Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Tarampa Network Area

Final Project Assessment Report

18 September 2023

Part of Energy Queensland

EXECUTIVE SUMMARY

About Energex

Energex Limited (Energex) is a subsidiary of Energy Queensland Limited and manages the electricity distribution network in the growing region of South East Queensland which includes the major urban areas of Brisbane, Gold Coast, Sunshine Coast, Logan, Ipswich, Redlands and Moreton Bay. Our electricity distribution area runs from the NSW border north to Gympie and west to the base of the Great Dividing Range.

Our electricity network consists of approximately 54,200 kilometres of powerlines and 680,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

Identified Need

Tarampa 33/11kV zone substation (SSTRP) is located approximately 25 km North-West of Ipswich. The substation is supplied from Lockrose 110/33kV Bulk Supply Substation (SST78) via 33kV feeder F3831 and backup supply from Lowood zone substation (SSLWD) via 33kV feeder F3832. SSTRP provides electricity supply to approximately 2,150 predominately domestic customers in the surrounding suburbs.

SSTRP is equipped with two 33/11kV transformers, 33kV and 11kV outdoor switchgear and a control room.

The purpose of the project is to remove and replace aged and poor condition assets in SSTRP, this includes the 33kV duo-roll and 11kV braided vertical drop isolators, expulsive drop out fuses and 33/11kV transformer TR1. It is not possible to replace the isolators in-situ because the 11kV bus does not meet the required clearance and will require extensive staging of temporary works and generation along with staff exposure to working adjacent to energised outdoor bus.

The 33/11kV transformer TR1 has been in operation well beyond the recommended retirement year, has poor diagnostic readings and is exhibiting oil leaks.

It is proposed that the 33kV and 11kV outdoor switchgear will be replaced with new switchgear, the expulsive drop out fuses will be removed and the 33/11kV transformer will be replaced with a new transformer.

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). Energex has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the

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

Energex published a Notice of No Non-Network Options for the above-described network constrain on 14 July 2023.

Two potentially feasible options have been investigated:

- **Option A:** Replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear
- **Option B:** Remove problematic plant items, replace the 33kV and 11kV outdoor switchgear and recover 1 x 5MVA 33/11kV aged transformer, install a mobile kiosk and upgrade 11kV feeders

This Final Project Assessment Report (FPAR), where Energex 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.

Energex's preferred solution to address the identified need is Option A – Replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear.

CONTENTS

1. INTRODUCTION

This Final Project Assessment Report has been prepared by Energex 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 Tarampa network area.

In preparing this RIT-D, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Energex 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

Energex published a Notice of No Non-Network Options for the identified need in the Tarampa network area on the 14 July 2023. Energex received no responses received from stakeholders.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Tarampa area.
- Identifies the need which Energex 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 Energex 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 Energex. Dispute notifications should be sent to demandmanagement@energex.com.au

If no formal dispute is raised, Energex will proceed with the preferred option to remove problematic plant items, replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear at Tarampa substation.

1.4. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Tarampa substation provide electricity supply to approximately 2,550 predominately domestic customers in the Tarampa, Mount Tarampa, Coolan, Lowood and Clarendon areas.

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

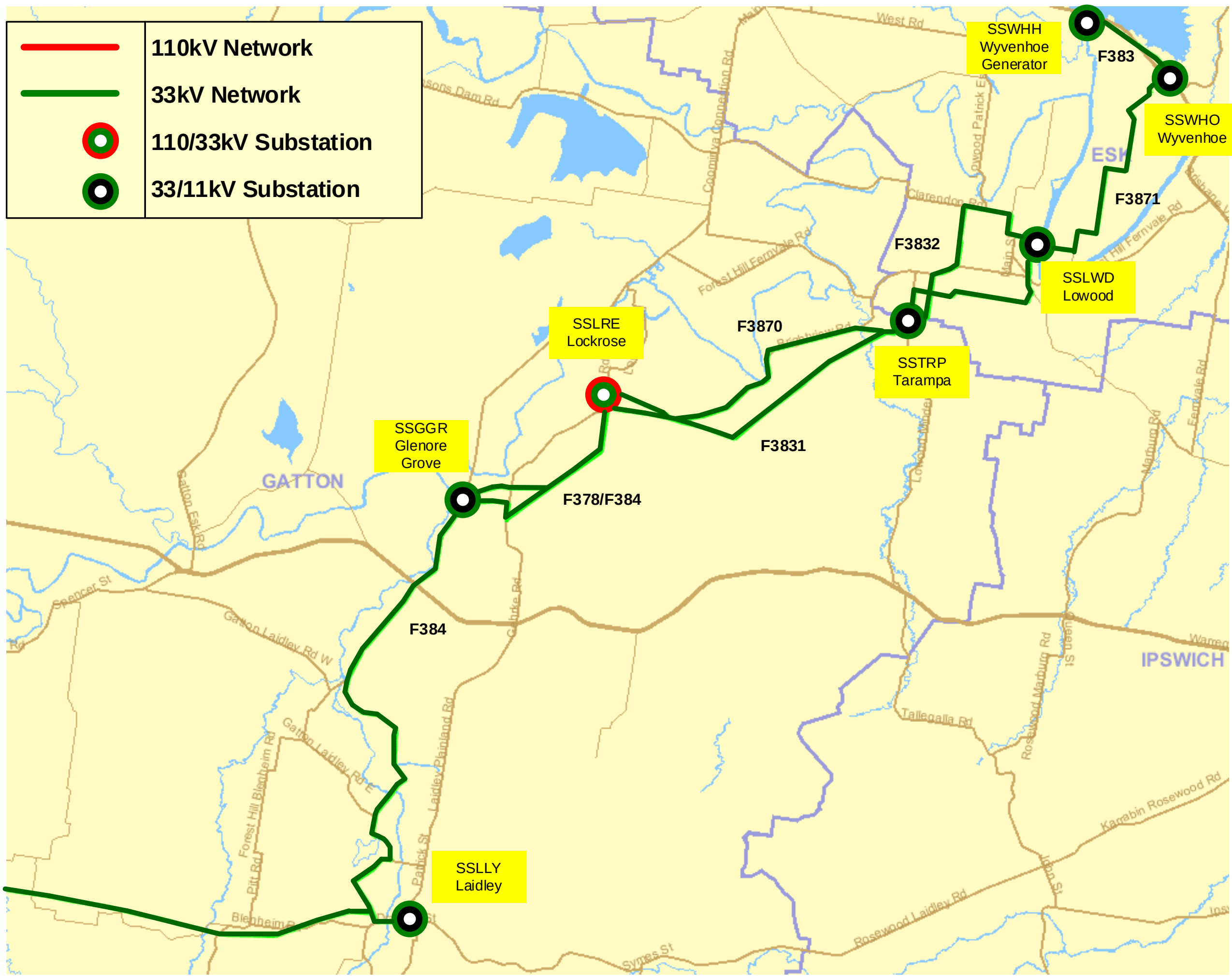


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

SSTRP is supplied from Lockrose bulk supply (SST78) via 33kV feeder F3831 and backup supply from Lowood zone substation (SSLWD) via F3832. SSLWD is connected to SST78 via a 33kV feeder F3870. The substation has an outdoor 33kV and 11kV switchgear, a control room, two 5MVA 33/11kV transformers. The 11kV bus has five active feeders which supplies a total of approximately 2,550 residential, industrial, commercial, and rural customers, with a peak of 7.5MVA based on recent summer periods.

The 33kV and 11kV bus are manually switched. The 33kV and 11kV bus contains nine 33kV isolators and ten 11kV bus isolators. The 11kV bus is operated normally open, one 33/11kV transformer supplies two 11kV feeders and other transformer supplies three 11kV feeder. The 33kV circuit breaker used for 33/11kV transformer protection and there are no 11kV circuit breakers for 33/11kV transformers.

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

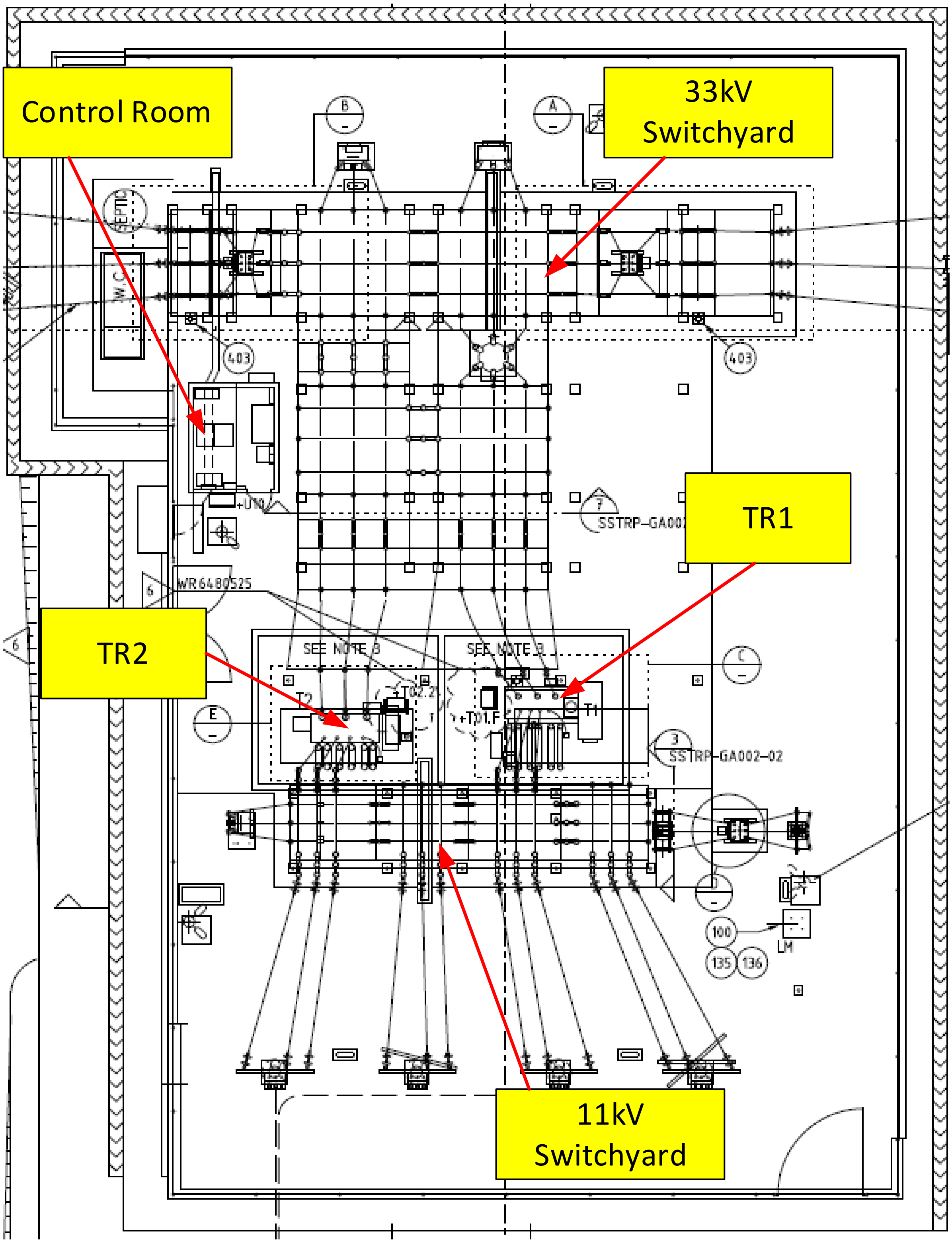

Control Room
33kV
Switchyard
TR1
TR2
11kV
Switchyard
SSTRP-GA002-02
WR 6480525
SEE NOTE 3
SEE NOTE 3
T2
T1
SEPTIC
W.C.

Figure 3.

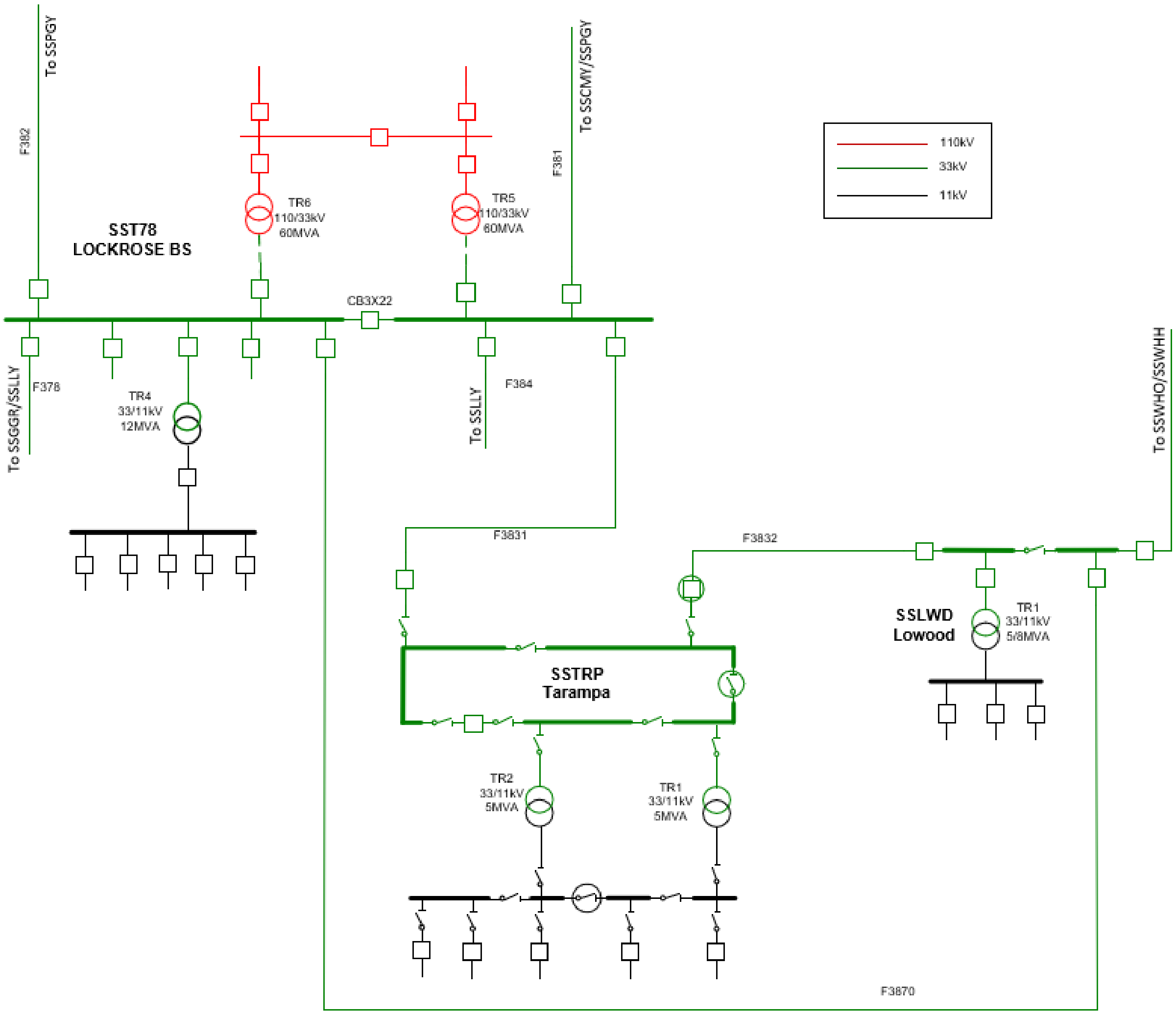


Figure 2: Existing network arrangement (schematic view)

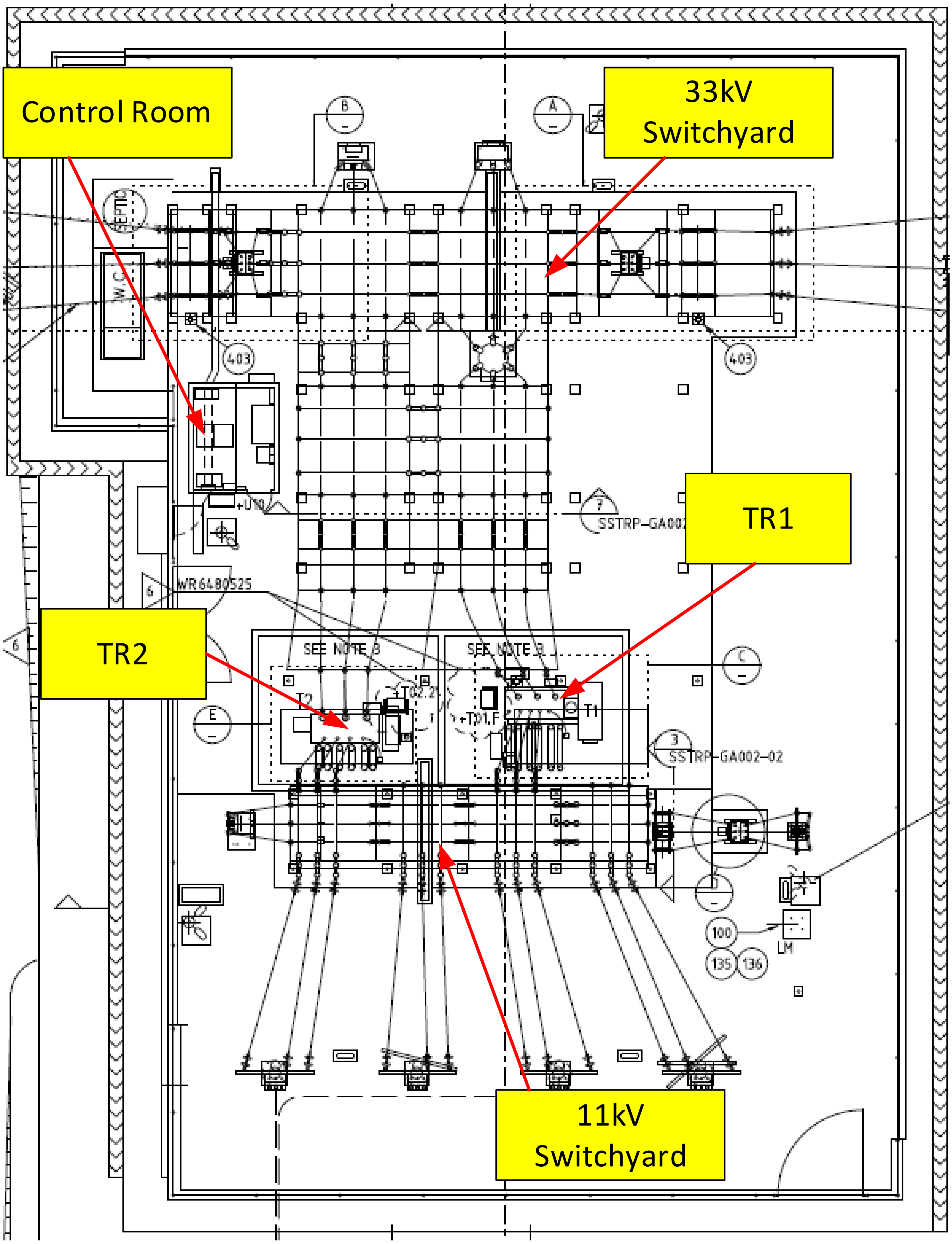


Figure 3: Tarampa Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Tarampa Substation comprises predominantly residential customers and is summer peaking.

2.3.1. Full Annual Load Profile

The full annual load profile for Tarampa Substation over the 2022/23 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

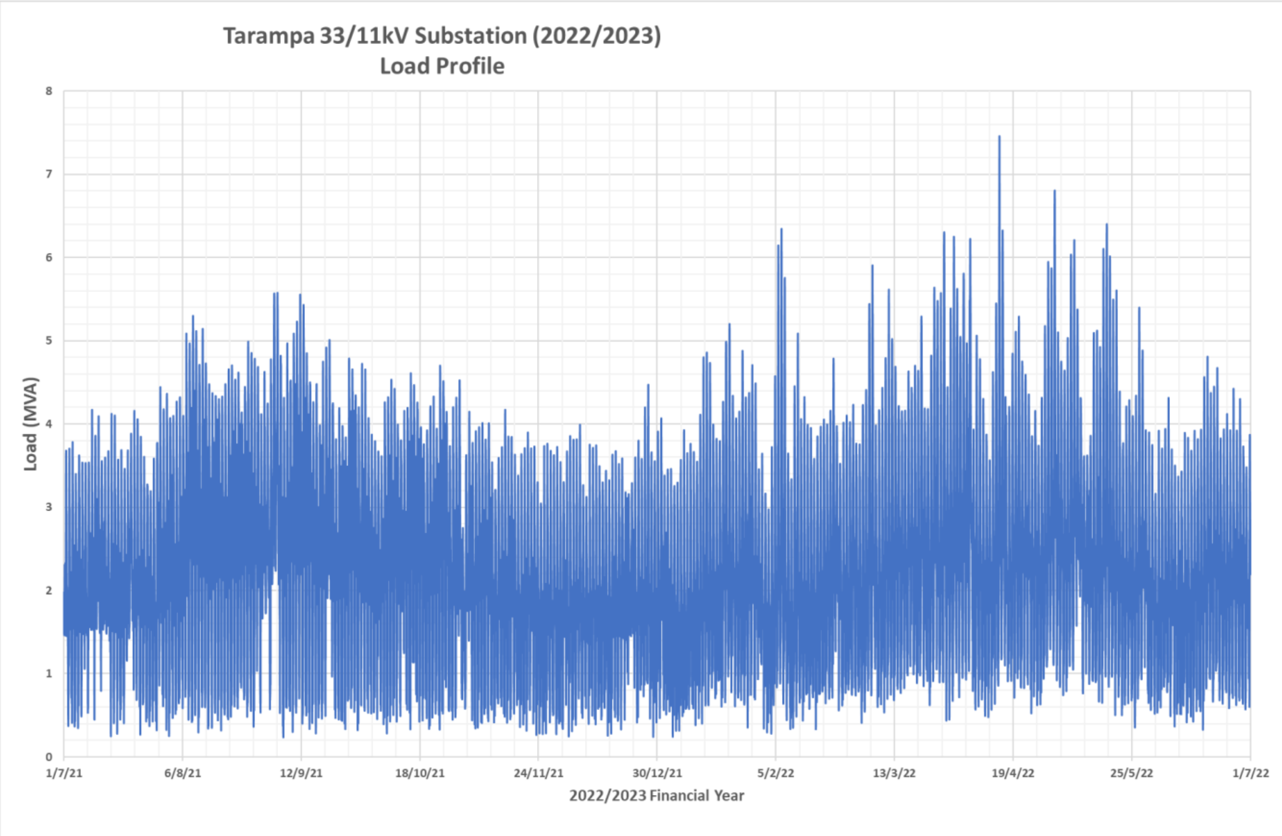


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Tarampa Substation over the 2022/23 financial year is shown in Figure 5.

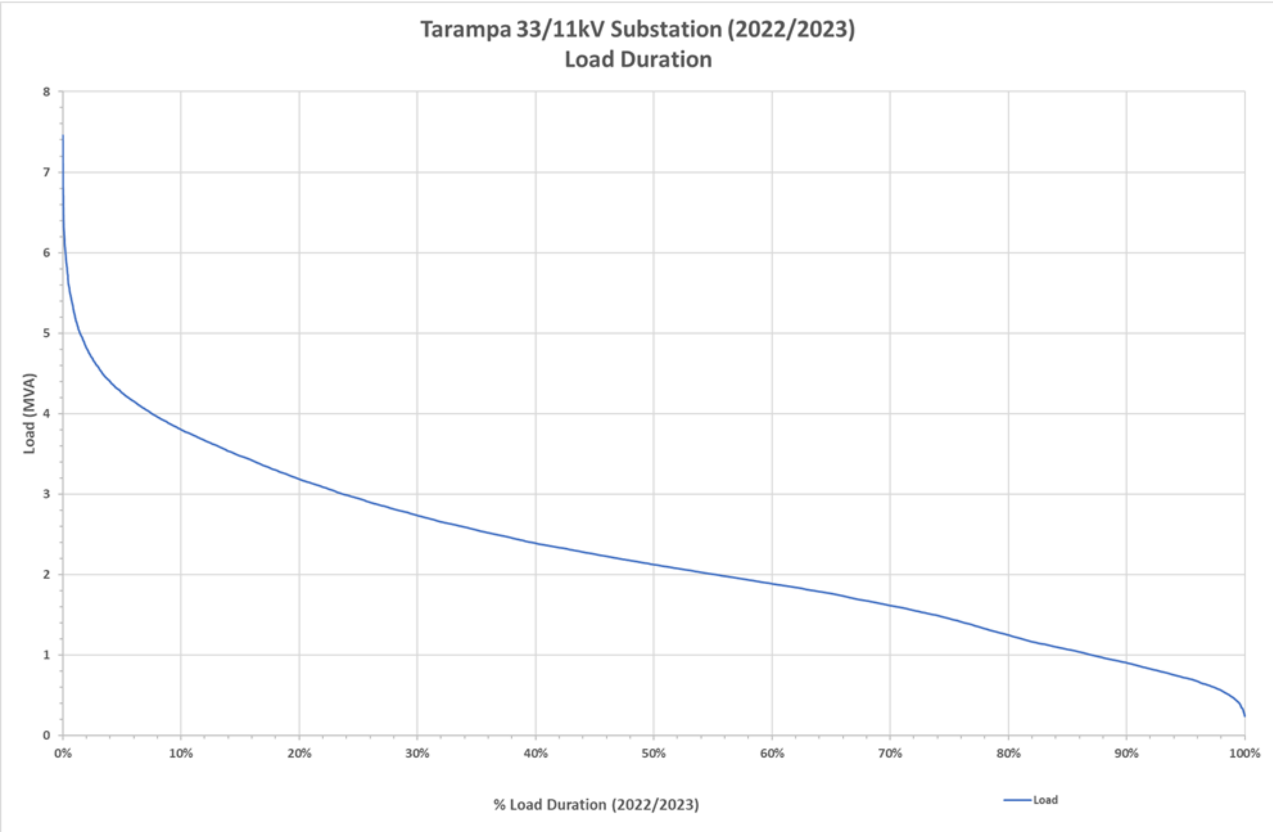


Figure 5: Substation load duration curve

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 Tarampa Substation are historically experienced in the late afternoon and evening.

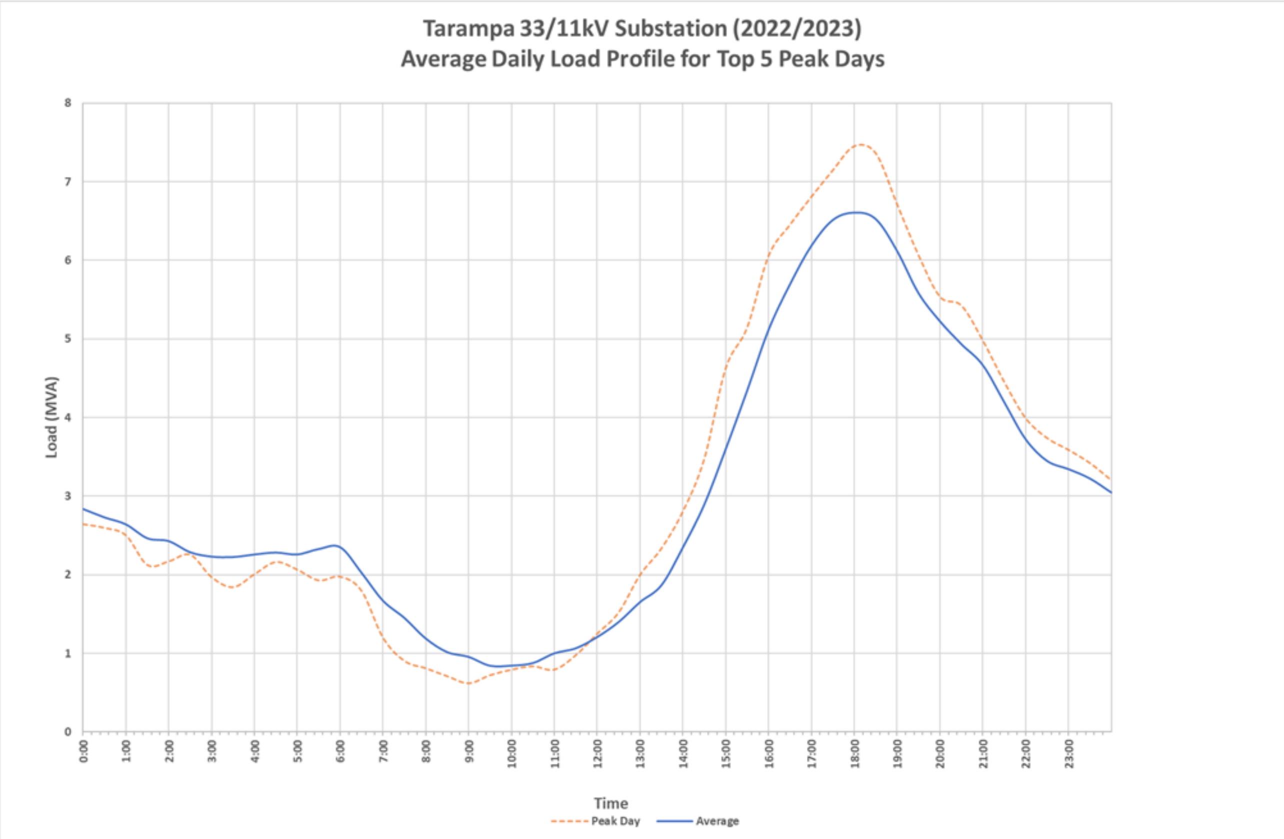


Figure 6: Substation average peak weekday load profile (summer)

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 seen that peak loads were between 6 to 9MVA for previous years prior to the recent summer peak of 7.45MVA.

The 10% POE forecast load growth in the base case scenario does not exceed the NCC rating of 13.2MVA. It can also be noted that flat growth in the peak load is forecast over the next 10 years under the base case scenario.

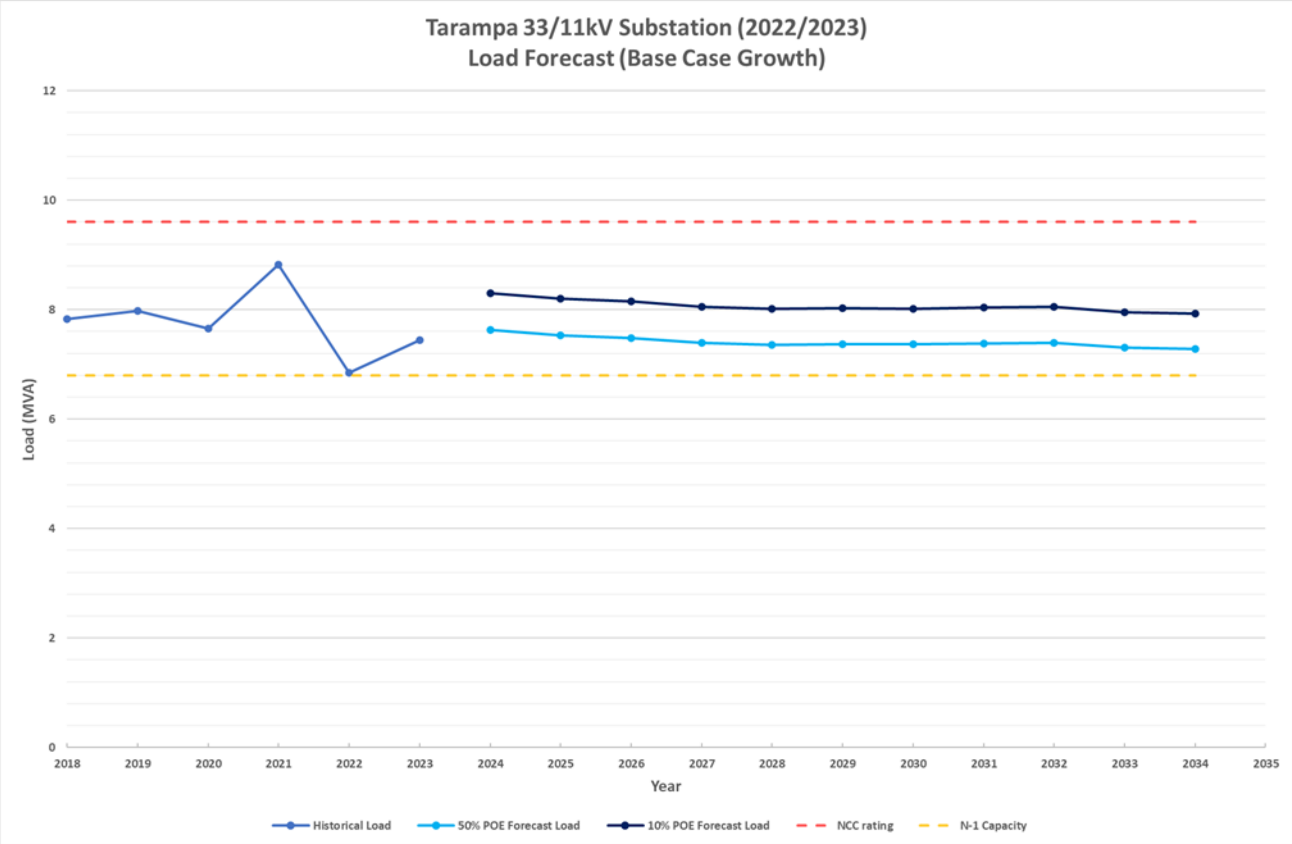


Figure 7: Substation base case load forecast

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.

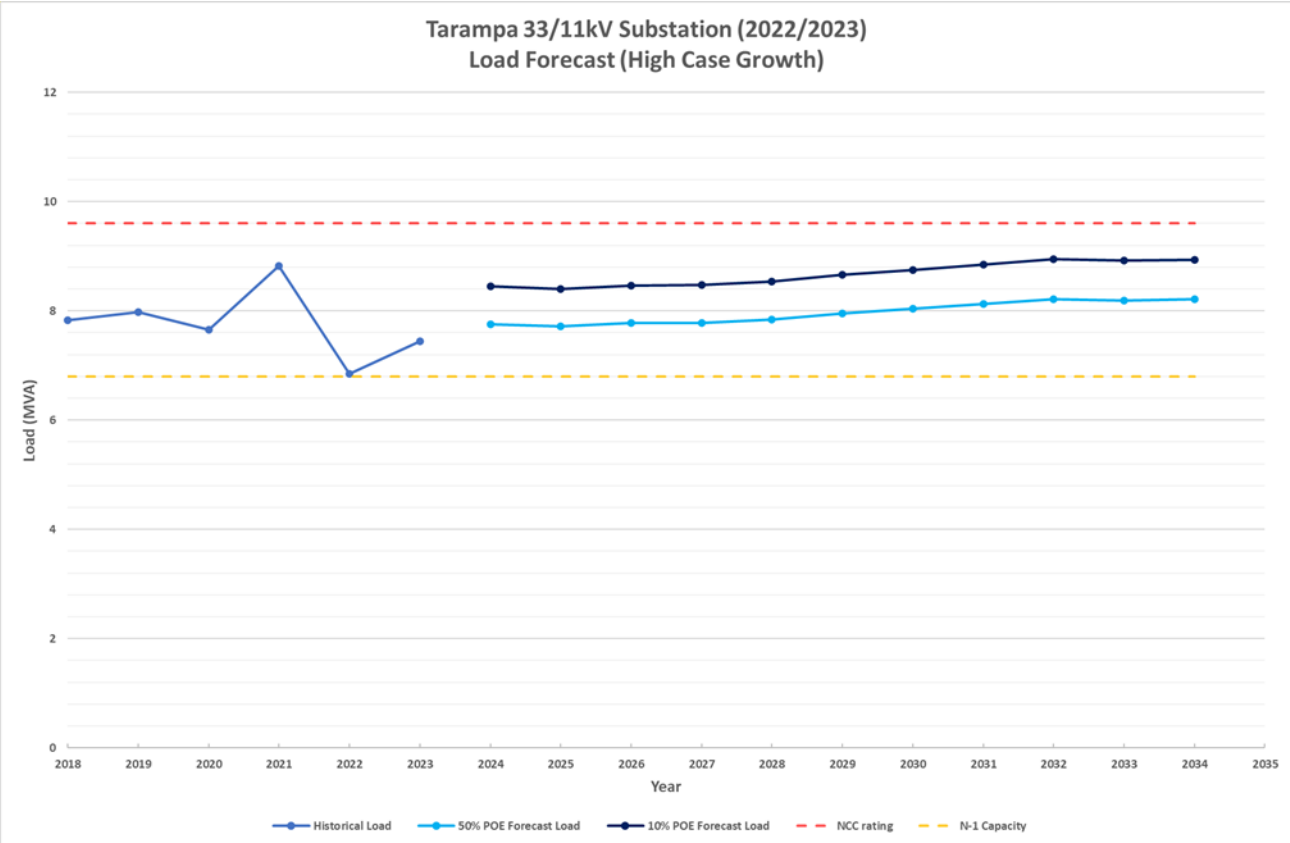


Figure 8: Substation high growth load forecast

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 slightly reduce over the next 10 years.

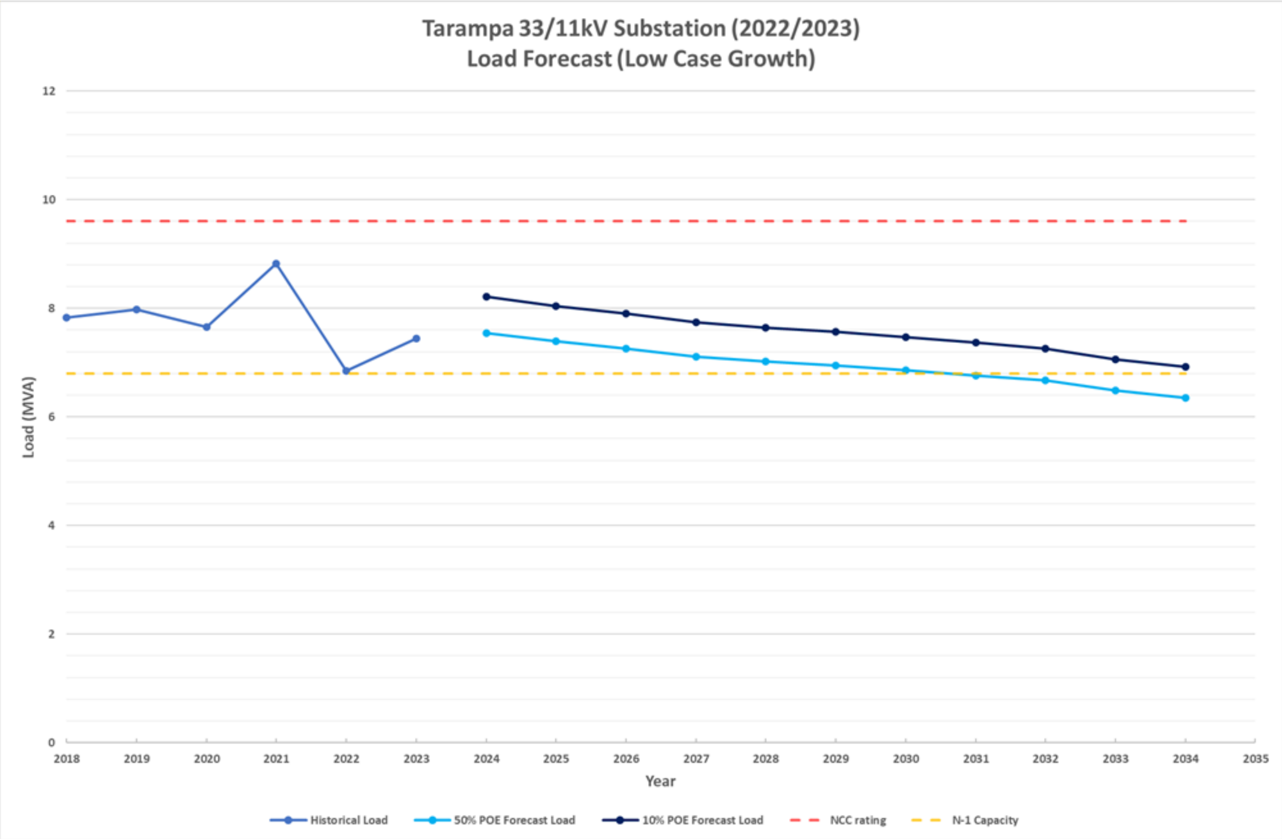


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. 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. These assets include:

- One 33/11kV transformer
- One 33kV Circuit Breaker
- Two 33kV Isolators
- Seven 11kV Isolators
- Three sets of expulsive drop out fuses
- One 33kV VT
- Two sets of 11kV Surge Arrestors
- One 11kV.433V local supply transformer
- One 30V DC battery charger

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the general public, through the increased likelihood of protection relay mal-operation. Without remediation, Energex views that the safety risk to the public and its staff to not be reduced to So Far As Is Reasonably Practicable.

Additionally, the problematic isolators and the poor condition of the assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from Tarampa Substation.

Where Energex 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

Due to the existing network configuration and deteriorated conditions of the existing substation equipment, any singular failure of the 11kV or 33kV isolator, recloser or pipework bus will result in outage to all customers supplied from Tarampa Substation. The failure of the aged 33/11kV transformer TR1 will result in outage to customers during peak times as the remaining 33/11kV transformer TR2 is not able to supply all load.

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

A recent condition assessment indicates that:

- Power transformer TR1 is aged with poor DGA and oil leaks from conservator.
- 33kV Duo-roll and 11kV braided vertical drop isolators. Field experience has revealed common issues with these units:
    - Fixed fingers tend to loosen causing high resistance and heating leading to contact annealing and loss of tension resulting in failure
    - Force of vertical operation causes hairline cracks in insulators resulting in a breakdown of the porcelain
    - Corrosion of braids.
- Expulsive drop out fuses are to be replaced to remove the hazard of expelled material
- Aged 33kV VT with leaking oil.
- Local transformer 11/.433kV is aged with poor DGA and deteriorated insulation between HV leads and transformer bushing.

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

Where Energex 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

Currently the aged assets present a risk to the reliability of supply at Tarampa. Due to the existing condition and configuration of the substation, the following reliability risk scenarios are identified:

- TR1 is assumed not to be capable of carrying load. As there are potential environmental impacts, given this transformer is expected to retire in 2026.
- TR2 5 MVA 33/11kV transformer failure – a failure of this transformer results in loss of supply of all load at SSTRP; however, it was assumed that 3 MVA load could be supplied by transfers within 3 hours, with full restoration within 12 hours.
- 11kV isolator/ recloser failure - a failure of any of these items of plant results in loss of 11kV bus and all load at SSTRP; however, it was assumed that 3 MVA load could be supplied by transfers within 3 hours, with full restoration within 4 hours.
- 33kV isolator failure – a failure of any of these items of plant would result in a loss of 33kV bus and all load at SSTRP; however, it was assumed that 3 MVA load could be supplied by transfers within 3 hours, with full restoration within 4 hours.

- 33kV or 11kV pipework outdoor bus – a failure of any of these items of plant would result in an outage to all load; however, it was assumed that 3 MVA load could be supplied by transfers within 3 hours, with full restoration within 6 hours.

3.2.3. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for Option A which includes the value of customer reliability and cost of emergency replacement. Figure 100 shows the benefits of Option A in comparison to the counter-factual, which in this case is continuing the use of the existing isolators. The benefit of this option is greater than $350,000 by 2032.

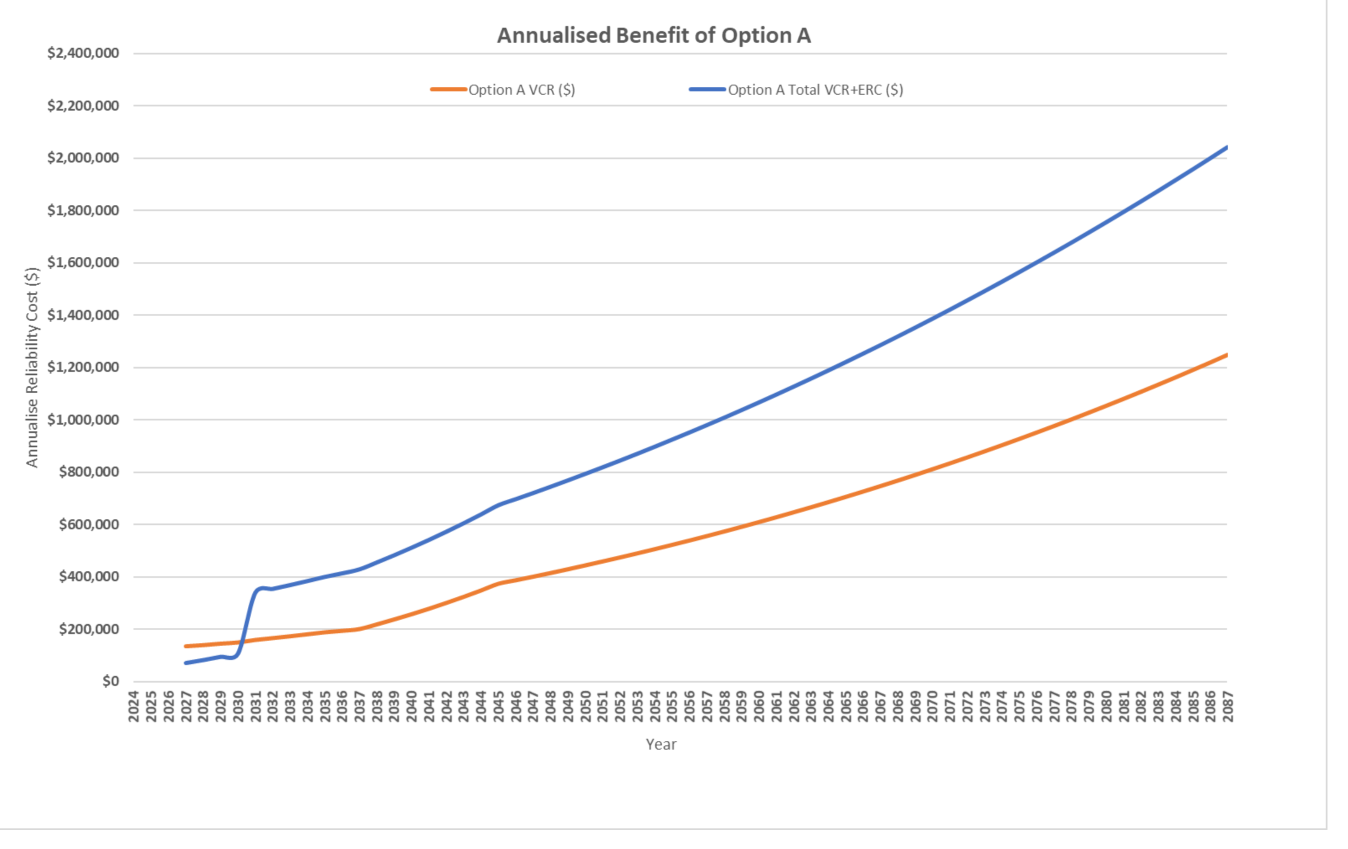


Figure 10: Annualised Benefits of Option A compared with Counter-factual

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 Tarampa 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

Energex has identified two (2) credible network options that will address the identified need. The option of replacement of the problematic and end of life assets in-situ was considered but rejected, because of the following:

- Clearance between the 11kV feeder bays is inadequate, thus, to replace the isolators most of the bus would have to be out of service. Therefore, replacement in-situ would require extensive temporary works and significant generation as there are limited load transfers available.
- In-situ replacement of disconnectors does not address existing low terminations.
- Uncertainty regarding remaining life of the galvanised steel "pipework" structures given its age and condition.
- Current contract isolators are not compatible with existing “pipework” structures.
- Sub-standard protection schemes for the outdoor bus and transformers, with inadequate space on the outdoor bus to install required CTs to deploy current standard protection schemes.
- Safety risk exposure to staff working adjacent energised outdoor bus for considerable period due to complex staging plan required to replace assets in-situ.
- Increased network risk due to longer outages required for staging.

4.1.1. Option A: Replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear

This option involves replacing TR1 with a new 5/8 MVA transformer, and also upgrading all end-of-life 33kV and 11kV outdoor switchgear in order to address the identified need.

This option involves the following works:

- Extend substation fence and earth grid to accommodate proposed construction. Leave existing substation fence to delineate construction zone from existing substation site
- Install new 33kV termination pole and install new UG 33kV section on F3832 to remove OH section from proposed construction zone
- Construct new substation building outside existing substation fence and within existing property boundary
- Construct new transformer foundation and firewalls for new 33/11kV transformer and install new transformer. Connect new bund to existing oil containment system
- Install new 33kV switchgear, 11kV switchgear and protection panels inside new substation building

- Run 33kV UG cable from new indoor switchgear to F3832 termination pole and 33kV bus-tie cable and commission.
- Run 11kV UG cable from new indoor switchgear to new transformer. Run 11kV bus-tie cable.
- Commission new TR and 11kV switchgear
- Cutover 11kV feeders to new 11kV switchgear
- Cutover 33kV F3831 to new 33kV switchgear
- Recover and scrap all existing 33kV outdoor switchgear and isolators. Recover and scrap existing 33/11kV transformer TR1
- Install new 33kV cable termination structure for TR2. Run new 33kV UG cable from 33kV switchgear to new termination structure.
- Install new 11kV cable termination structure for TR2. Run new 11kV UG cable from 11kV switchgear to new termination structure
- Recover and scrap all existing 11kV outdoor switchgear and isolators.
- Remove internal portion of substation fence

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

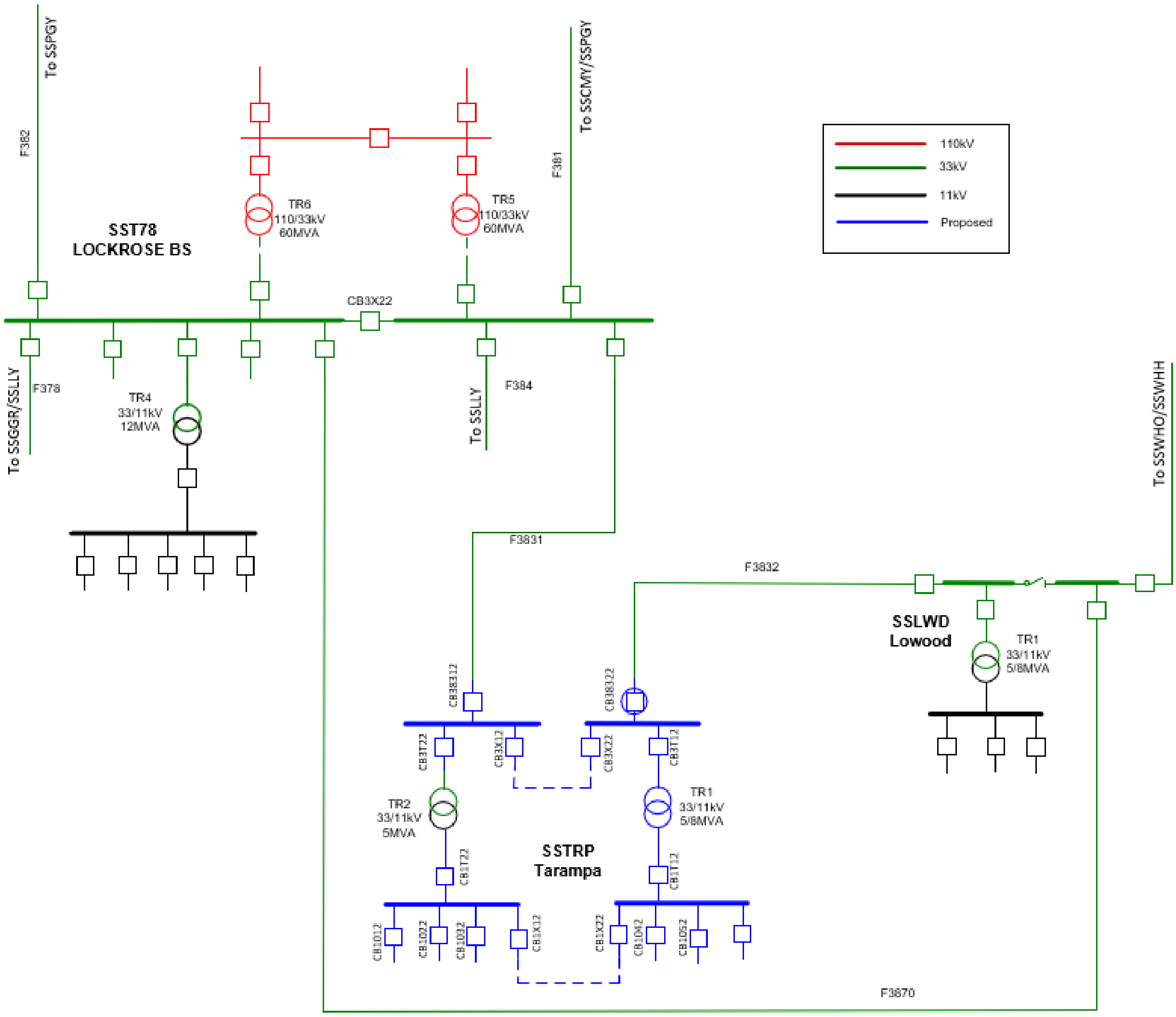


Figure 11: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Remove problematic plant items, replace the 33kV and 11kV outdoor switchgear and recover 1 x 5MVA 33/11kV aged transformer, install a mobile kiosk and upgrade 11kV feeders

This option involves the following works:

- Same as option 1 except that the 1 x 5MVA 33/11kV aged transformer would be replaced with a mobile kiosk connection and upgrade approximately 5km of 11kV feeders from Tarampa zone substation to Lowood zone substation.

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

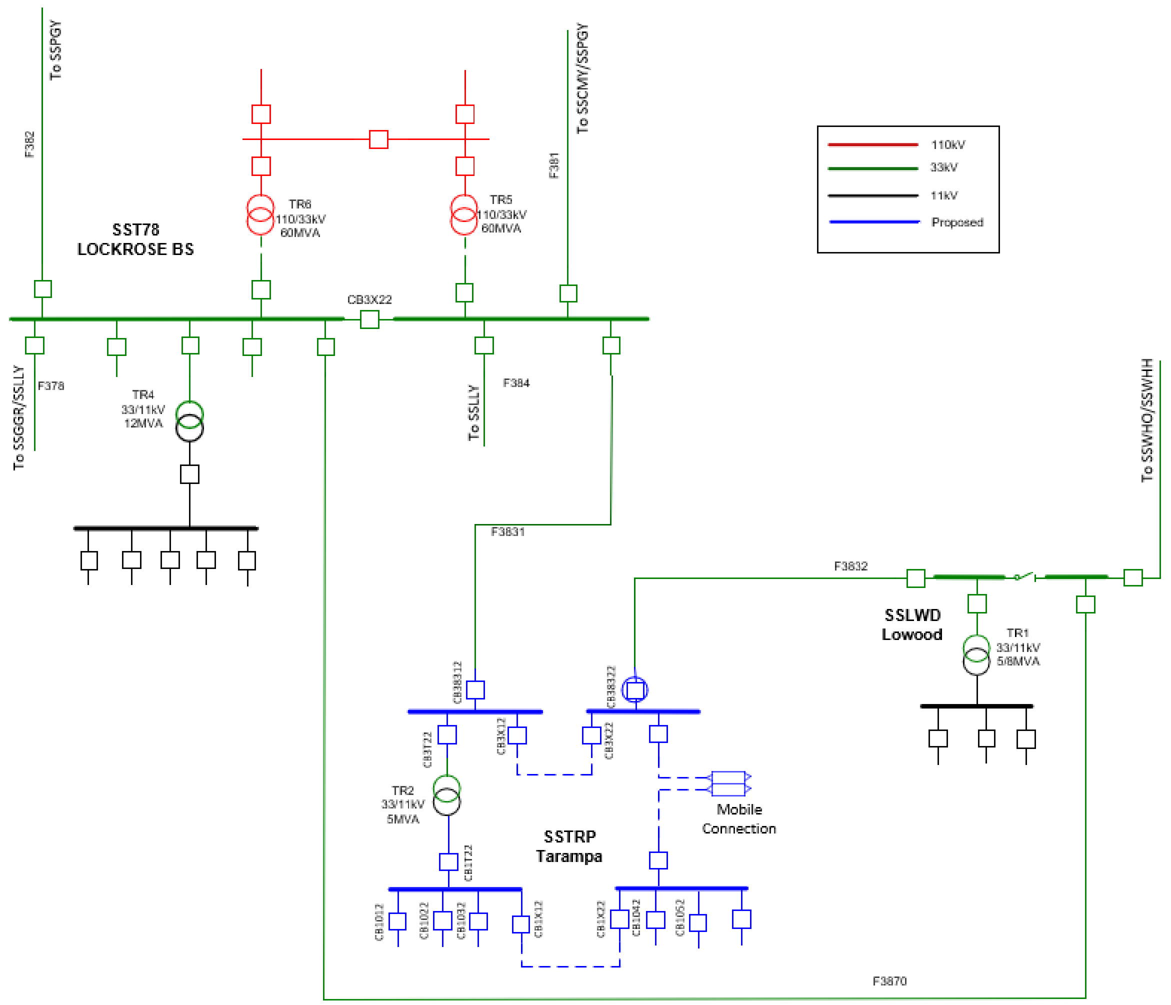


Figure 12: Option B proposed network arrangement (schematic view)

4.2. Assessment of Non-Network Solutions

Energex'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 Tarampa 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 Tarampa. 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 business customers appear to drive the daily peak demand which generally occurs between 4:00pm and 8:00pm.

There are 1058 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 391kVA[1] is available.

Tarampa Substation LC signals are controlled from T78 Lockrose Bulk Supply Substation (SST78). 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 Lockrose Bulk Supply Substation exceeds 85MW. This strategy does not directly address demand peaks experienced at Tarampa. 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 1,274 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 7,195kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 4:00pm 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 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.

4.2.3. Non-Network Solution Summary

Energex 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 Tarampa area to address the identified need.

4.3. Assessment of SAPS options

A Standalone Power System (SAPS) generally constitutes a combination of energy sources and storage, such as renewable energy generation, fossil fuel based generation and battery energy storage system.

For a SAPS to be a viable option to address the identified need, the system would be required to:

- Have the capability to support the peak load;
- Be available continuously with a level reliability that is above the minimum service standard;
- Comply with relevant technical requirements, including fault levels and power quality standards;
- Meet community expectations on noise level and environmental issues.

This option has been assessed as technically not viable, as such a system would require a significant area of land and be located away from residents. Therefore, a SAPS cannot be constructed at the existing substation location.

4.4. Preferred Network Option

Energex’s preferred internal network option is Option A: Replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear.

Upon completion of these works, the asset safety and reliability risks at Tarampa 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 $10.01 million. Annual operating and maintenance costs are anticipated to be same as the existing network as a result of this option. The estimated project delivery timeframe has design commencing in 2024 and construction completed by April 2027.

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, Energex has analysed the classes of market benefits required to be considered by the RIT-D.

5.1. Classes of Market Benefits Considered and Quantified

Value of Customer Reliability, or involuntary load shedding and avoidance of future emergency replacement of assets have been considered and quantified in this analysis. All Market benefits considered have been listed in section 3.2 for completeness.

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. As discussed in Section 3.2 a number of scenarios exist where an in-service failure of an isolator results in a network outage.

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

5.2.2. Changes in Costs to Other Parties

Energex 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 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 Tarampa area.

5.2.5. Changes in Network Losses

Energex 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].

Energex 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

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

[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 Regulatory Investment Test for Distribution requires Energex 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. 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.

6.3. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 1.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)	PV of Benefits ($ real)
A	Replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear	1	$10,085,180	$16,350,000	-$10,085,000	-$89,000	$26,524,000
B	Remove problematic plant items, replace the 33kV and 11kV outdoor switchgear and recover 1 x 5MVA 33/11kV aged transformer, install a mobile kiosk and upgrade 11kV feeders	2	$11,785,180	$14,035,000	-$11,785,000	-$949,000	$26,769,000

Table 1: Base case NPV ranking table

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.

Energex 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

Energex's preferred option is Option A, to replace end of life transformer (TR1) with 1 x 5/8 MVA 33/11kV transformer and replace outdoor 33kV and 11kV switchgear with indoor switchgear at Tarampa Substation.

Upon completion of these works, the asset safety and reliability risks at Tarampa 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 $10.09 million. Annual operating and maintenance costs are anticipated to be same as the existing network as a result of this option. The estimated project delivery timeframe has design commencing in January 2024 and construction completed by April 2027.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

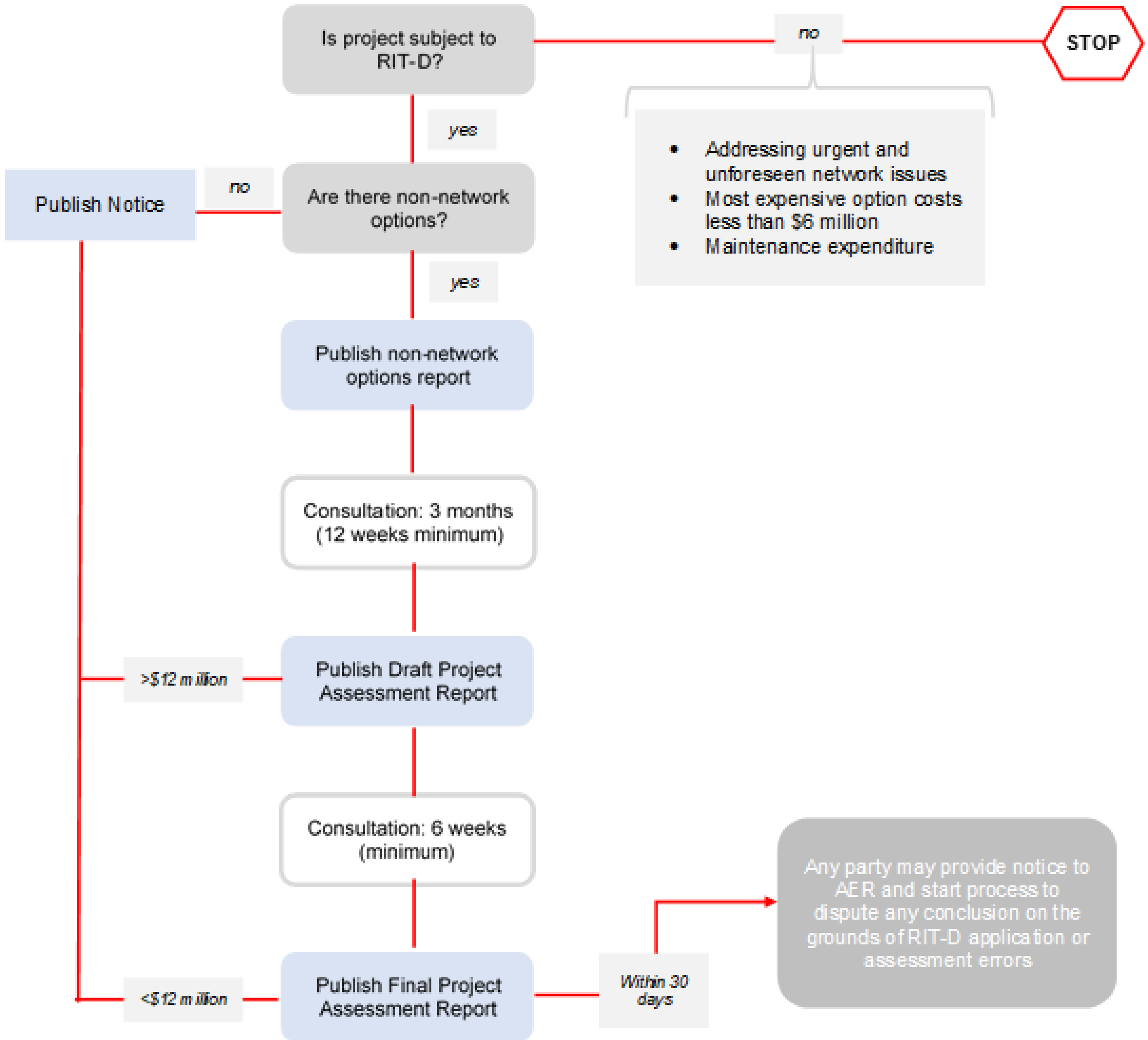
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

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;	4
(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	6
(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.	1.4

APPENDIX A – THE RIT-D PROCESS



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