Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Mount Garnet Network Area

Final Project Assessment Report

22 June 2023

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

Mount Garnet Zone 66/22kV Substation (MOGA) is located north-west of the Atherton Tablelands and is supplied by one incoming 66kV feeder (3MTG) from Atherton Zone Substation (ATHE). On 3MTG, there is also a tee-off to Customer Substation (KAGA). MOGA provides electricity supply, via two 4MVA transformers, to approximately 533 customers, of which 72% are residential and 28% are commercial and industrial, with a peak load of 2.4 MVA

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

The following have been deemed to reach their retirement age:

- 66/22kV 4MVA Transformers TR1 and TR2 by 2026
- 9 x22kV Isolators by 2023
- 2 x 22kV Protection Relays by 2026

Based on a Condition Based Risk Management (CBRM) analysis, the following have been deemed to be problematic:

- 4 x 66kV Duoroll Isolators
- 2 x 66kV Fault Throw Switches
- Porcelain Surge Arresters

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

Four potentially feasible options have been investigated:

- Option 1: Replace 1 x transformer, install NOMAD connection points and remove KAGA fault disruption
- Option 2: Replace 1 x transformer and install NOMAD connection points
- Option 3: Replace 2 x transformers and remove KAGA fault disruption
- Option 4: Replace 1 x transformer, run 1 x transformer to failure and remove KAGA fault disruption

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 3 – to replace 2 x 4MVA transformers with two new 6.3MVA 66/22kV transformers and install two 66kV fuses and 36kV reclosers to provide transformer protection at Mount Garnet Substation. A 100m feeder will be installed at the 33kV 3MTG tee point between MOGA and KAGA to cut in and out of MOGA as well as a 66kV circuit breaker.

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 Mount Garnet 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:

- Provides background information on the network capability limitations of the distribution network supplying the Mount Garnet 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.

1.2. 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 that involves replacing 2 x 4MVA 66/22kV transformers with two brand new 6.3MVA 66/22kV transformers. Two 66kV fuses and 36kV reclosers will be installed to provide protection for both transformers. A 100m feeder will be installed at the 66kV 3MTG T point between MOGA and KAGA to cut the feeder in and out of MOGA as well as a 66kV circuit breaker at Mount Garnet 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

Mount Garnet Zone 66/22kV Substation (MOGA) is located north-west of the Atherton Tablelands and is supplied by one incoming 66kV feeder (3MTG) from Atherton Zone Substation (ATHE). On 3MTG, there is also a tee-off to Customer Substation (KAGA). MOGA provides electricity supply, via two 4MVA transformers and two 22kV transformers, to approximately 533 customers, of which 72% are residential and 28% are commercial and industrial, with a peak load of 2.4 MVA. The geographical location of Ergon Energy's sub-transmission network and substations in the area is shown in **Figure 1**.

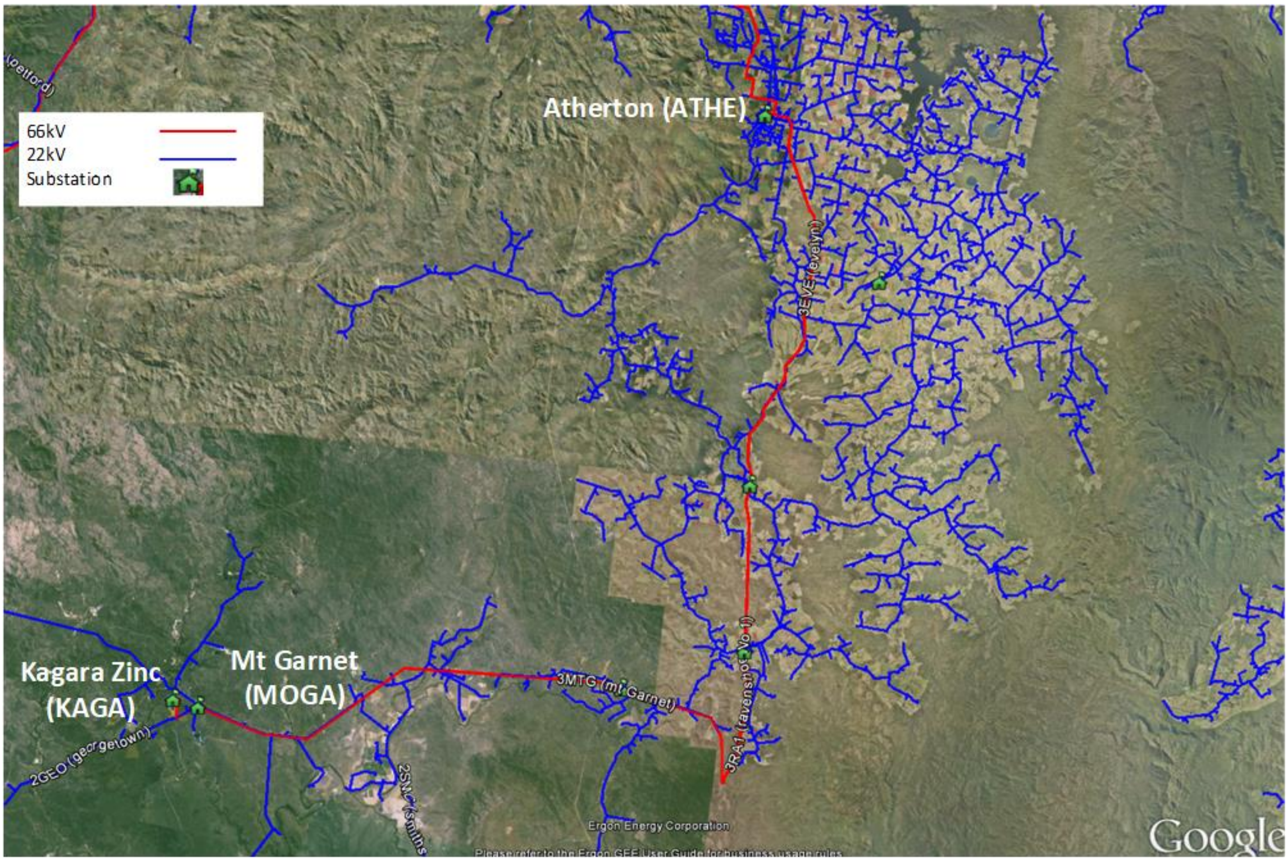


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

Mount Garnet Zone Substation (MOGA) is supplied by one incoming 66kV feeder (3MTG) from Atherton Zone Substation (ATHE).

A schematic view of the existing sub-transmission network arrangement is shown in **Figure 2** and the geographic view of Mount Garnet substation is illustrated in **Figure 3**. **Figure 4** shows the existing schematic of Mount Garnet substation.

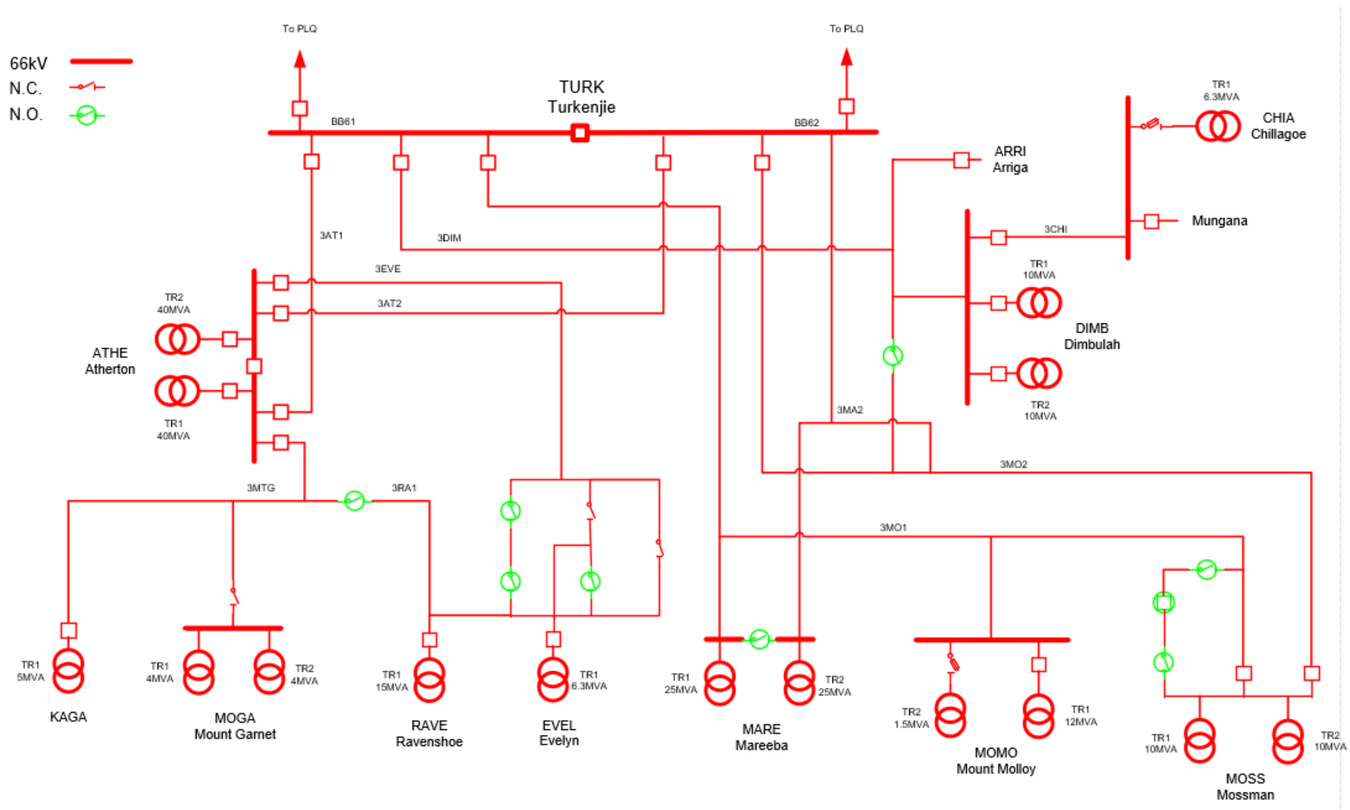


Figure 2: Existing network arrangement (schematic view)

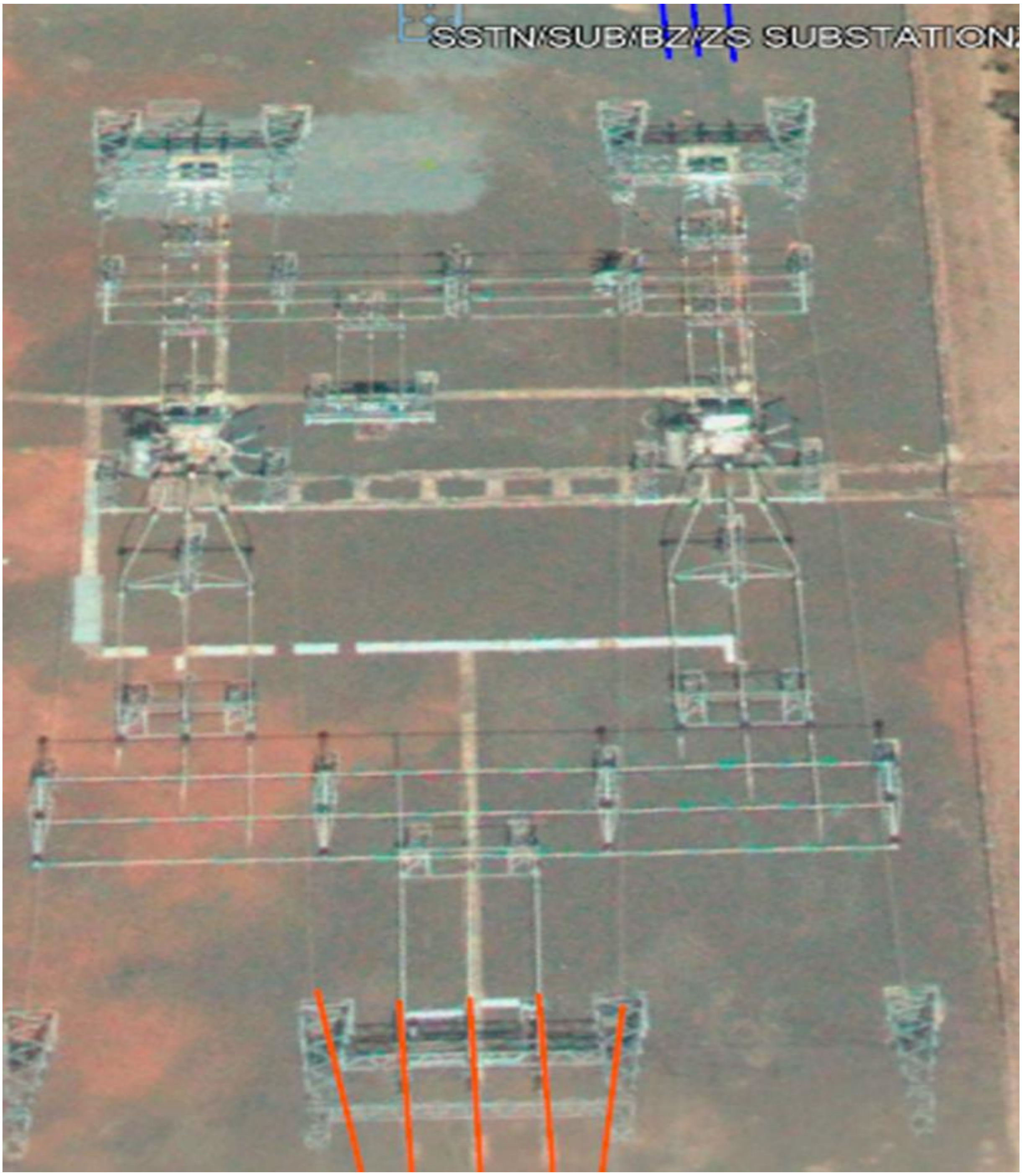


Figure 3: Mount Garnet Substation (geographic view)

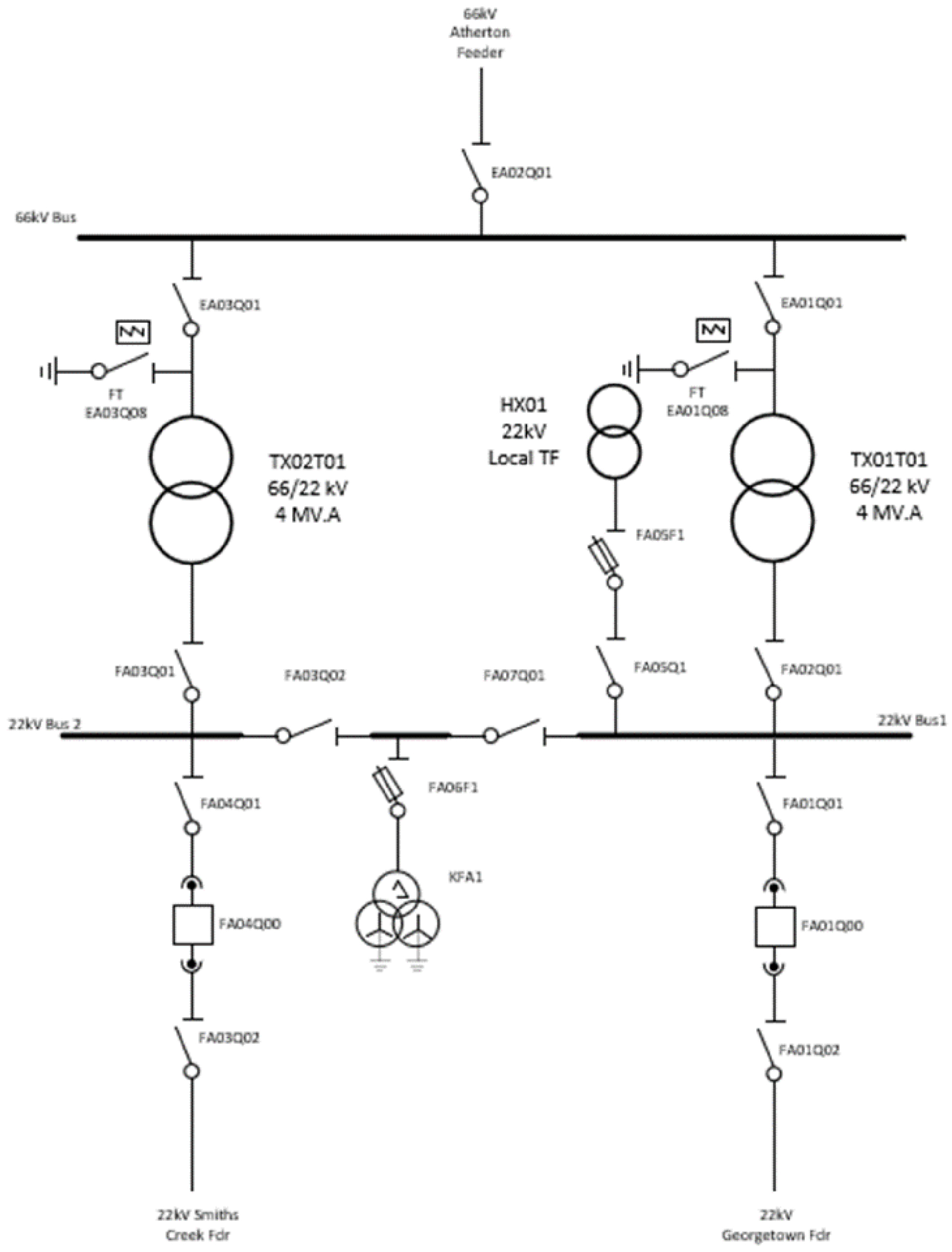


Figure 4 Existing MOGA substation (schematic view)

2.3. Load Profiles / Forecasts

The load at Mount Garnet substation comprises a mix of residential and commercial/industrial customers of which 87% are residential and 13% are commercial and industrial.

2.3.1. Full Annual Load Profile

The full annual load profile for Mount Garnet substation over the 2021/22 financial year is shown in **Figure 5**. It can be noted that the peak load occurs during summer.

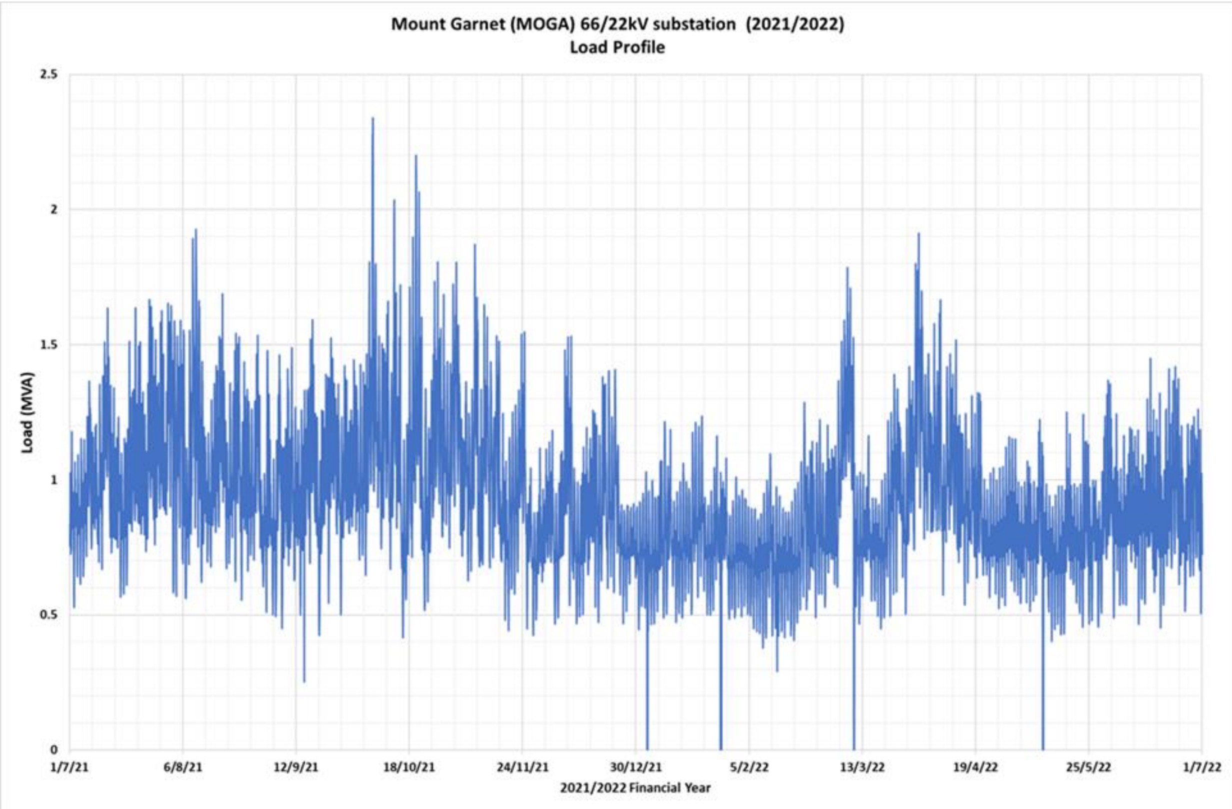


Figure 5: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Mount Garnet substation over the 2021/22 financial year is shown in **Figure 6**.

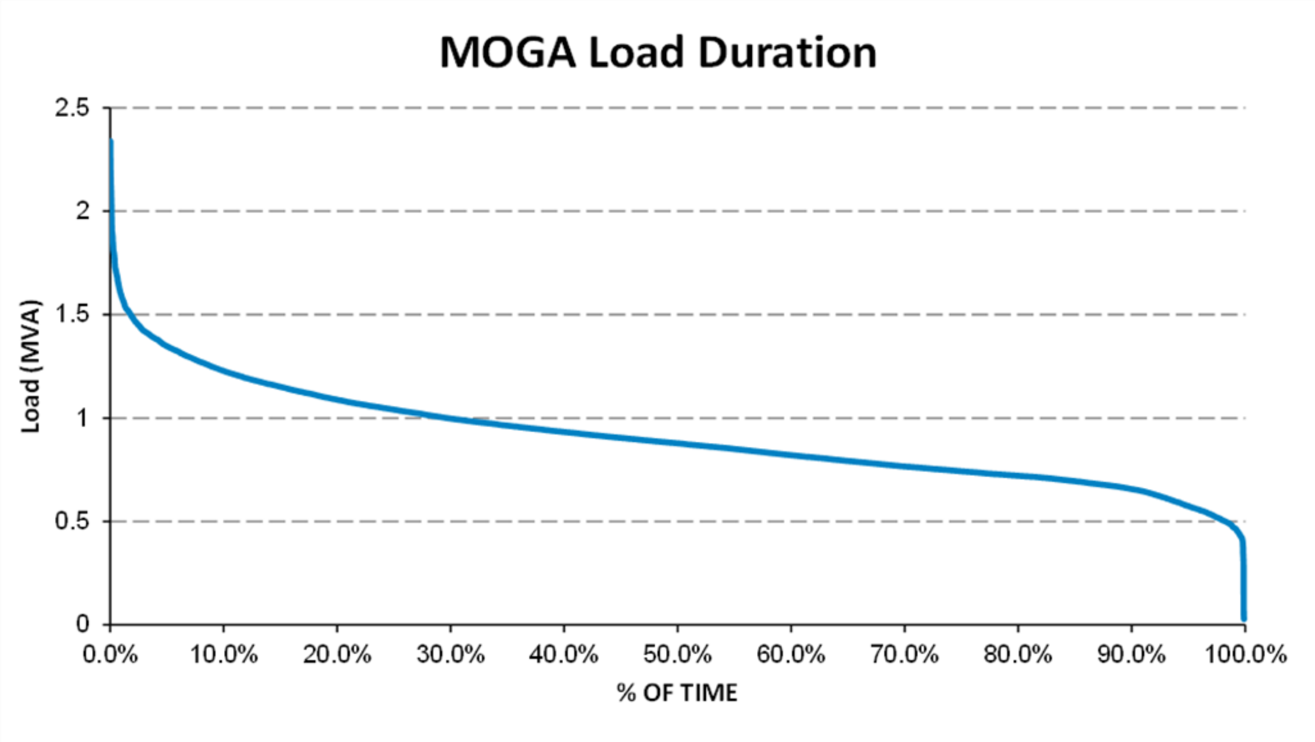


Figure 6: Substation load duration curve

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 7**. It can be noted that the summer peak loads at MOGA substation are historically experienced in the late afternoon and evening.

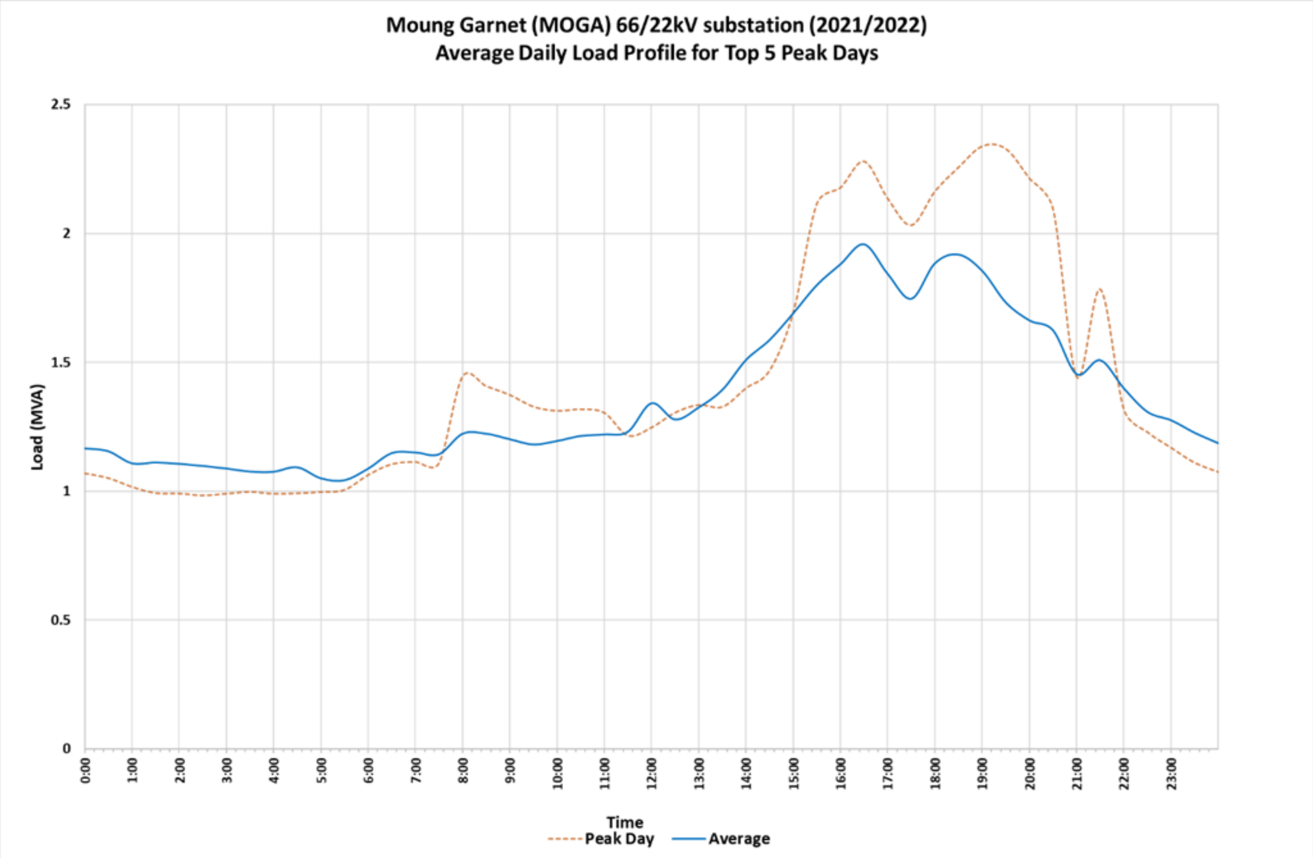


Figure 7 Average Daily Load Profile for Top 5 Peak days

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 8.** 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. It can also be noted that the peak load is forecast to increase slightly over the next 10 years under the base case scenario.

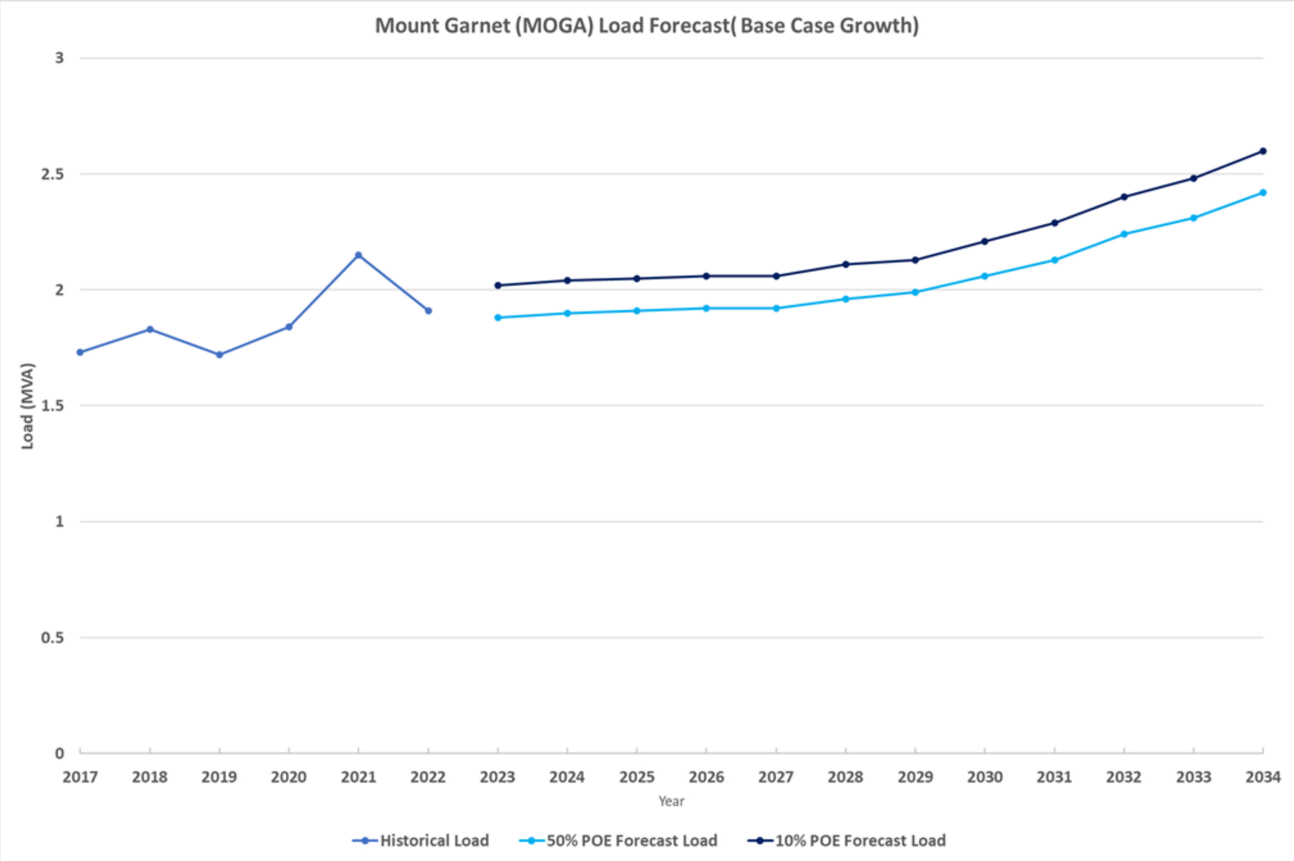


Figure 8: Substation base case load forecast

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 9**. With the high growth scenario, the peak load is forecast to increase over the next 10 years.

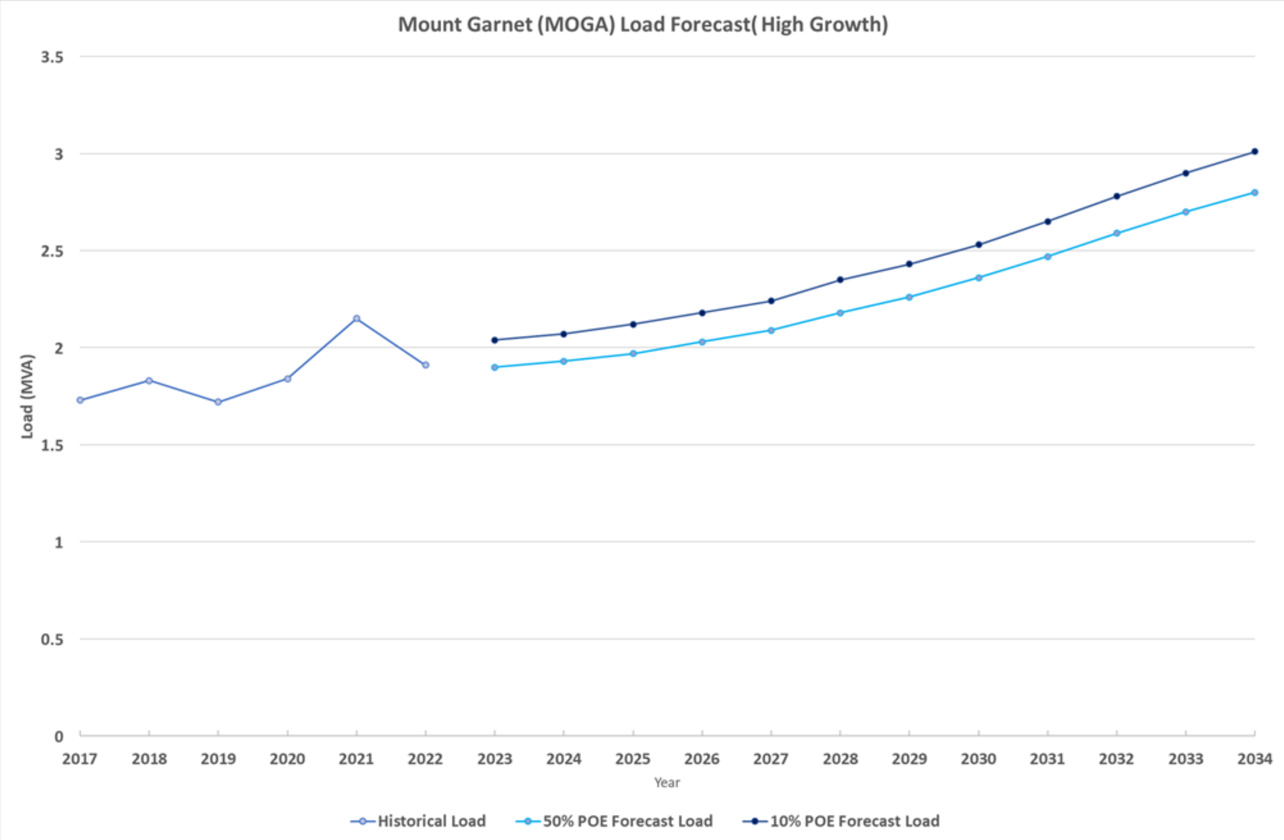


Figure 9: Substation high growth load forecast

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 10**. With the low growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

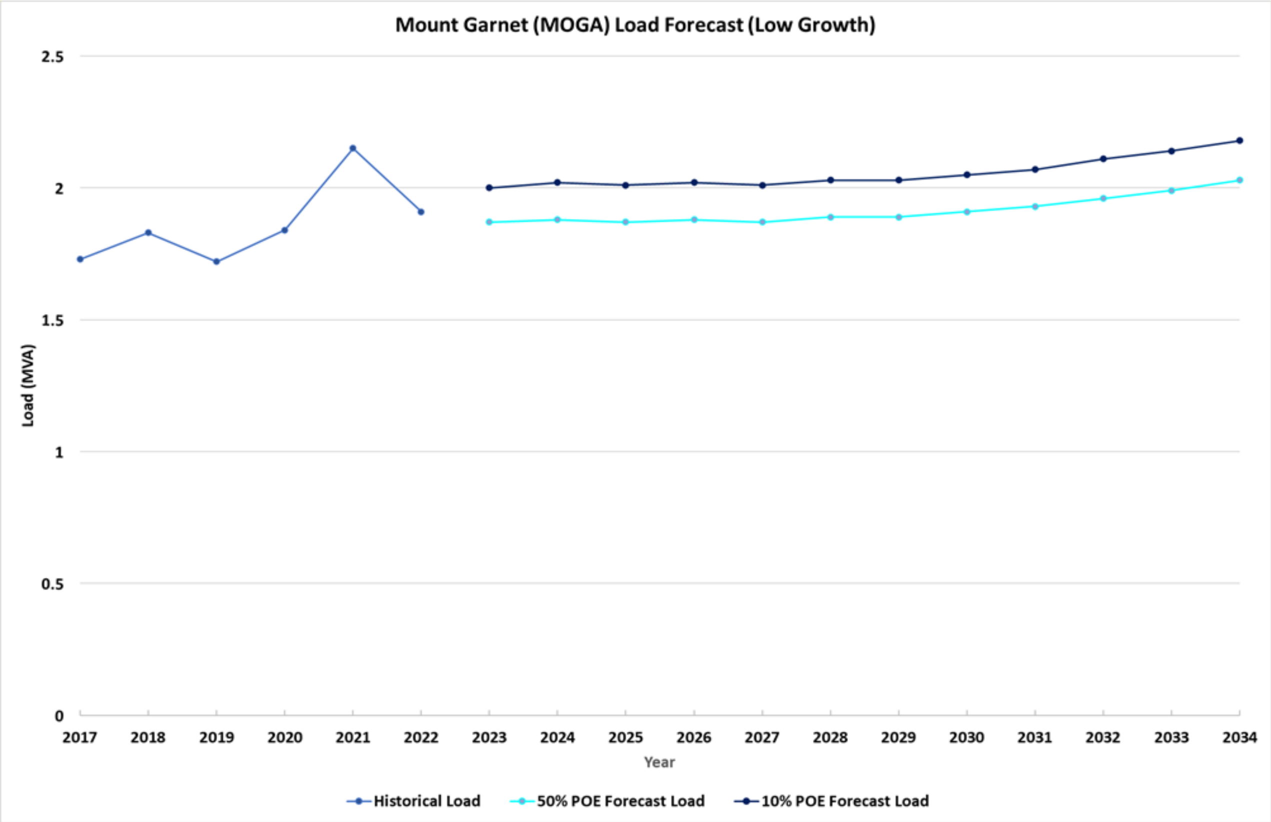


Figure 10: Substation low growth load forecast

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.

Based on a Condition Based Risk Management (CBRM) analysis, the following have been deemed to reach their retirement age:

- 66/22kV 4MVA Transformers TR1 and TR2 by 2026
- 7x 22kV Isolators by 2023
- 2 x 22kV Protection Relays by 2026

and

Based on a Condition Based Risk Management (CBRM) analysis, the following have been deemed to be problematic:

- 4 x 66kV Duoroll Isolators
- 2 x 66kV Fault Throw Switches
- Porcelain Surge Arresters

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 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. 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 Mount Garnet substation. 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. Reliability

The Kagara substation (KAGA) supplies the mine site that is currently owned by a customer. This site is fed from ATHE via a tee-off point to MOGA on 66kV 3MTG feeder.

There is a network limitation on the supply with the mine site approved for a maximum of 3.15MVA. An increase to 6.5MVA was requested however only 4.7MVA was considered. With the present protection scheme, for a fault at the customer substation or anywhere between the tee-off point to the customer substation, the 66kV breaker, EA06Q00, at ATHE will trip thus taking both MOGA and KAGA off-line as illustrated in **Figure 11.**

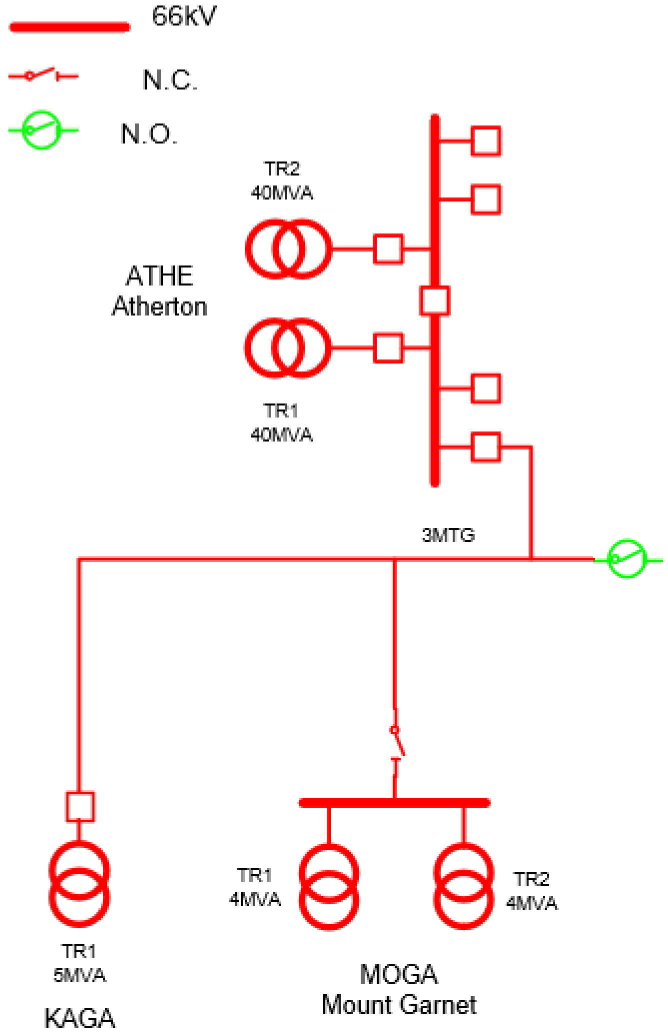


Figure 11 3MTG Tee -Off Point

This affects around 500 customers through MOGA and KAGA bulk load customer and results in a combined peak load at risk of approximately 8MVA. This network arrangement has also contributed to higher-than-average SAIDI and SAIFI for the distribution feeders than is generally expected for a short rural network.

3.2. Quantification of the Identified Need

3.2.1. 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 two 66/22kV power transformers, seven 22kV isolators and most of the protection relays at Mount Garnet substation are reaching end of life. Additionally, four 66kV Duoroll isolators, two 66kV fault throw switches and porcelain surge arresters have been deemed problematic. 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 and catastrophic failure of the power transformers and isolators. 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. 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 Mount Garnet substation. 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.

3.2.2. Reliability

System Average Interruption Duration Index (SAIDI), means the sum of the durations of all the sustained interruptions (in minutes), divided by the customer base. Momentary interruptions (of three minutes or less) are excluded from the calculation of unplanned SAIDI.

System Average Interruption Frequency Index (SAIFI), means the total number of sustained interruptions, divided by the customer base. Momentary interruptions (of three minutes or less) are excluded from the calculation of unplanned SAIFI.

The three-year average network performance for the 11kV distribution feeders supplied from Mount Garnet is shown in **Table 1**.

Table 1: Feeder reliability category and performance (existing network)

Feeder	Category	Customer number	Feeder 3-year average SAIDI	Category SAIDI target	Feeder 3-year average SAIFI	Category SAIFI target
George Town	Short Rural	67	2309	424	14.7	7.4
Smith Creek	Short Rural	442	22202	964	12.8	7.4

Feeder reliability classifications are defined below:

- green feeders have a three-year average ≤ target
- yellow feeders have a three-year average > target < 150% target
- amber feeders have a three-year average > 150% target < 200% target

- red feeders have a three-year average > 200% target.

3.2.3. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for each credible option which includes calculating the value of customer reliability (VCR) and cost of emergency replacement (ERC), safety and customer generation curtailment cost (CECV). Figure 12 shows the benefits of Option 2 (section 4.3) in comparison to the counter-factual, which in this case is continuing the use of the existing plants and maintenance and operation. The large positive VCR benefits are attributed to the expected decrease in plant failure rate after the proposed asset replacement in 2026.

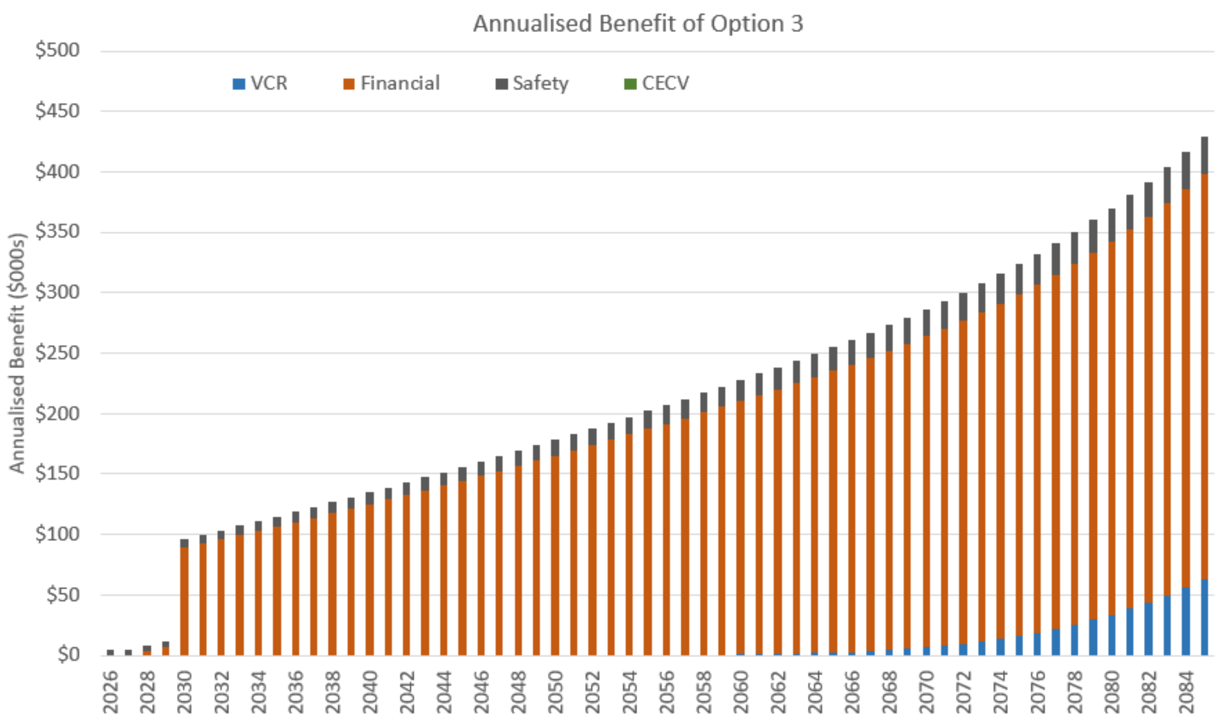


Figure 12: Annualised Benefits of Option 3 compared with Counter-factual

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 Mount Garnet substation will be consistent with the base case forecast outlined in Section 2.3.4.

Factors that have been considered 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)
- 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 four credible network options that will address the identified need.

4.1.1. Option 1: Replace 1 x transformer, install NOMAD connection points, and remove KAGA fault disruption

This option involves replacing one 4MVA 66/22kV transformer with a brand new 6.3MVA 66/22kV transformer. A 66kV fuse and 36kV recloser will also be installed to provide transformer protection. The other 4MVA 66/22kV transformer will be removed and replaced with NOMAD mobile substation connection points. A new access road will be established to cater for the NOMAD mobile substation. A 100m long feeder will be installed at the 66kV 3MTG tee point between MOGA and customer substation to cut the feeder in and out of MOGA as well as the installation of 66kV circuit breaker. The schematic diagram of the proposed network arrangement for Option 1 is shown in **Figure 13.**

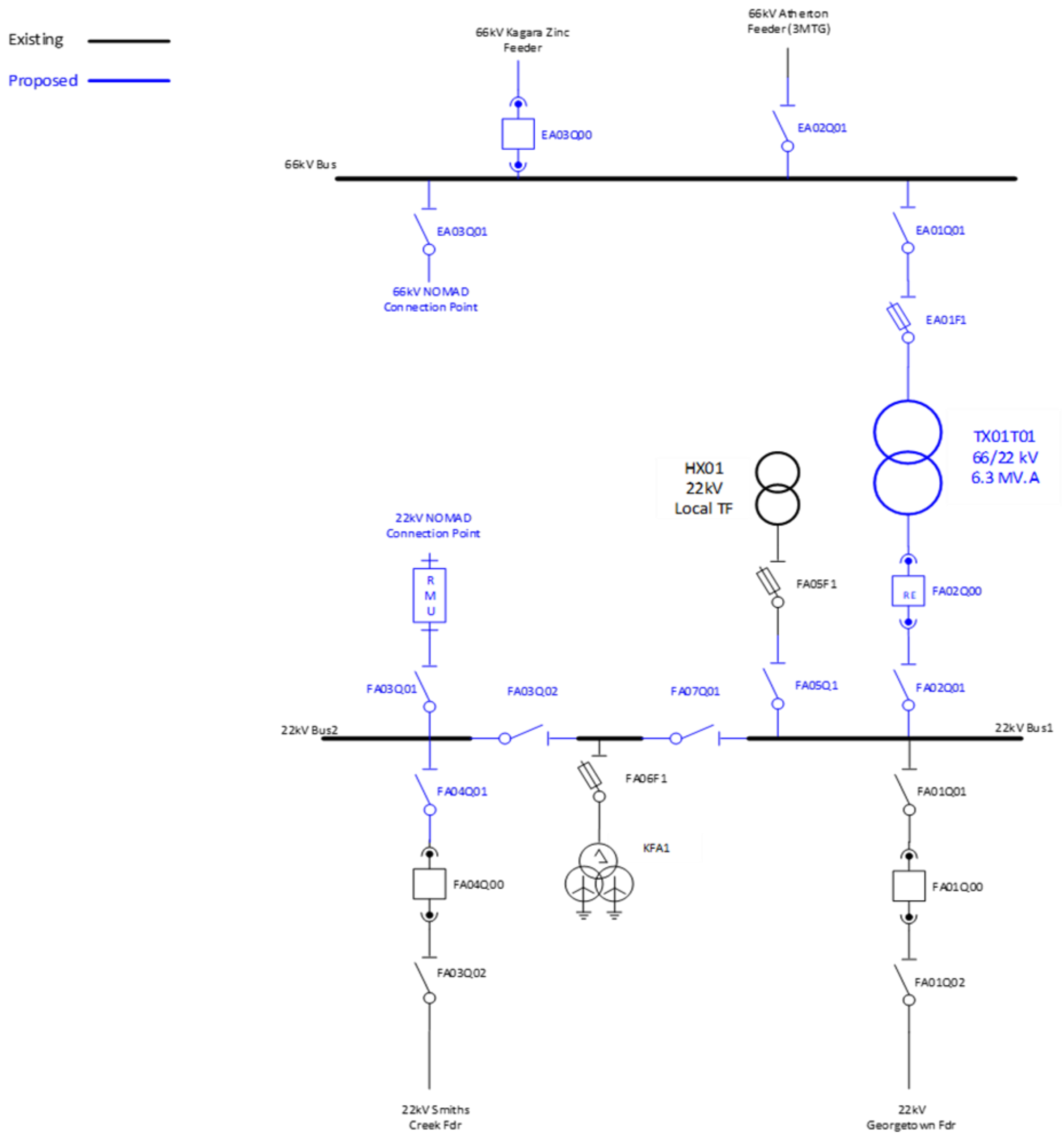


Figure 13 Option 1 proposed network arrangement (schematic view)

4.1.2. Option 2: Replace 1 x transformer and install NOMAD connection points

This option involves replacing 1 x 4MVA 66/22kV transformer with a brand new 6.3MVA 66/22kV transformer. A 66kV fuse and 36kV recloser will be installed to provide transformer protection. The other 4MVA 66/22kV transformer will be removed and replaced with NOMAD mobile substation connection points. A new access road will be established to cater for the NOMAD mobile in substation. A schematic diagram with the proposed network arrangement for Option 2 is shown in **Figure 14.**

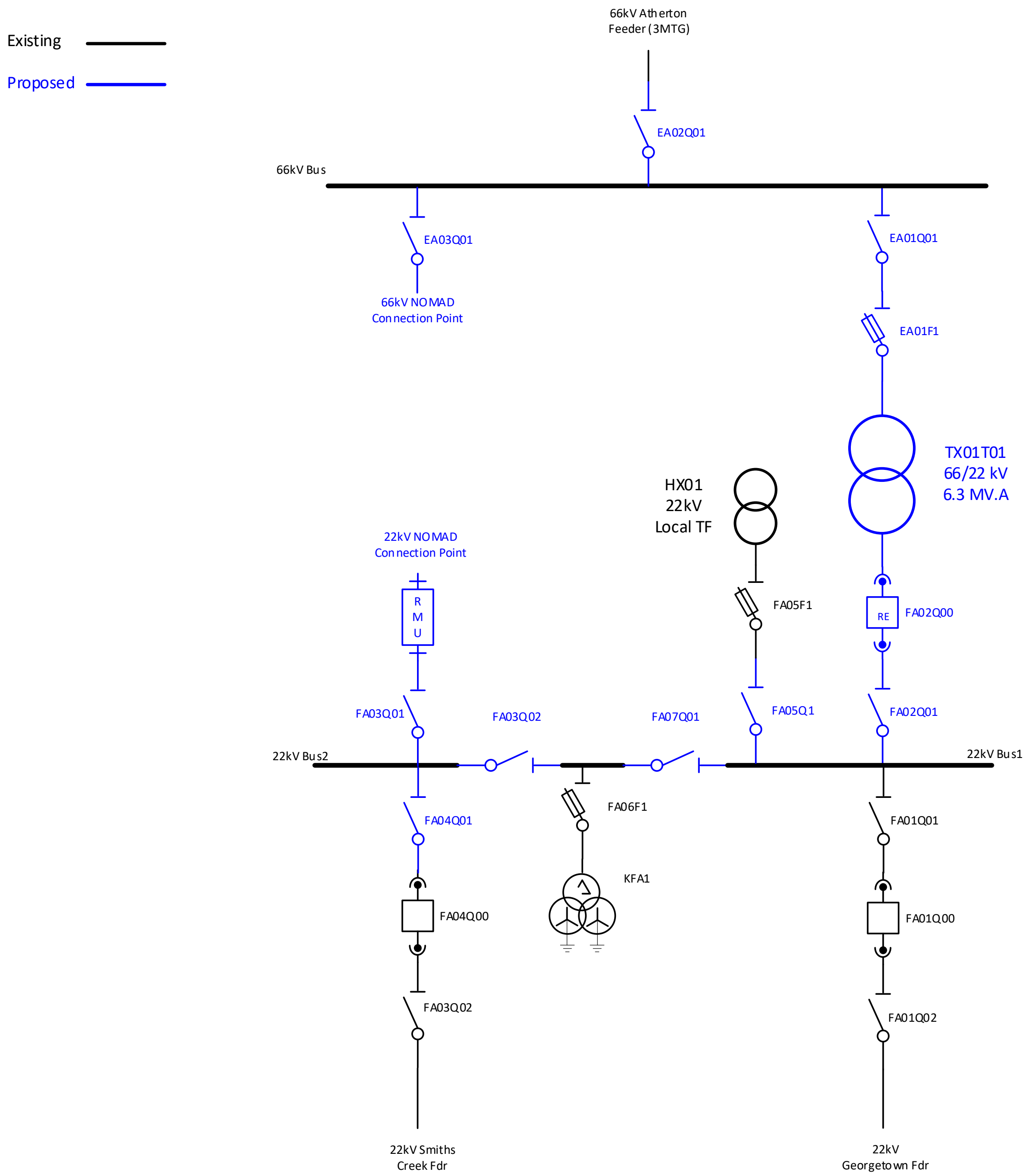


Figure 14 Option 2 proposed network arrangement (schematic view)

4.1.3 Option 3: Replace 2 x transformers and remove KAGA fault disruption

This option involves replacing 2 x 4MVA 66/22kV transformers with two brand new 6.3MVA 66/22kV transformer. Two 66kV fuses and 36kV reclosers will be installed to provide protection for both transformers. A 100m feeder will be installed at the 66kV 3MTG T point between MOGA and KAGA to cut the feeder in and out of MOGA as well as a 66kV circuit breaker. Refer **Figure 15**.

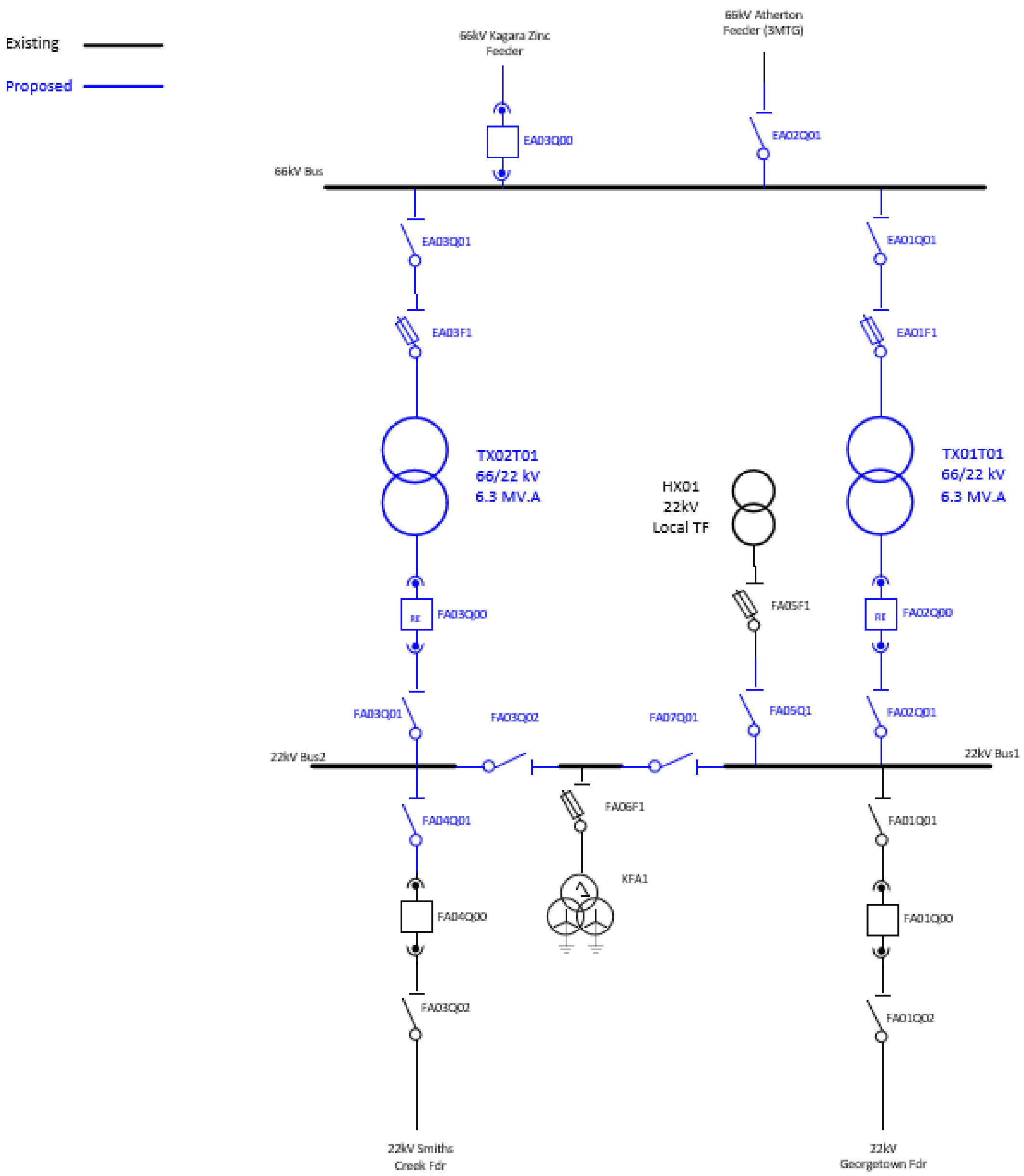


Figure 15 Option 3 proposed network arrangement (schematic view)

4.1.4 Option 4: Replace 1 x transformer, run 1 x transformer to failure and remove KAGA fault disruption

This option involves replacing 1 x 4MVA 66/22kV transformer with a brand new 6.3MVA 66/22kV transformer. A 66kV fuse and 36kV recloser will be installed to provide transformer protection. The other 4MVA 66/22kV transformer will run to failure at which point it will be replaced with either a NOMAD connection point or a new 6.3MVA transformer. A 100m feeder will be installed at the

66kV 3MTG T point between MOGA and KAGA to cut the feeder in and out of MOGA as well as a 66kV circuit breaker. **Figure** 16 provides schematic diagram for Option 4.

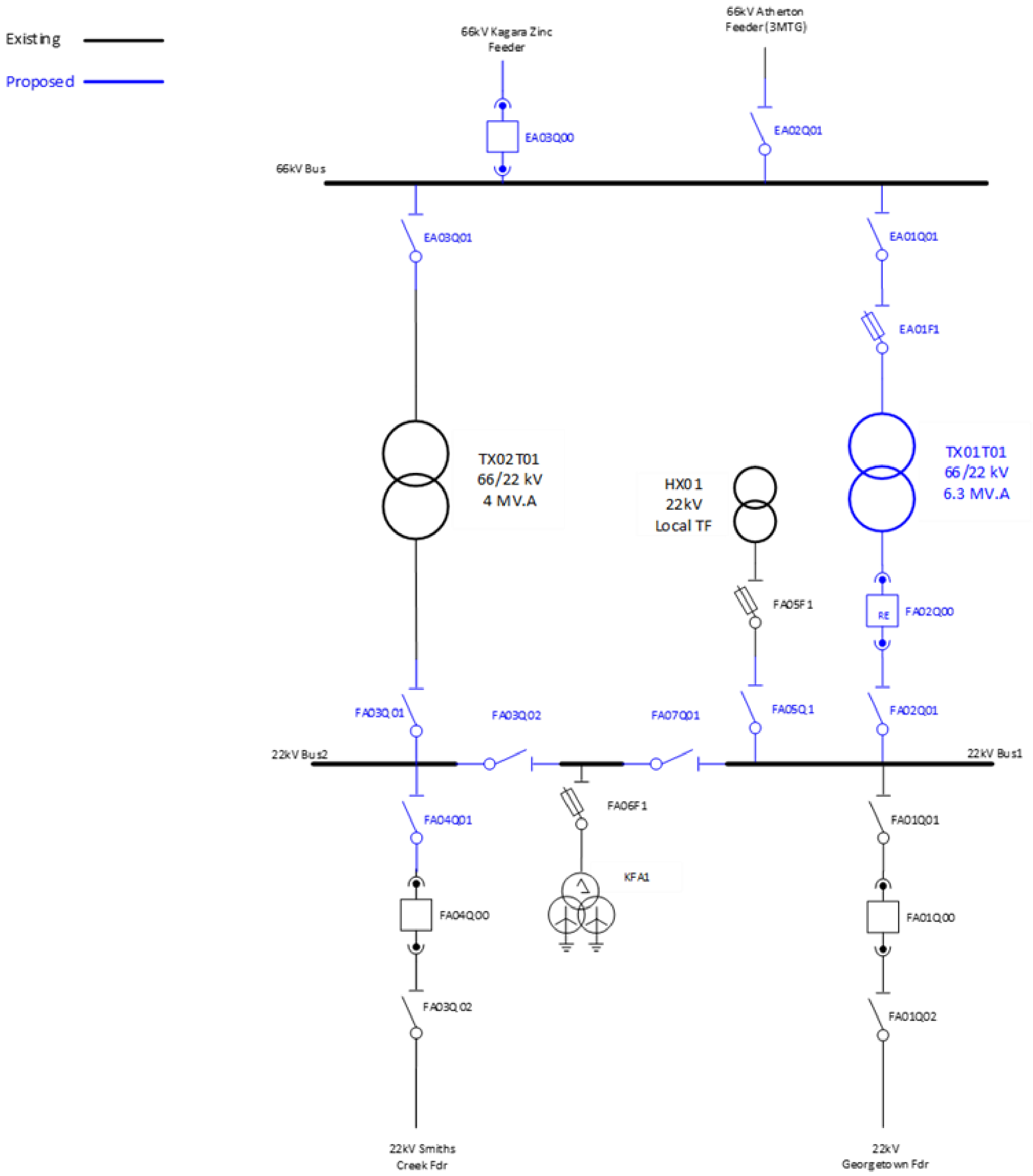


Figure 16 Option 4 proposed network arrangement (schematic view)

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 Mount Garnet customer base and considered a number of demand management technologies. Asset safety and performance risks are the key project drivers (i.e., the identified need) at Mount Garnet. It has been determined that most demand management options will not be viable propositions and have been explored in the following sections for completeness.

Network Load Control

Residential customers and some commercial loads appear to drive the daily peak demand which generally occurs between 6:00pm and 9:00pm.

There are 204 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 122.4kVA[1] is available.

Mount Garnet substation LC signals are controlled from Atherton Bulk Supply Substation (ATHE). 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 Atherton Bulk Supply Substation exceeds 24MW. This strategy does not directly address demand peaks experienced at Mount Garnet. 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

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

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 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.

Customer Solar Power Systems

A total of 94 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 676 kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 6:00pm and 9:00pm. As such customer solar generation does not coincide with the peak load period.

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

4.2.3. 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 Mount Garnet area to address the identified need.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is option 3. This option involves replacing 2 x 4MVA 66/22kV transformers with two brand new 6.3MVA 66/22kV transformers. Two 66kV fuses and 36kV reclosers will be installed to provide protection for both transformers. A 100m feeder will be installed at the 66kV 3MTG T point between MOGA and KAGA to cut the feeder in and out of MOGA as well as a 66kV circuit breaker.

Upon completion of these works, the asset safety and reliability risks at Mount Garnet substation will be addressed. 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.

The estimated capital cost of this option 3 inclusive of interest, risk, contingencies, and overheads is $6,959,893. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The target completion date for the recommended development is in June 2026.

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 and Customer Interruptions caused by Network Outages

5.1.1. 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 $36.04/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.

Customer export curtailment value (CECV) represent the detriment to all customers from the curtailment of DER exports (eg: rooftop solar PV systems). A reduction in curtailment due to implementing a credible option result 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 ad forecast to be installed within the MOGA supply area.

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
- Differences in timing of expenditure
- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in network losses
- Option value
- Other Class of Market Benefit

5.2.1. 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 MOGA area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.2. 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.

5.2.3. Differences in Timing of Expenditure

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

5.2.4. 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 MOGA area.

5.2.5. 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.

5.2.6. 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

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.

5.2.7. Other Class of Market Benefit

Ergon Energy has not identified any other relevant class of market benefit for this RIT-D.

6. DETAILED ECONOMIC ASSESSMENT

6.1. 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.

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.

[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

6.3. Net Present Value (NPV) Results

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

Option 3 shows a large positive NPV and is considered to provide the optimum solution to address the identified need and is therefore recommended development option.

Table 2: Base case NPV ranking table

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Replace 1 x transformer, install NOMAD connection points and remove KAGA fault disruption	2	$3,000,000	$8.670m	-$2.966m	-$1.705m
2	Replace 1 x transformer and install NOMAD connection points	3	$2,350,000	$7.173m	-$2.316m	-$1.027m
3	Replace 2 x transformers and remove KAGA fault disruption	1	$3,620,000	$9.525m	-$3.620m	-$1.768m
4	Replace 1 x transformer, run 1 x transformer to failure and remove KAGA fault disruption	4	$2,300,000	$5.242m	-$3,668m	-$1.785m

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 3. This option involves replacing 2x 4MVA 66/22kV transformers with a brand new 6.3MVA 66/22kV transformers. Two 66kV fuses and 36kV reclosers will be installed to provide protection for both transformers. A 100m feeder will be installed at the 66kV 3MTG T point between MOGA and KAGA to cut the feeder in and out of MOGA as well as a 66kV circuit at Mount Garnet substation.

Upon completion of these works, the asset safety and reliability risks at Mount Garnet substation will be addressed. 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.

The estimated capital cost of this option inclusive of interest, risk, contingencies, and overheads is $6.959 million. Annual operating and maintenance costs are anticipated to be 1.5% of the capital cost. The estimated project delivery timeframe has construction completed by June 2026.

7.2. Satisfaction of RIT-D

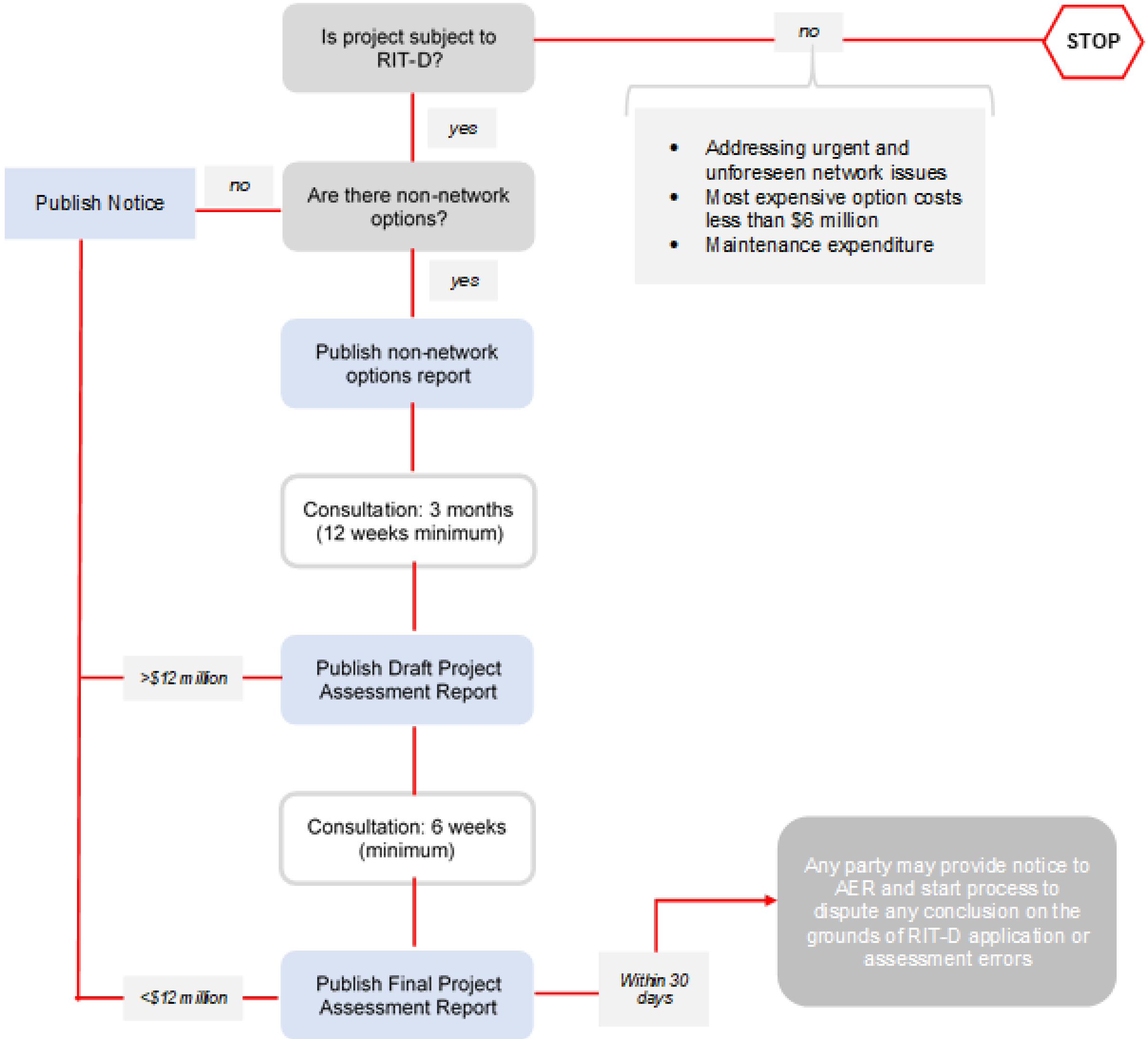
The proposed preferred option satisfies the RIT-D. This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

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 & 5
(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	5.27
(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
(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.