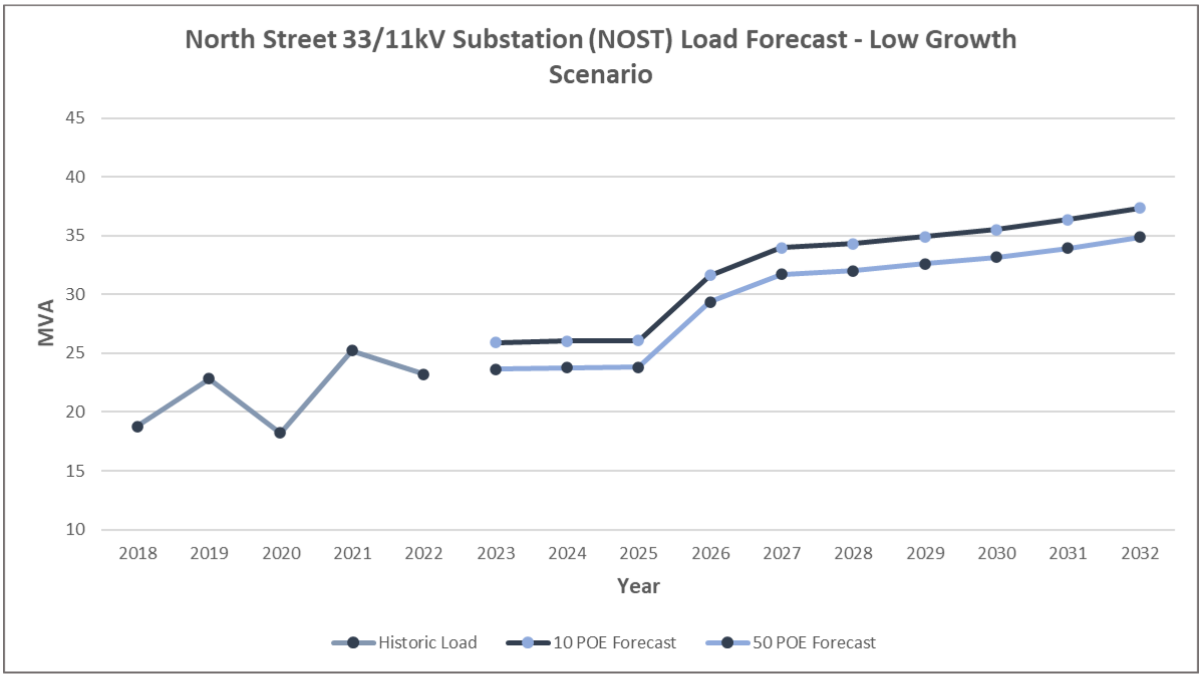


Figure 10: Network Low Growth Load Forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Aged and Poor Condition Assets

A recent condition assessment has highlighted that a number of critical assets are at end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk.

Condition data indicates that the four 11kV circuit-breakers (CBs), nine 11kV isolators and sixteen protection relays have presently reached end of life. Twelve 33kV rotary isolators have an expected retirement year of 2044 and the three 33/11kV transformers have an estimated retirement year of 2035.

The existing control building has been deemed to be structurally unsound due to internal structural wall being removed some time in the past. Temporary reinforcement of the building was undertaken in 2022 to enable it to remain in service until such time as a new building can be established.

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

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 NOST. There are presently no bus tie circuit breakers on the 33kV and 11kV buses at NOST. Under the existing substation configuration any fault within the 33kV or 11kV bus zones would result in a full substation outage. This affects almost 7,300 customers and results in a combined peak load at risk of approximately 21.9MVA.

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

3.1.2. Emerging Safety Net Non-Compliance

Due to forecast increased demand, under a credible contingency event e.g. for an outage of any of the 33/11kV transformers at NOST, benchmarked against 50% POE load, Ergon Energy will not be able to meet Safety Net restoration times as the remaining in-service transformers do not have sufficient capacity to supply the substation demand. Based on the forecast demand, this Safety Net non-compliance emerges from 2027 onwards.

3.2. Quantification of the Identified Need

3.2.1. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for each credible option which includes calculating the value of customer reliability, emergency replacement, safety and customer generation curtailment costs. For example, **Figure 11** shows the benefits of Option 2 in comparison to the counter-factual, which in this case is where no credible option is implemented and all existing plant is maintained and remains in service.

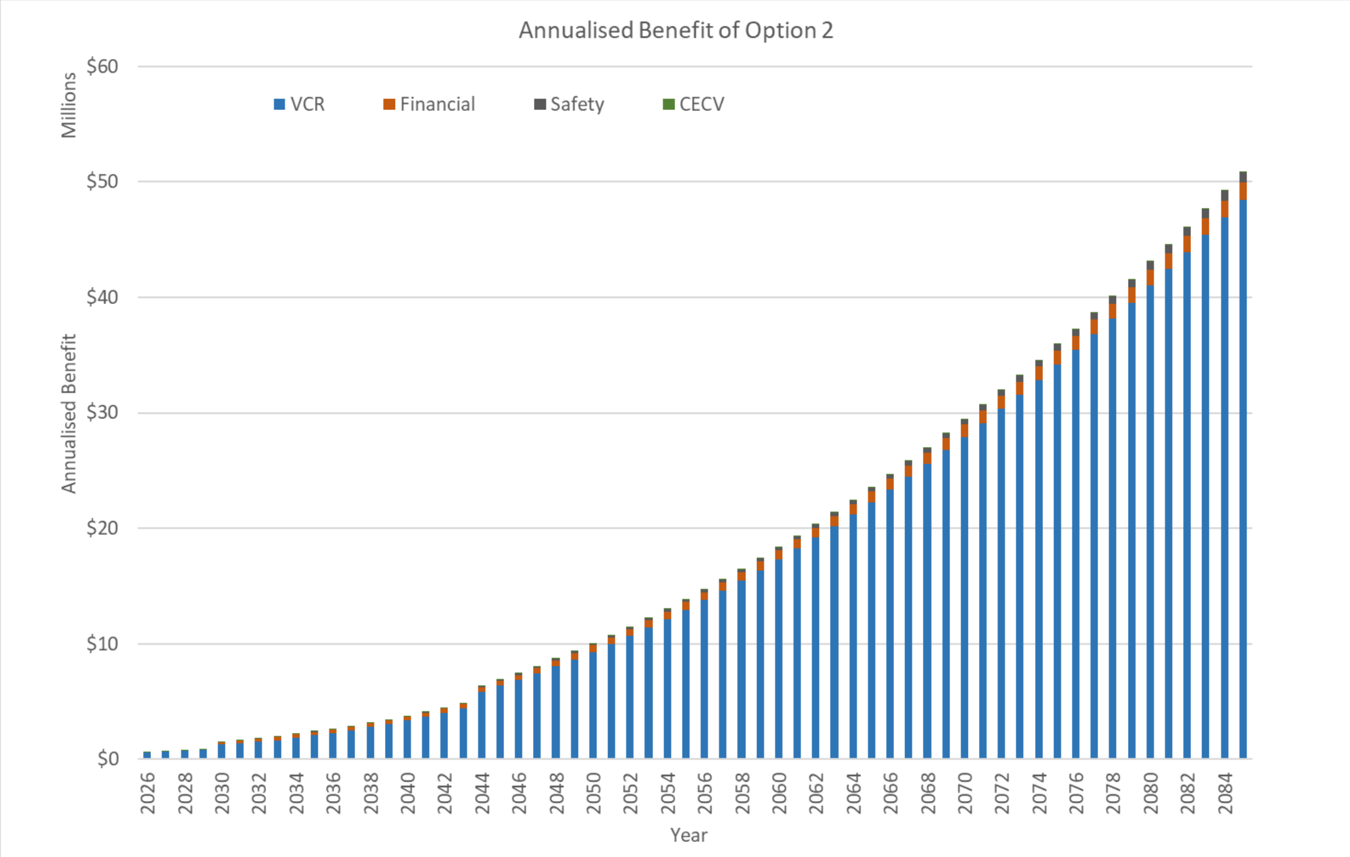


Figure 11: Annualised Benefits of Option 2 compared to the Counter-factual

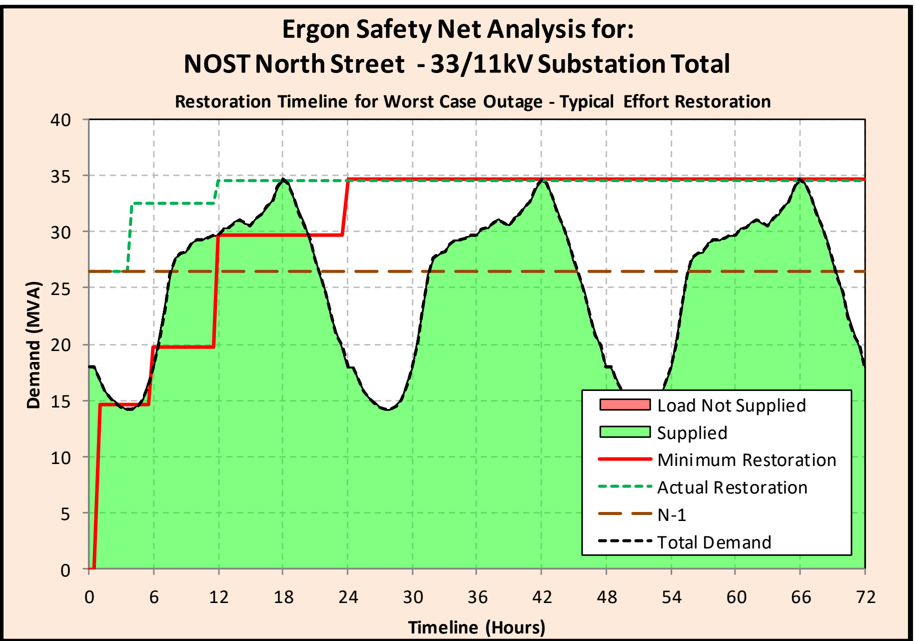
3.2.2. Emerging Safety Net Non-Compliance

NOST is categorised as a *Regional Centre* substation under Ergon Energy's Distribution Authority No. D01/99. Based on the increasing load forecast it is estimated that NOST will become Safety Net non-compliant by 2027 without any remediation.

Under the credible contingency scenario of failure of one of the three 33/11kV transformers, the winter N-1 rating of the substation is 26.5MVA (see Section 2.3). Assuming that up to 6MVA of load could be transferred to an adjoining zone substation via the 11kV network and 2MVA of mobile generation could be deployed; there will be unsupplied customer demand whenever the forecast is greater than 34.5MVA, which occurs from year 2027 onwards. Since a faulted transformer would not always be able to be put back into service within the target timeframe of 24 hours for a Regional Centre, NOST would be deemed to be Safety Net non-compliant.

This contingency scenario and Safety Net non-compliance is demonstrated in **Figure 12**.

	Load (MVA)	Time
N-1	26.5 MVA	
Sheddable load	0.0 MVA	
Load transfers	6.0	4.0 hr
Mobile generation	2.0	12.0 hr
-		
-		
-		
Repair/Bypass	1000.0 hr	



Safety Net Compliance: NOT COMPLIANT

Figure 12: Safety Net Analysis for NOST (Loss of any 33/11kV transformer) – 2027 forecast loading

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 NOST will be consistent with the base case forecast outlined in Section 2.4.4.

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 2.4.3 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 two credible network options that would address the asset condition limitations by replacing the individual assets. Based on the age profile and estimated retirement year of these assets, it is proposed to remediate these issues in three stages:

- Stage 1 (completed Dec 2022) installed temporary reinforcement to address immediate concerns with the structural integrity of the control building and protection relays.
- Stage 2 (RBD 2026) address asset limitations on the 33/11kV transformers, 11kV outdoor switchyard and control building.
- Stage 3 (RBD 2044) address asset limitations on the 33kV outdoor switchyard.

4.1.1. Option 1: NOST full substation rebuild. Rebuild outdoor 11kV and 33kV yards in situ.

This option involves replacement of primary and secondary plant by replacing the existing 3 x 10MVA 33/11kV transformers with 2 x 32MVA units and rebuilding the outdoor 11kV and 33kV yards in situ in three (3) stages.

- Summary of Stage 1 Works (completed Dec 2022)
  - Reinforce existing control building to restore structural integrity.
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 1 Differential Protection within the AFLC building (currently empty).
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 2 Differential Protection within the AFLC building (currently empty).
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 3 Differential Protection within the AFLC building (currently empty).
  - Replace nine (9) electro-mechanical protection relays with two (2) relays (GE L90, Schneider P543) at the upstream TORR BSP to provide backup protection for Transformer 1, 2 and 3 at NOST.
  - Install new DC charger and batteries.
- Summary of Stage 2 Works (RBD Mar 2026)
  - Replace three (3) 10MVA 33/11kV transformers with two (2) 32MVA 33/11kV transformers installed in situ.

- Rebuild the outdoor 11kV bus in situ.
- Replace four (4) outdoor 11kV CBs in situ.
- Replace nineteen (19) outdoor 11kV manual isolators in situ.
- Build a new control building next to the existing building.
- Replace twenty-seven (27) protection relays from the existing control building into the new control building.
- Decommission existing control building and AFLC building and installed panels. Recover if possible.

- Summary of Stage 3 Works (RBD Mar 2044)
  - Rebuild the outdoor 33kV bus in situ.
  - Replace four (4) outdoor 33kV CBs in situ.
  - Replace ten (10) outdoor 33kV manual isolators in situ.
  - Replace one (1) outdoor VT in situ.

4.1.2. Option 2: NOST full substation rebuild. Replace outdoor 11kV and 33kV yards with indoor switchboards.

This option involves replacement of primary and secondary plant by replacing the existing 3 x 10MVA 33/11kV transformers with 2 x 32MVA units and rebuilding the outdoor 11kV and 33kV yards with indoor switchboards in three (3) stages.

- Summary of Stage 1 Works (completed Dec 2022)
  - Reinforce existing control building to restore structural integrity.
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 1 Differential Protection within the AFLC building (currently empty).
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 2 Differential Protection within the AFLC building (currently empty).
  - Replace three (3) electro-mechanical protection relays with single Schneider P642 for Transformer 3 Differential Protection within the AFLC building (currently empty).
  - Replace nine (9) electro-mechanical protection relays with two (2) relays (GE L90, Schneider P543) at the upstream TORR BSP to provide backup protection for Transformer 1, 2 and 3 at NOST.
  - Install new DC charger and batteries.
- Summary of Stage 2 Works (RBD Mar 2026)
  - Replace three (3) 10MVA 33/11kV transformers with two (2) 32MVA 33/11kV transformers.

- Build a new masonry control and switchgear building an indoor 11kV switchboard and protection/control. Allow space for a future indoor 33kV switchboard. The control building shall be design based off the concept design standard Z7-32 and its requirements.
- Replace twelve (12) outdoor 11kV CBs with a new indoor 11kV switchboard.
- Replace nineteen (19) outdoor 11kV manual isolators with a new indoor 11kV switchboard.
- Replace twenty-seven (27) protection relays from the existing control building into the new control and switchgear building.
- Install cabling from the new 11kV switchboard to the new transformers.
- Relocate existing 11kV OH feeder conductor and 11kV UG exit cables to connect to the new 11kV switchboard.
- Decommission existing control building and AFLC building and installed panels. Recover if possible.

- Summary of Stage 3 Works (RBD Mar 2044)
    - Replace five (5) outdoor 33kV CBs with a new indoor 33kV switchboard.
    - Replace ten (10) outdoor 33kV manual isolators with a new indoor 33kV switchboard.
    - Replace one (1) outdoor VT with a new indoor 33kV switchboard.
    - Install HV cabling to connect the 33kV switchboard to the transformers.

4.2. Assessment of Non-Network Solutions

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

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

4.2.1. Demand Management (Demand Reduction)

The DEM team has completed a review of the NOST customer base and considered a number of demand management technologies. Asset safety and performance risks are the key project drivers (i.e. the need) at NOST. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections.

4.2.2. Network Load Control

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

There are 3,832 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 2,300kVA[1] is available.

NOST LC signals are controlled from Torrington Bulk Supply Substation (TORR). 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 TORR exceeds 110MW. This strategy does not directly address demand peaks experienced at NOST. Tariff 33 air-conditioning 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.

4.2.3. 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.

4.2.4. 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.

4.2.5. 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.

4.2.6. 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.

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

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.

4.2.7. Customer Solar Power Systems

A total of 1,565 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 7,760kVA.

The daily peak at NOST 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.

4.2.8. Non-Network Solution Summary

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 provide the magnitude of network support required in the NOST area to address the identified need. It should be noted that Ergon Energy have already published a Notice of No Non-Network Options report outlining that Ergon Energy do not consider that a Non-Network Solution is possible in this case.

4.3. Preferred Network Option

Ergon Energy’s preferred internal network option is Option 2: NOST full substation rebuild - replace outdoor 11kV and 33kV yards with indoor switchboards.

Upon completion of these works, the asset safety and reliability risks at NOST will be addressed and network capacity increased to allow connection of the new Toowoomba Hospital in 2026. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete, non-compliant and high maintenance assets, while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $17.04 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in July 2023 and construction completed by March 2026.

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

On 3 March 2023, Ergon Energy published the Draft Project Assessment Report providing details on the identified need at NOST. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the need for investment.

In response to the Draft Project Assessment Report, Ergon Energy received no submissions by 17 April 2023, which was the closing date for submissions to the Draft Project Assessment Report.

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 National Electricity Market (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

6.1.1. Changes in involuntary load shedding and customer interruptions

Involuntary load shedding and customer interruption occurs when 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 and customer interruption benefits of a credible option are calculated by multiplying the expected unserved energy, assuming that the option is completed, 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 $43.35/kWh, which has been derived from the AER 2022 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 at NOST.

Customer export curtailment value (CECV) represents the detriment to all customers from the curtailment of DER exports (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 AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the NOST 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
- Changes in timing of expenditure
- Changes in load transfer capacity and capacity of Embedded Generators to take up load
- Changes in network losses
- Option value

6.2.1. Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the NOST area at present, any 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. Changes in Timing of Expenditure

None of the credible options included in this RIT-D assessment is expected to affect the timing of other distribution investments for unrelated identified needs.

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

None of the credible options included in this RIT-D assessment are 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 NOST area.

6.2.5. Changes in Network 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 network losses.

6.2.6. 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[2].

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

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The Regulatory Investment Test for Distribution requires Ergon Energy to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the National Electricity Market.

Accordingly, a base case Net Present Value (NPV) comparison of the alternative development options has been undertaken.

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.

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated WACC. The interest on borrowings is included in the Total Project Cost for which approval is being sought as it represents a legitimate cost of network augmentation.

7.3. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 2. Of the options assessed, Option 2 provides the greatest net economic benefit.

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

Table 2: Base case NPV ranking table

BASE CASH FLOWS NPV ANALYSIS							
PROJECT:	North Street Asset Limitation						
Results displayed in $000s							
WEIGHTED AVERAGE RESULT ACROSS ALL SCENARIOS							
AVERAGE Option	Option Name	Rank	Net NPV	Capex NPV	Opex NPV	Benefits NPV
1	Option 1: Full substation re-build in situ	2	**112,205**	-15,850	-4,702	132,757
2	Option 2: Full substation re-build with indoor 11kV and 33kV switchboards	1	**145,480**	-14,271	-4,245	163,996

8. CONCLUSION

The Final Project Assessment Report (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 proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

8.1. Preferred Option

Ergon Energy's preferred internal network option is Option 2: NOST full substation rebuild - replace outdoor 11kV and 33kV yards with indoor switchboards.

Upon completion of these works, the asset safety and reliability risks at NOST will be addressed and network capacity increased to allow connection of the new Toowoomba Hospital in 2026. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete, non-compliant and high maintenance assets, while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $17.04 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has design commencing in July 2023 and construction completed by March 2026.

8.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

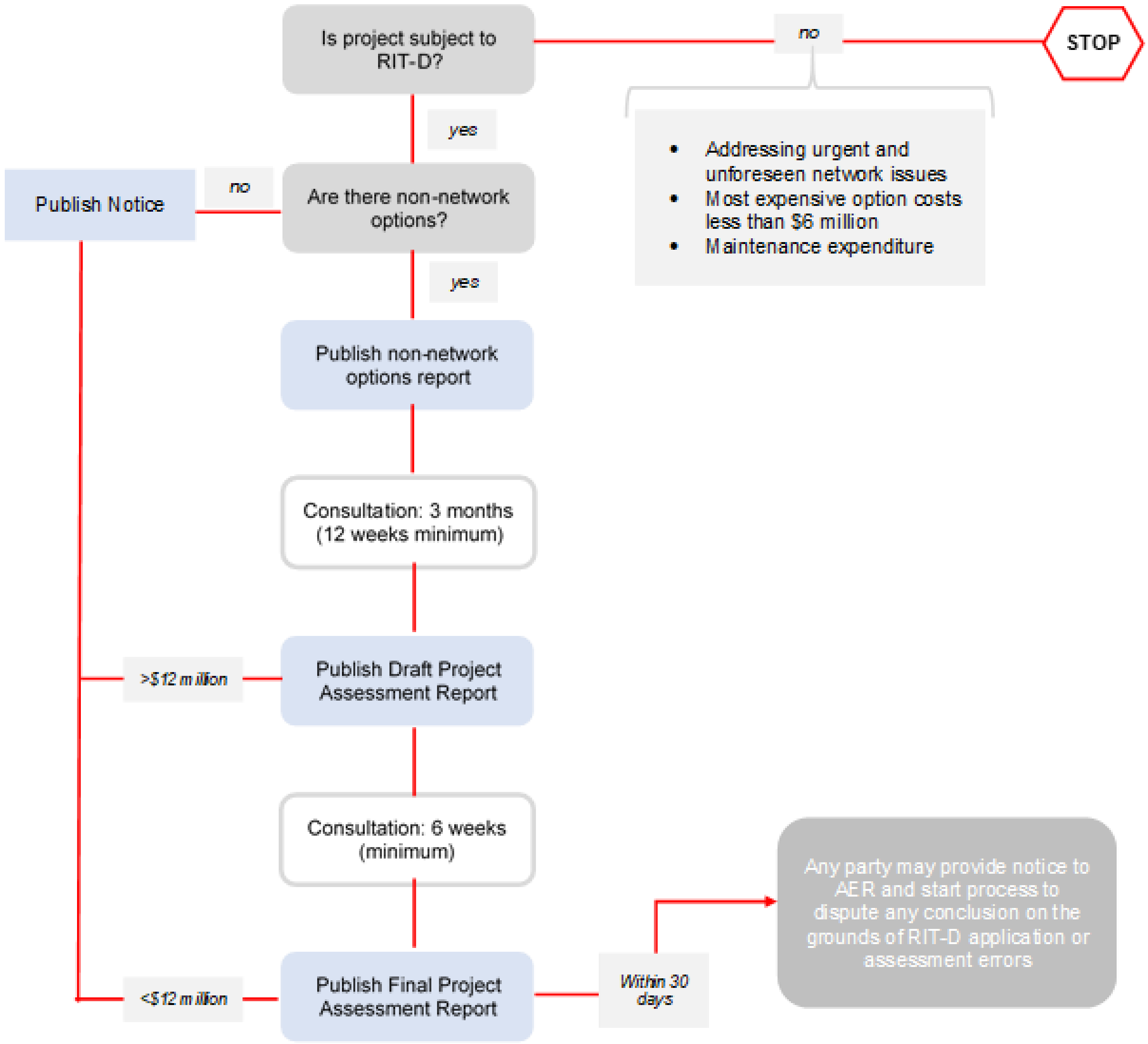
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

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

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the 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 & 5
(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	7.3
(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.