Regulatory Investment Test for Distribution (RIT-D)

Mona Park Network Limitation

Final Project Assessment Report

3 September 2021

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

Mona Park 66/11kV Substation (MOPA) is located on the northern bank of the Burdekin River about 25km south-west of Ayr. The substation is part of the Burdekin 66kV sub-transmission network and takes supply from T193 Clare South 132/66kV Bulk Supply Substation.

Mona Park Substation consists of two 4MVA 66/11kV transformers and an indoor 11kV switchboard with four outgoing feeders supplying approximately 430 premises, of which 97 are residential and 333 are commercial, agricultural and industrial. Mona Park Substation is presently supplied via two incoming 66kV feeders, one from T193 Clare South 132/66kV Bulk Supply Substation and one from Ayr Substation.

A substation condition assessment of Mona Park Substation was completed in 2019 and has identified some primary and secondary plant and equipment that are recommended for retirement based on Condition Based Risk Management (CBRM) analysis.

The assessment identified that the two 66/11kV power transformers, five 66kV isolators, six of the segmented bus insulators and most of the protection relays are at the end of their serviceable life. Additionally, the transformers have no bunding and require firewall separation to the adjacent control building.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard, and reliability risk to the customers supplied from Mona Park Substation.

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

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

Ergon Energy published a Notice of no non-network options for the above described identified need on 31 August 2021.

Two potentially feasible options have been investigated:

- **Option A:** Replace existing 4MVA transformers with a single 10MVA transformer with a mobile substation connection point
- **Option B:** Replace existing 4MVA transformers with two 6.3MVA transformers

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 A, to recover the existing transformers, install a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replace the problematic 66kV isolators, replace the segmented bus insulators and replace protection relays at Mona Park Substation.

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 Mona Park network area.

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

1.1. Structure of the Report

This report:

- 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.

1.2. 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 recover the existing transformers, install a new 10MVA 66/11kV transformer with compliant bunding and new

11kV transformer cables, replace the problematic 66kV isolators, replace the segmented bus insulators and replace protection relays at Mona Park Substation.

1.3. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Mona Park substation supplies a rural area in the Burdekin region that consists predominantly of irrigated sugar cane farms. Mona Park Substation provides electricity supply to approximately 430 premises, of which 97 are residential and 333 are commercial, agricultural and industrial.

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

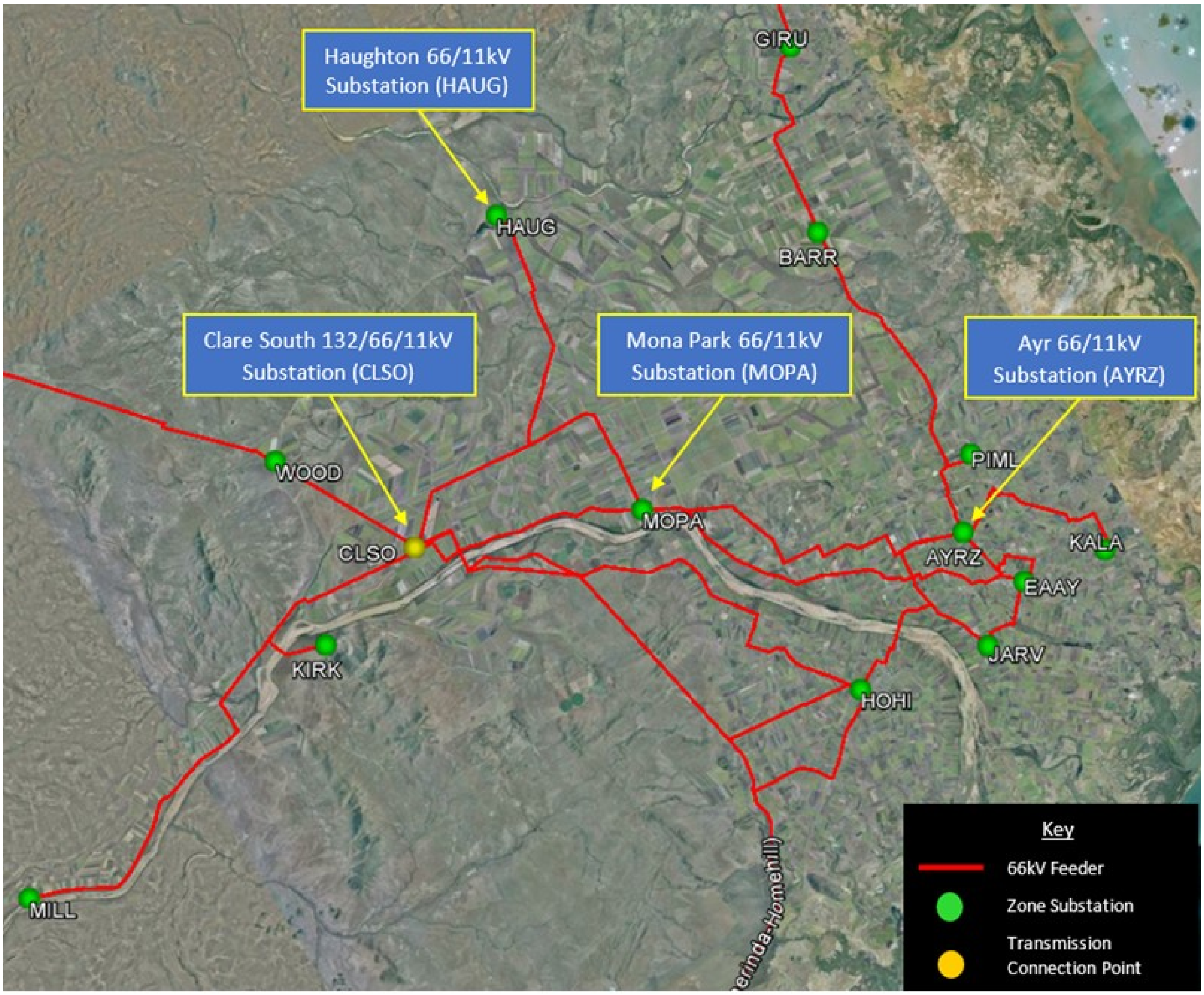


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

Mona Park 66/11kV Substation (MOPA) is located on the northern bank of the Burdekin River about 25km south-west of Ayr. The substation is part of the Burdekin 66kV sub-transmission network and takes supply from T193 Clare South 132/66kV Bulk Supply Substation.

Mona Park Substation was established in the late 1960s according to applicable design and construction standards during that time. It has an outdoor 66kV switchyard, two fuse protected 4MVA 66/11kV power transformers and a control building with an indoor 11kV switchboard.

The 11kV indoor switchboard comprises seven 11kV retrofitted circuit breakers and two bus sections separated by a bus section circuit breaker which is operated normally open for safety and protection purposes (i.e. due to 66kV transformer fusing). Each bus section has two outgoing 11kV rural feeders.

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

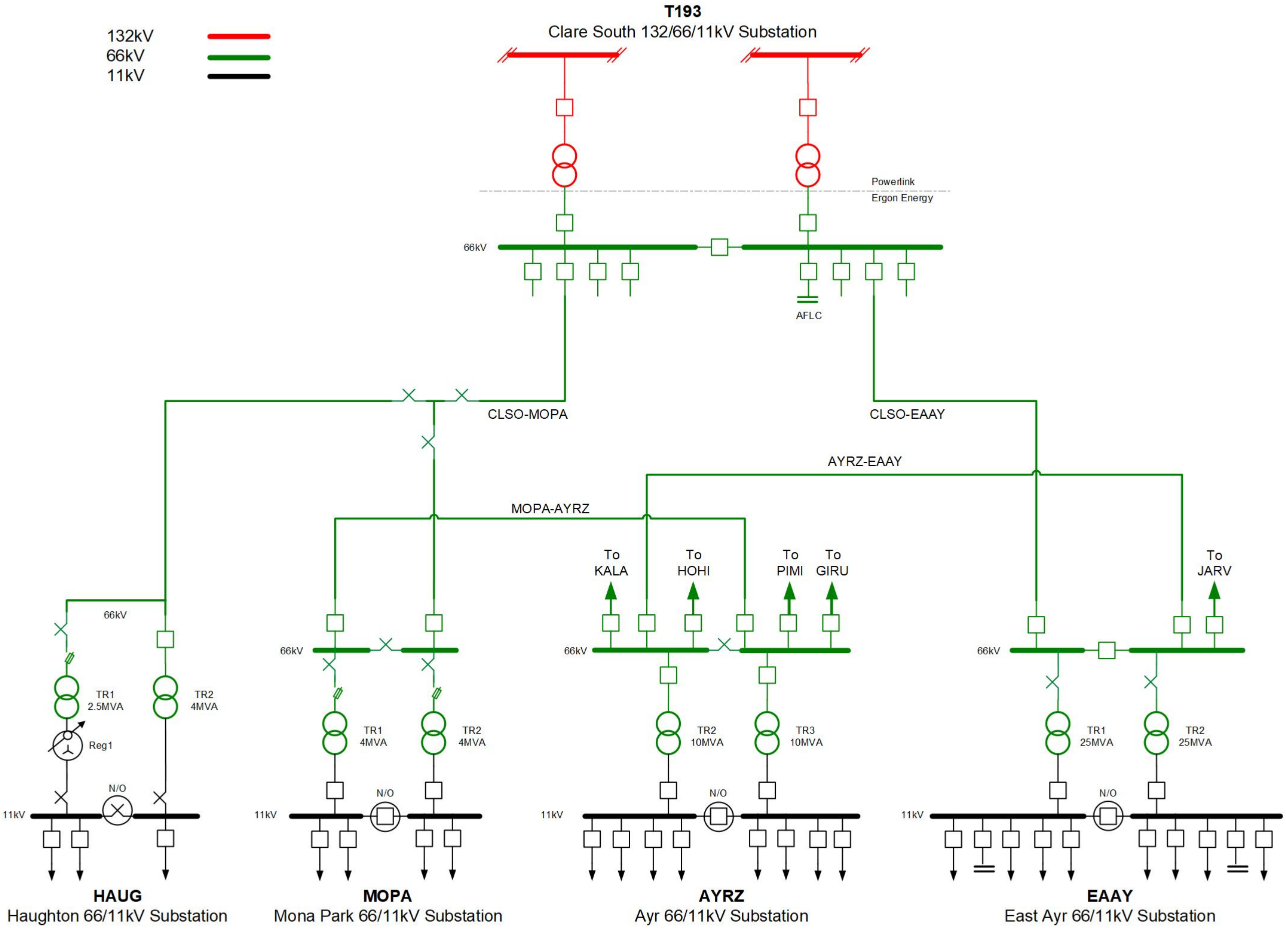


Figure 2: Existing network arrangement (schematic view)

Figure 3: Mona Park Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Mona Park Substation comprises a mix of residential and commercial/agricultural/industrial customers. The load is summer peaking, and the annual peak loads are predominantly driven by pumping and irrigation for the local sugarcane crops.

2.3.1. Full Annual Load Profile

The full annual load profile for Mona Park Substation over the 2020/21 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

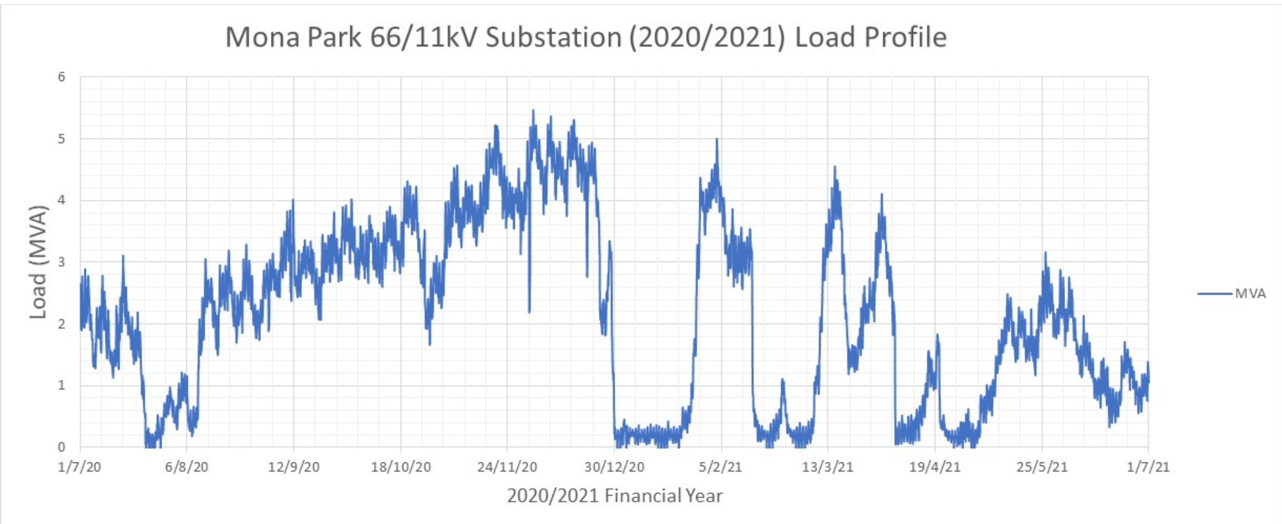


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Mona Park Substation over the 2020/21 financial year is shown in Figure 5.

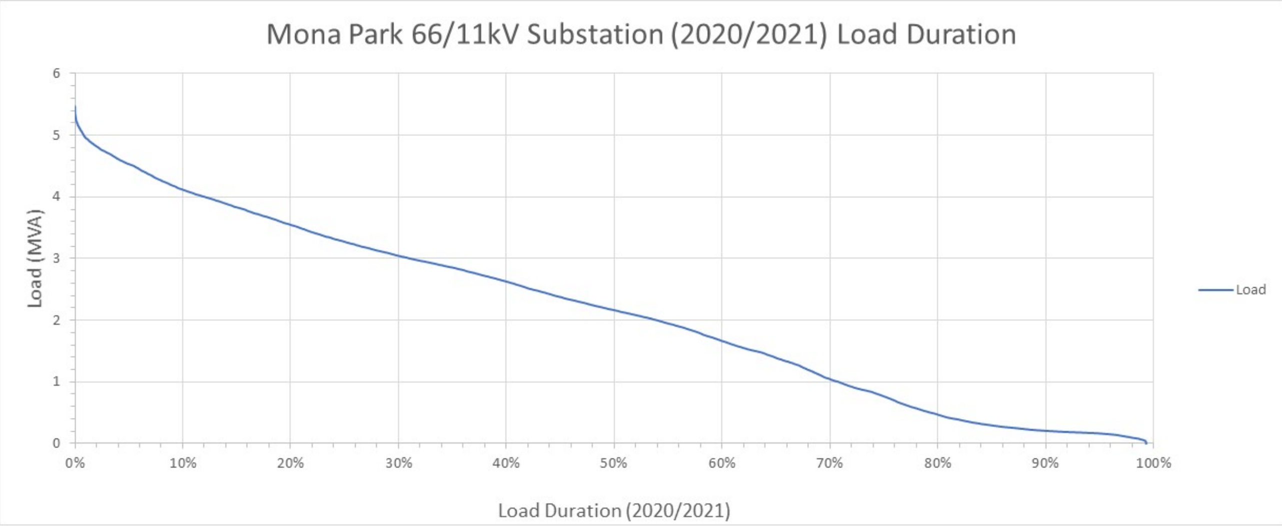


Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 6. It can be noted that the summer peak loads at Mona Park Substation are historically experienced in the late afternoon and evening.

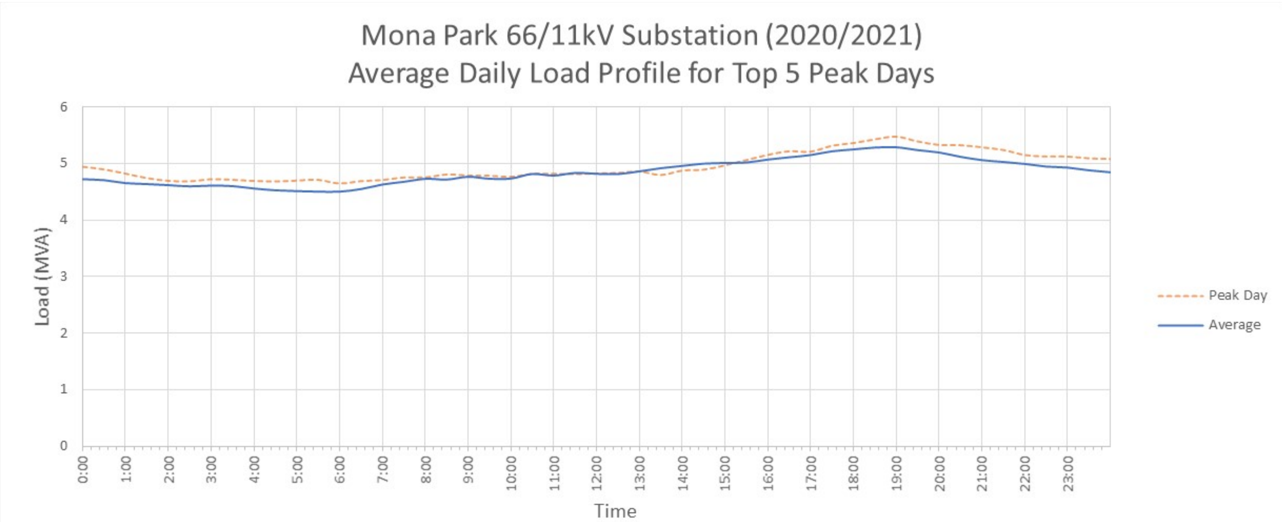


Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

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

It can be noted that the historical annual peak loads have fluctuated over the past five years, primarily due to seasonal variation in pumping and irrigation load due to the quantity and timing of rainfall in the area. It can also be noted that the peak load is forecast to increase slightly over the next 10 years under the base case scenario.

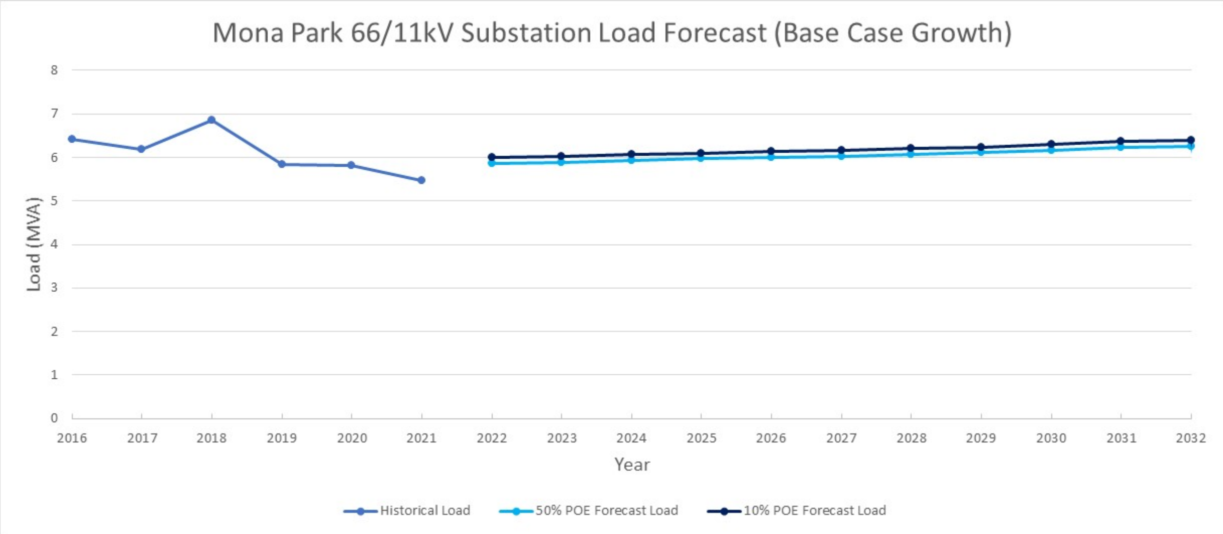


Figure 7: Substation base case load forecast

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.

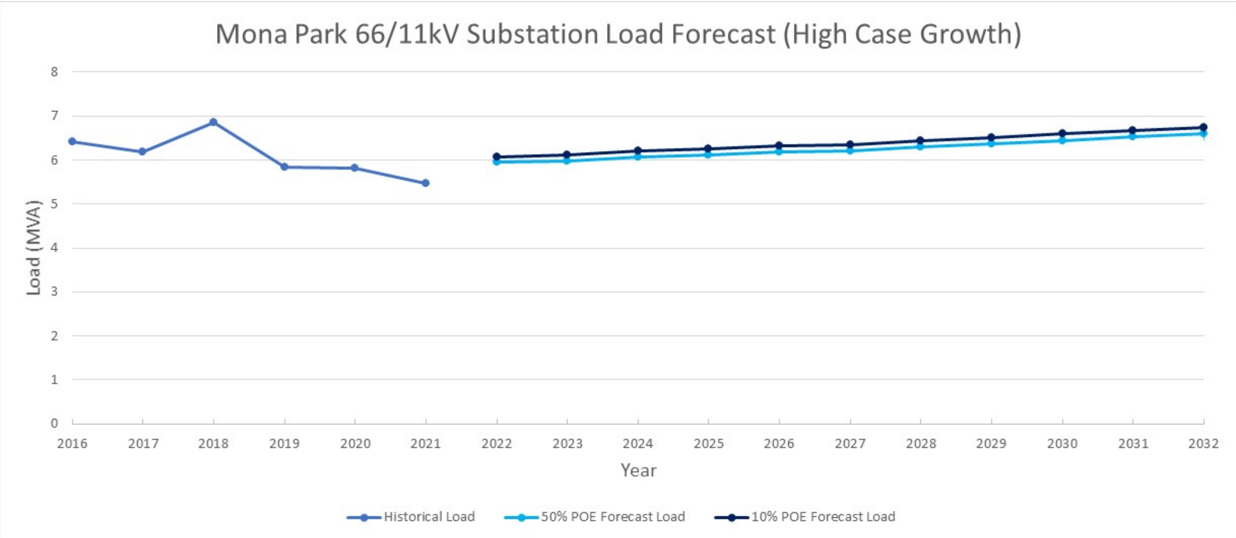


Figure 8: Substation high growth load forecast

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.

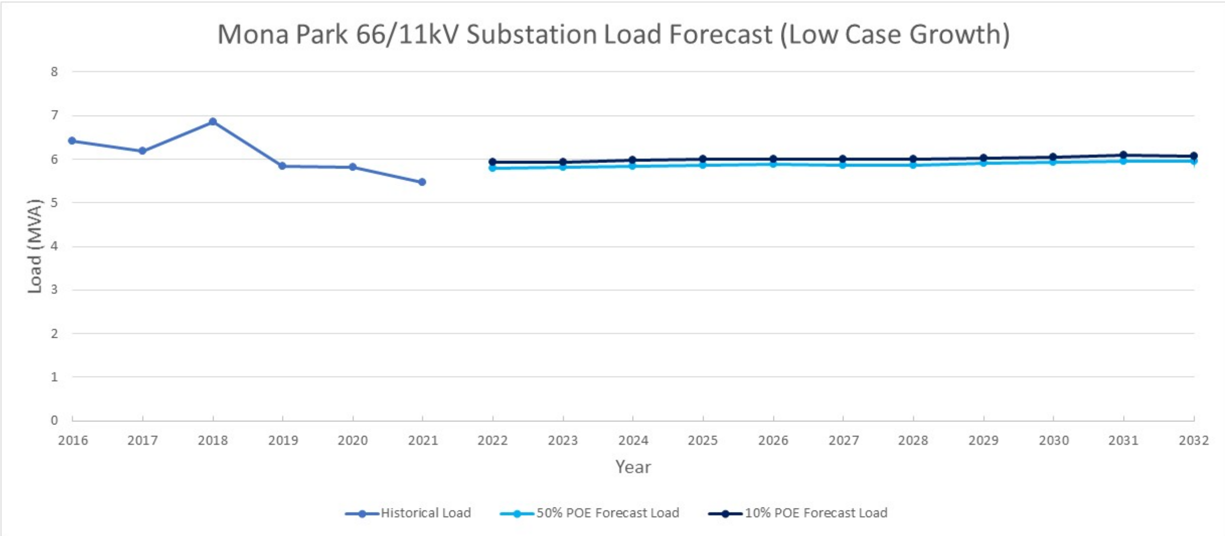


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

A recent condition assessment at Mona Park Substation 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 two 66/11kV power transformers, five 66kV isolators, six of the segmented bus insulators and most of the protection relays at Mona Park Substation are reaching end of life. Additionally, the transformers have no bunding and require firewall separation to the adjacent control building.

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 through the increased likelihood of protection relay mal-operation and catastrophic failure of the power transformers. There is also a considerable risk of environmental harm due to loss of oil from the power transformers, which would require clean up and rectification. Ergon considers that without rectification, this Safety risk would not be reduced 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 Mona Park Substation.

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

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

A risk assessment has been undertaken on the condition of the deteriorated assets at Mona Park Substation and Ergon Energy has deemed that without undertaking remediation the safety risk associated with the asset condition would not be reduced to be So Far As Is Reasonably Practicable (SFAIRP). Secondly, there is also an environmental risk associated with the un-bunded transformers that will also not be As Low As Reasonably Practicable (ALARP). As such, retention of these assets in their current condition is not considered an acceptable option.

3.2.2. Increased risk of involuntary load shedding going forward

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.

Involuntary load shedding is derived by the quantity in MWh of involuntary load shedding required 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 $37/kWh, which has been derived from the AER 2020 VCR values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

The probability of asset failure increases over time as the assets condition and performance deteriorates and therefore the expected risk costs also increases over time. Ergon Energy uses a Weibull distribution to estimate probability of asset failure for transformers and circuit breakers and uses historical average outage rates to estimate probability of asset failure for other asset types.

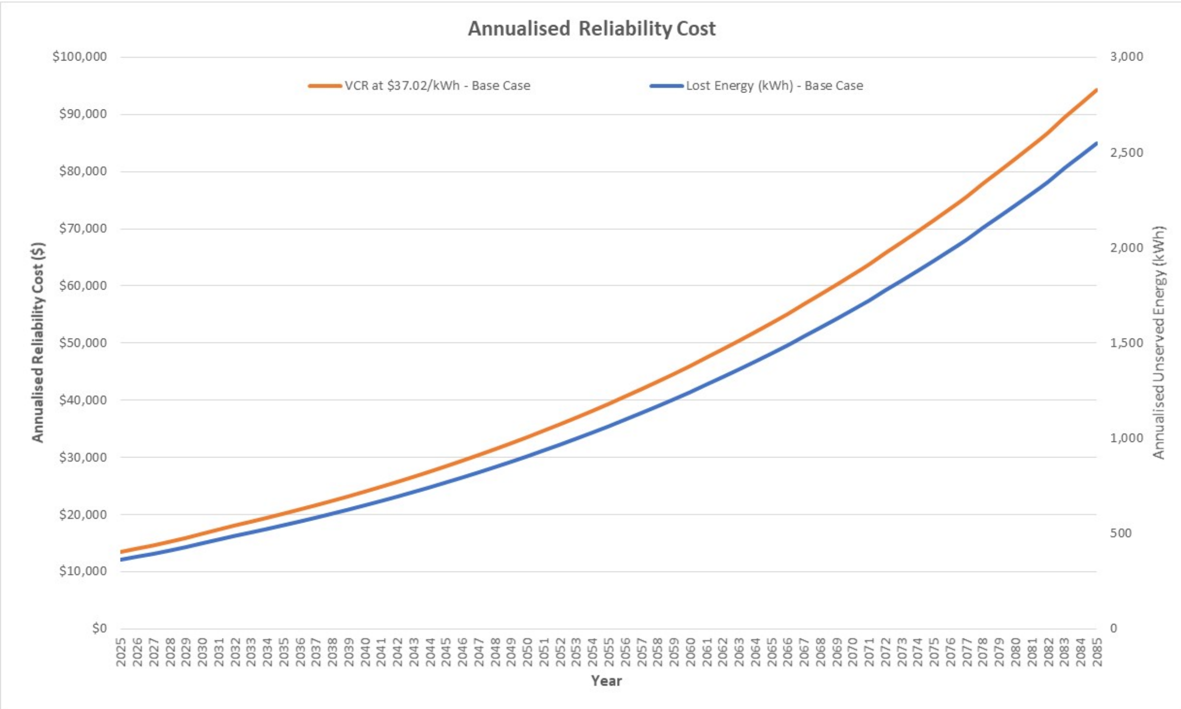


Figure 10 Estimated Annualised Reliability Cost associated with the deteriorating asset condition at Mona Park Substation if no credible option is commissioned

The plot above shows the estimated increase in the cost of unserved energy over the assessment period associated with deteriorating asset condition at Mona Park Substation if no credible option is commissioned.

Note that the cost of unserved energy over the assessment period has been based on an uninflated VCR rate of $37/kWh.

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 Mona Park 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 two credible network options that will address the identified need.

4.1.1. Option A: Replace existing 4MVA transformers with a single 10MVA transformer with a mobile substation connection point

This option involves recovering the two existing transformers and installing a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replacing the problematic 66kV isolators, replacing the segmented bus insulators and addressing secondary systems limitations in order to address the identified need.

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

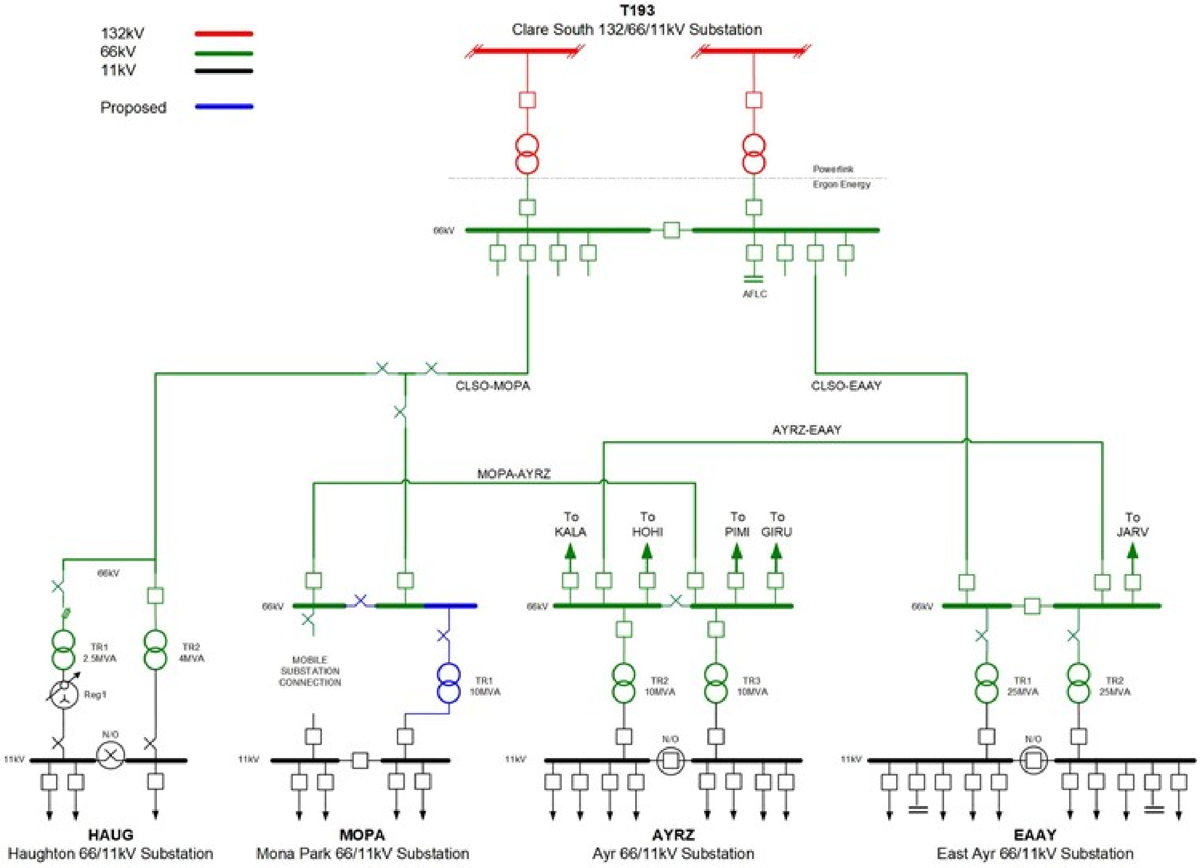


Figure 11: Option A proposed network arrangement (schematic view)

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $5.55 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost.

4.1.2. Option B: Replace existing 4MVA transformers with two 6.3MVA transformers

This option involves recovering the two existing transformers and installing two new 6.3MVA 66/11kV transformers with compliant bunding and new 11kV transformer cables, replacing the problematic 66kV isolators, replacing the segmented bus insulators and addressing secondary systems limitations in order to address the identified need.

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

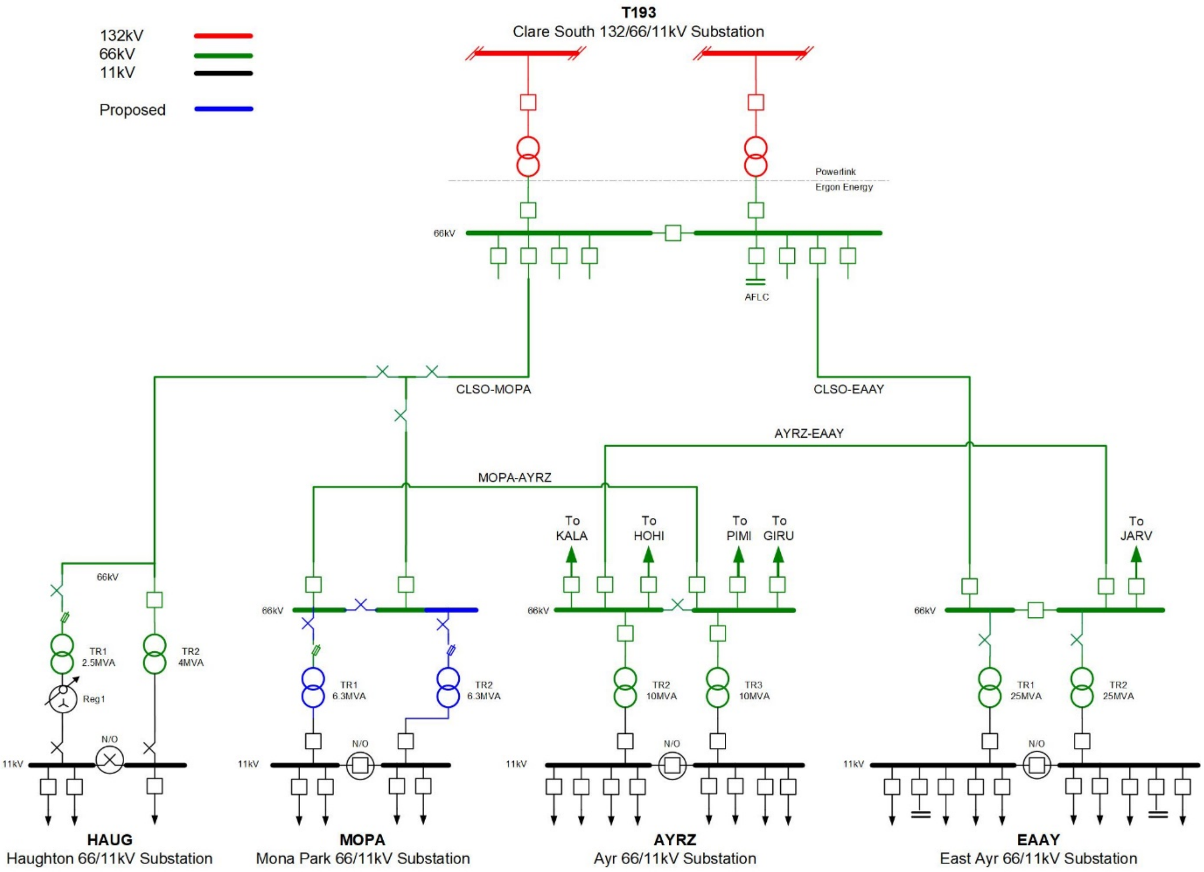


Figure 12: Option B proposed network arrangement (schematic view)

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $6.275 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost.

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 Mona Park 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 Mona Park. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections.

Network Load Control

The residential customers and irrigation load appear to drive the daily peak demand which generally occurs between 6:00pm and 8:00pm.

There are 84 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 50kVA[1] is available.

Mona Park Substation LC signals are controlled from T193 Clare South 132/66kV Bulk Supply Substation. 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 T193 Clare South 132/66kV Bulk Supply Substation exceeds 81MW. This strategy does not directly address demand peaks experienced at Mona Park. 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.

4.2.2. 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.

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

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 would not address the identified network requirement to provide a continual reliable supply to this part of the network on an ongoing basis.

Large-Scale Customer Generation (LSG)

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

This option could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available that could connect at 11kV in the Mona Park catchment area and provide a continual reliable supply to this part of the network on an ongoing basis.

Customer Solar Power Systems

A total of 59 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 819kVA.

The daily peak demand is driven by agricultural customer demand and the peak generally occurs between 6:00pm and 8:00pm. 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.

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.

4.2.1. 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 Mona Park area to address the identified need.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is Option A, to recover the existing transformers, install a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replace the problematic 66kV isolators, replace the segmented bus insulators and replace protection relays at Mona Park Substation.

Upon completion of these works, the asset safety and reliability risks at Mona Park Substation will be addressed. The preferred option will provide a reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant 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 $5.55 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 late-2021 and construction completed by January 2025.

5. 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.

5.1. 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

5.1.1. Changes in Involuntary Load Shedding

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 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 $37/kWh, which has been derived from the AER 2020 VCR values. In particular, Ergon Energy has weighted the AER estimates according to the make-up of the specific load considered.

The plot below shows the estimated reduction in the cost of unserved energy over the assessment period for each of the credible options compared to the base case. The reduction in expected unserved energy that the credible option is expected to deliver has been included as a material market benefit.

Note that the cost of unserved energy over the assessment period has been based on an uninflated VCR rate of $37/kWh.

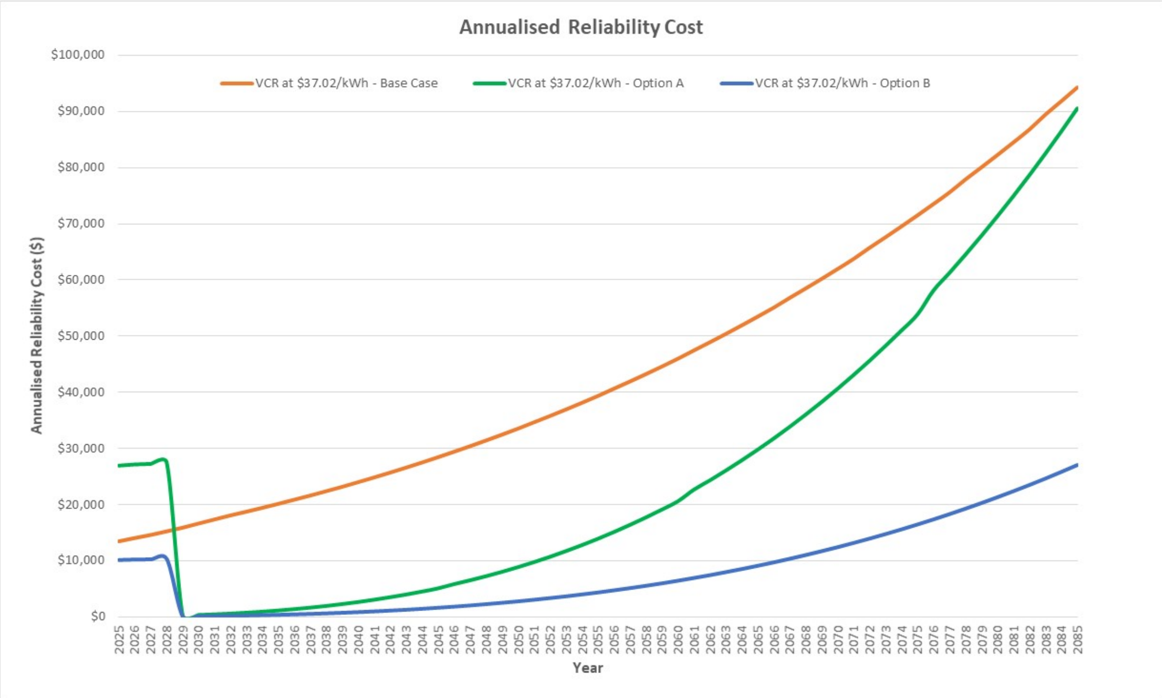


Figure 13 Estimated Annualised Reliability Cost for each of the credible options compared to the base case

5.2. 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 capability
- Changes in network losses
- Option value

5.2.1. 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 Mona Park area at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.1. 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.

5.2.2. 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.

5.2.3. Changes in Load Transfer Capability

None of the credible options included in this RIT-D assessment are expected to have an impact on the load transfer capability between the zone substations in the Mona Park area.

5.2.4. 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.

5.2.1. 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 options considered in treating the identified need included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future. More specifically, the load and energy forecasts for the low, medium and high cases have no impact on future stages of either option, and as such Option Value has not been considered.

[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

6. DETAILED ECONOMIC ASSESSMENT

6.1. 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 Net Present Value (NPV) comparison of the alternative development options 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.

6.2. 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.

Table 1 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
Project Costs	Standard estimates	-40%	+40%
Opex Costs	Calculated Opex	-10%	+10%

Table 1: Economic parameters and sensitivity analysis factors

6.3. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 2.

Option	Option Name	Rank	Net Economic Benefit ($k)	PV of Capex ($k)	PV of Opex ($k)	PV of Benefits ($k)
A	Replace existing 4MVA transformers with a single 10MVA transformer with a mobile substation connection point	1	-5,333	-5,551	-147	364
B	Replace existing 4MVA transformers with two 6.3MVA transformers	2	-5,368	-6,275	-43	950

Table 2: Base case NPV ranking table

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 3 shows the percentage of times each option was the most economical across the simulations and also the average NPV cost of all the simulations.

Option Number	Option Name	Rank 1	Rank 2	Average NPV ($k)
A	Replace existing 4MVA transformers with a single 10MVA transformer with a mobile substation connection point	48.6%	51.4%	-5,274
B	Replace existing 4MVA transformers with two 6.3MVA transformers	51.4%	48.6%	-5,327

Table 3: Monte Carlo Analysis for Base Case Forecast

Option A is the lowest cost option in the weighted average NPV results across the two identified options. Option A is also the lowest cost option in the weighted average NPV results in 48.6% 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 identified need and is therefore the recommended development option.

7. 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.

7.1. Preferred Option

Ergon Energy's preferred option is Option A, to recover the existing transformers, install a new 10MVA 66/11kV transformer with compliant bunding and new 11kV transformer cables, replace the problematic 66kV isolators, replace the segmented bus insulators and replace protection relays at Mona Park Substation.

Upon completion of these works, the asset safety and reliability risks at Mona Park Substation will be addressed. The preferred option will provide a reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant 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 $5.55 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 late-2021 and construction completed by January 2025.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

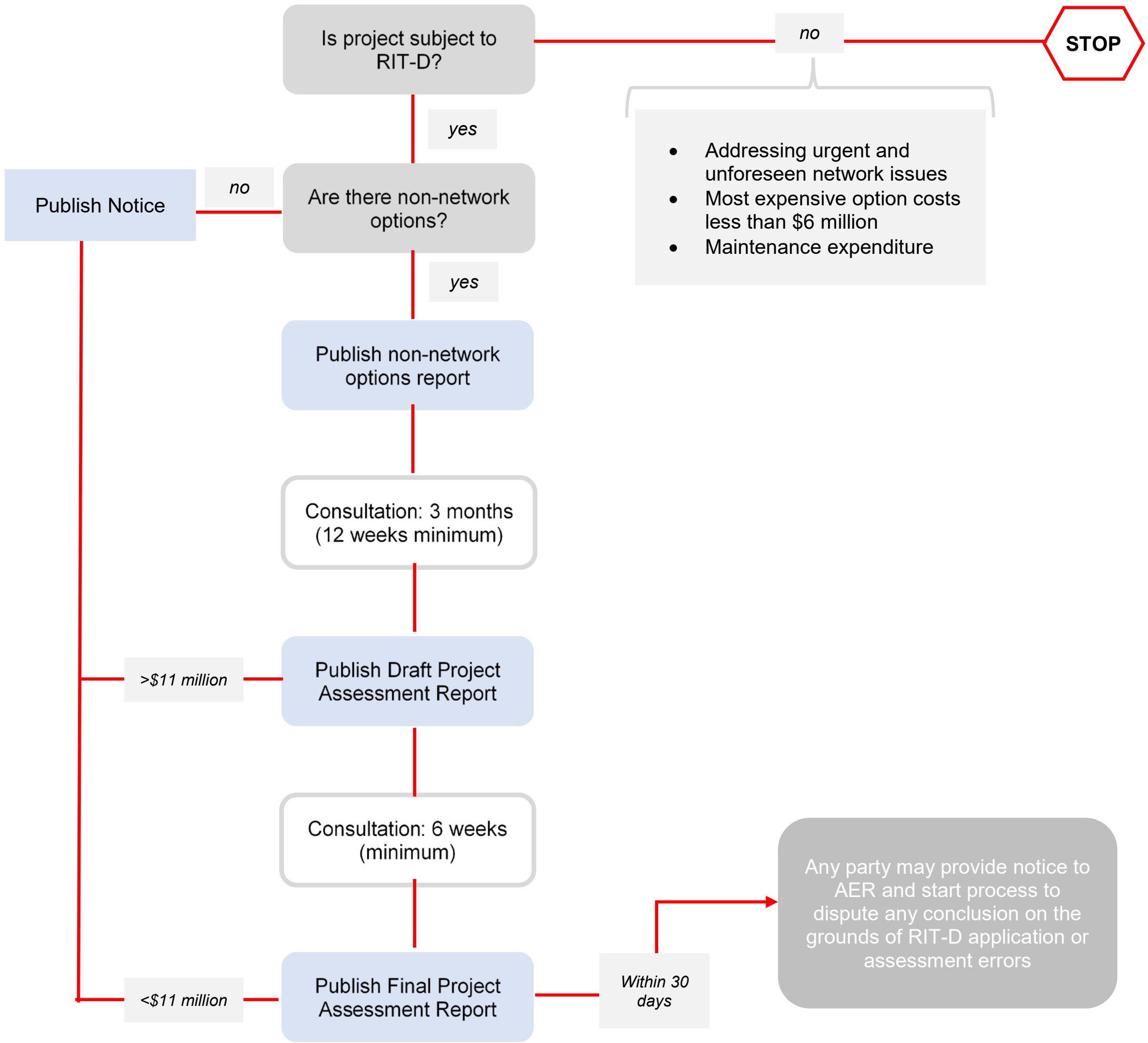
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. 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;	N/A
(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	5
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(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	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.3
(10) the identification of the proposed preferred option	7.1
(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	7.1 & 7.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

APPENDIX A – THE RIT-D PROCESS



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