Final Project Assessment Report

Pittsworth Regional Reinforcement

This document describes the *identified need* for investment at Broxburn substation and the preferred option for addressing the identified need.

Publication Date: 1 October 2020

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

Broxburn 33/11kV substation (BROX) has two 5MVA 33/11kV transformers supplying the township of Pittsworth and surrounding rural areas including some relatively significant chicken farm loads. Peak demand was 10.46MVA in February 2018 which exceeded the substation nameplate capacity and is expected to exceed the emergency cyclic capacity by 2022.

The two transformers at BROX were manufactured in the 1960s (58 years old) and the Condition Based Risk Management (CBRM) methodology calculates the end of life of the transformers at 2025 and 2029 respectively. Neither transformer has bunding or oil containment systems posing an environmental risk for aged transformers in poor condition. Adding to this, the transformers are of an unusually narrow configuration. This is problematic because if a failure occurs, they cannot be replaced with any Ergon Energy standard transformers or contingency spares due to lack of clearance to the bus. There are also a large number of high voltage switches that are nearing end of life, and the transformer protection scheme does not meet the current protection standard[1] of Ergon Energy.

Based on load forecasts, the substation is expected to exceed its emergency cyclic capacity with both transformers in service by 2022. Without addressing these emerging constraints proactively, during peak load times this will result in forced load shedding.

A significant number of primary plant within BROX is at the end of life as determined by the CBRM methodology. If this aged equipment is not replaced before the nominated end of life, there will be an increased likelihood of plant failure. As well as presenting safety risks, the unplanned, sporadic and uncontrolled nature of such failures increases the costs of rectification. The proposed investment under this project addresses these limitations in an economic, efficient and safe manner.

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 Pittsworth supply areas

[1] STNW1002 Standard for Substation Protection

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

Ergon Energy published a Draft Project Assessment report (DPAR) on 7 April 2020 where the technical and financial analysis of the internal options were provided. Written submissions to the DPAR were invited. One submission was received by the closing date of 29 May 2020. The submission proposed to install a battery energy storage system (BESS) that will defer the installation of primary plant to augment capacity. This submission was considered and a technical and comparative net present value (NPV) analysis was completed to gauge the feasibility of this submission against the internal options.

Three potentially feasible options have been investigated in this report:

1. **Option 1 –** 10MVA skid at BROX (internal option)
   This will require the installation of two 10MVA skids at BROX, and a 10MVA skid at Yarranlea South 33/11kV substation (YASO) in stages to align with the demand and replacement date of aged assets.

2. **Option 2** – 2x10MVA skid at BROX (internal option)
   This will require the installation of two 10MVA skids at BROX simultaneously by 2021, and a 10MVA skid at YASO by 2028.

3. **Option 3** – Battery Energy Storage System (external submission provider)
   This proposes the installation of a 10MW BESS for peak lopping by 2021, a 10MVA skid at YASO by 2028, and a 10MVA skid at BROX by 2029.

The external submission (i.e. Option 3) was technically feasible for peak lopping. However, it does not address the aged plant replacement drivers. Option 3 was also found to be the least financially optimal solution.

This is now a Final Project Assessment Report (FPAR), where Ergon Energy presents the technical and financial analysis of the above options and identifies the preferred solution in accordance with the requirements of clause 5.17.4(o). Ergon Energy's preferred solution is Option 1 – 10MVA skid at BROX. This option will achieve the reliable and safe supply of electricity in the Pittsworth area.

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1. Introduction

This FPAR has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(o) of the National Electricity Rules (NER).

This report represents the final stage of the consultation process in relation to the application of the Regulatory Investment Test for Distribution (RIT-D) on potential credible options to address the identified need for BROX. Ergon Energy intends to commence with the preferred network option which is to install a 10MVA skid substation at BROX and subsequently another 10MVA skid at YASO.

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

1.1. Response to the DPAR

Ergon Energy published a DPAR for the identified need (refer to section 3) in the Pittsworth supply area on 7 April 2020. One submission was received by the closing date of 29 May 2020.

1.2. Structure of this report

This report includes information relating to the following matters:

- Provides background information on the network capability limitations of the distribution network supplying the Pittsworth 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 Ergon Energy currently considers may address the identified need, including for each:
    - Its technical definitions;
    - The estimated commissioning date; and
    - The total indicative cost (including capital and operating costs)
- Sets out the technical characteristics that a non-network option would be required to deliver in order to address the identified need.
- Is an invitation to registered participants and interested parties to make submissions on credible options to address the identified need.

1.3. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5(a) of the NER, Registered Participants or Interested Parties may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Accordingly, Registered Participants and Interested Parties who wish to dispute the conclusions outlined in this report based on a manifest error in the calculations or application of the RIT-D must do so within 30 days of the publication date of this report. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred option to install a 10MVA skid substation at BROX and subsequently another 10MVA skid at YASO.

1.4. Contact Details

Inquiries about this RIT-D may be sent to:

E: demandmanagement@ergon.com.au

P: 13 74 66

2. Background

Pittsworth is a township southwest of Toowoomba known for its agricultural and animal industries. Electricity is supplied to 2,877 customers which comprises of 2,258 domestic and 619 industrial, commercial and agricultural loads. These customers are supplied by substations at Broxburn (BROX) and Yarranlea South (YASO). The primary 33kV subtransmission supply comes from Yarranlea T10 (YARA T10) 110/33kV bulk supply point that also supplies the substations Norwin (NORW), Cecil Plains (CEPL), Pampas (PAMP), and Millmerran (MILM). Figure 1 and Figure 2 below provide an overview of the subtransmission network in the region and the location of Broxburn substation.

YARA T10 110/33kV and PAMP 33/11kV show capacity constraints in an N-1 contingency which are addressed in other projects outside the scope of this report. The 33kV subtransmission network is forecast not to be constrained until past 2028.

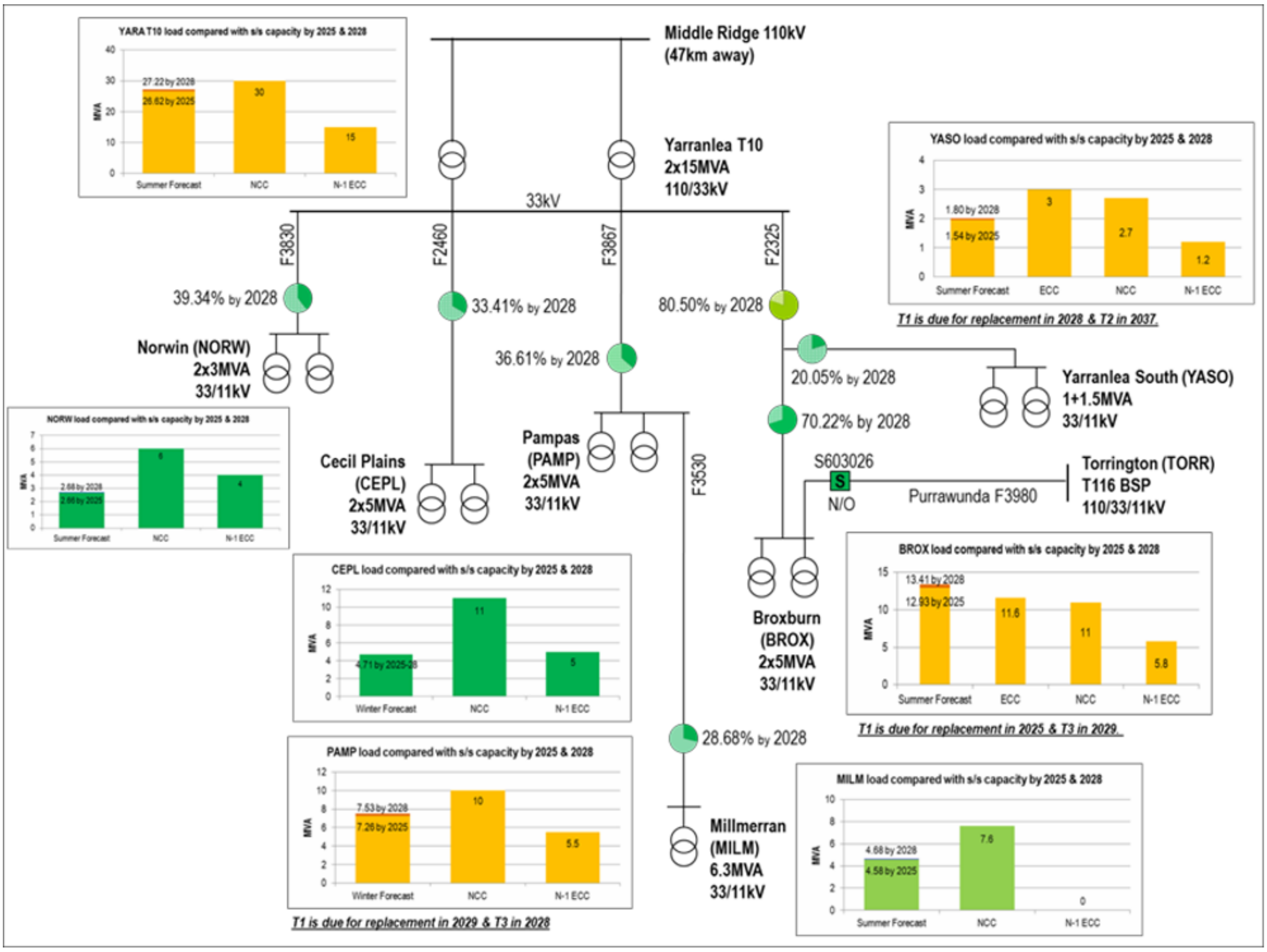


Figure 1: Overview of the 33KV subtransmission network from Yarranlea T10.

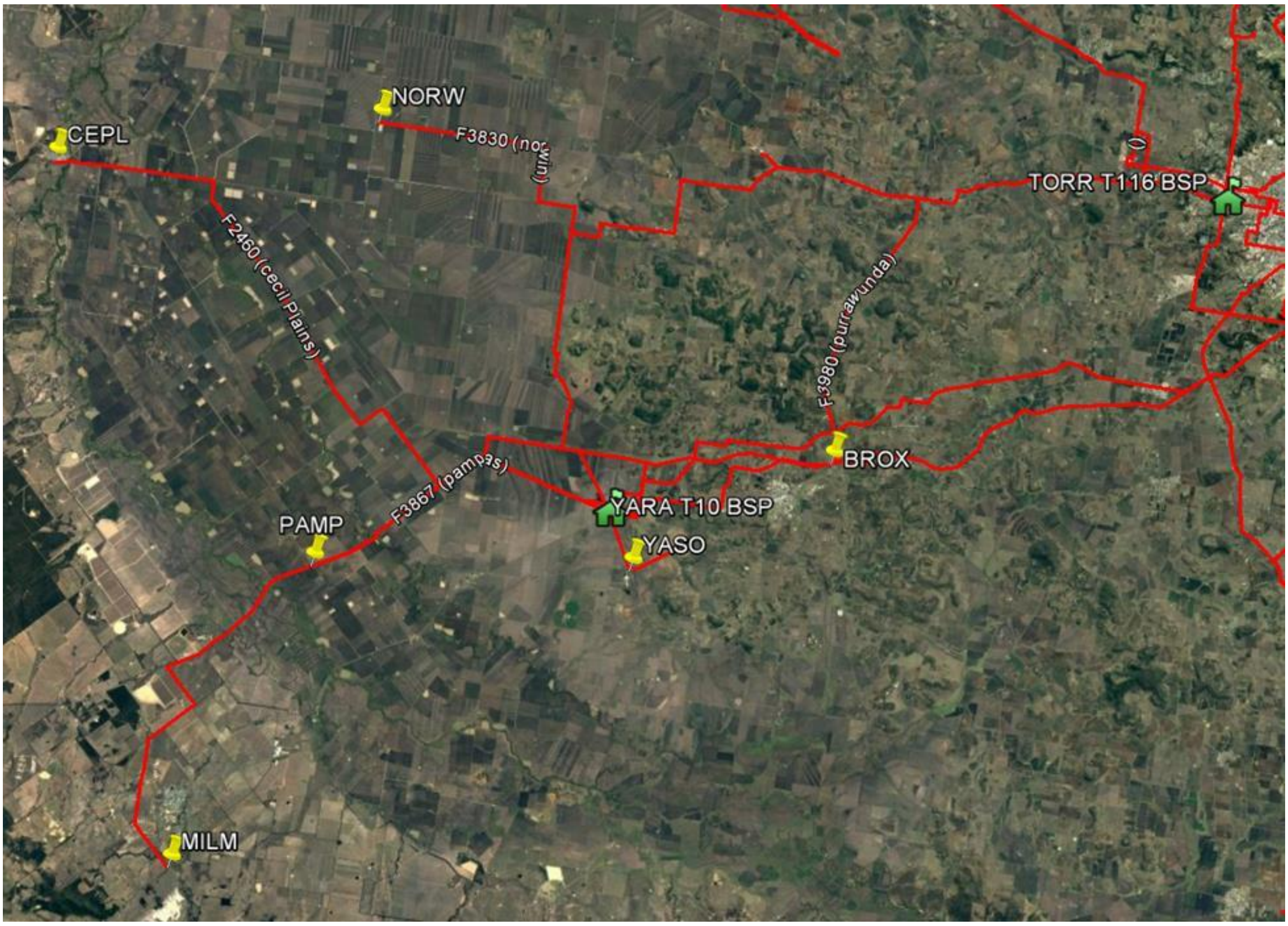


Figure 2: Geographic view of existing network arrangement.

2.1 Existing Substation Capacity

Table 1: BROX transformer ratings.

ZS	Transformer	Nameplate Rating (MVA)	kV	YOM	Cooling	NCC	ECC
BROX	1	5	33/11	1962	ONAN	5.5	5.8
BROX	3	5	33/11	1966	ONAN	5.5	5.8

2.2 BROX Substation Load Profile and Forecast

As shown in Figure 3, BROX load is currently breaching N-1 ECC and is approaching substation NCC and ECC. Peak demand was 10.46MVA in February 2018.

The annual load duration curve for BROX shown in Figure 4 illustrates that currently when either transformer is out of service, substation load exceeds the N-1 ECC rating 7.5% of the time. This is equivalent to 657 hours annually.

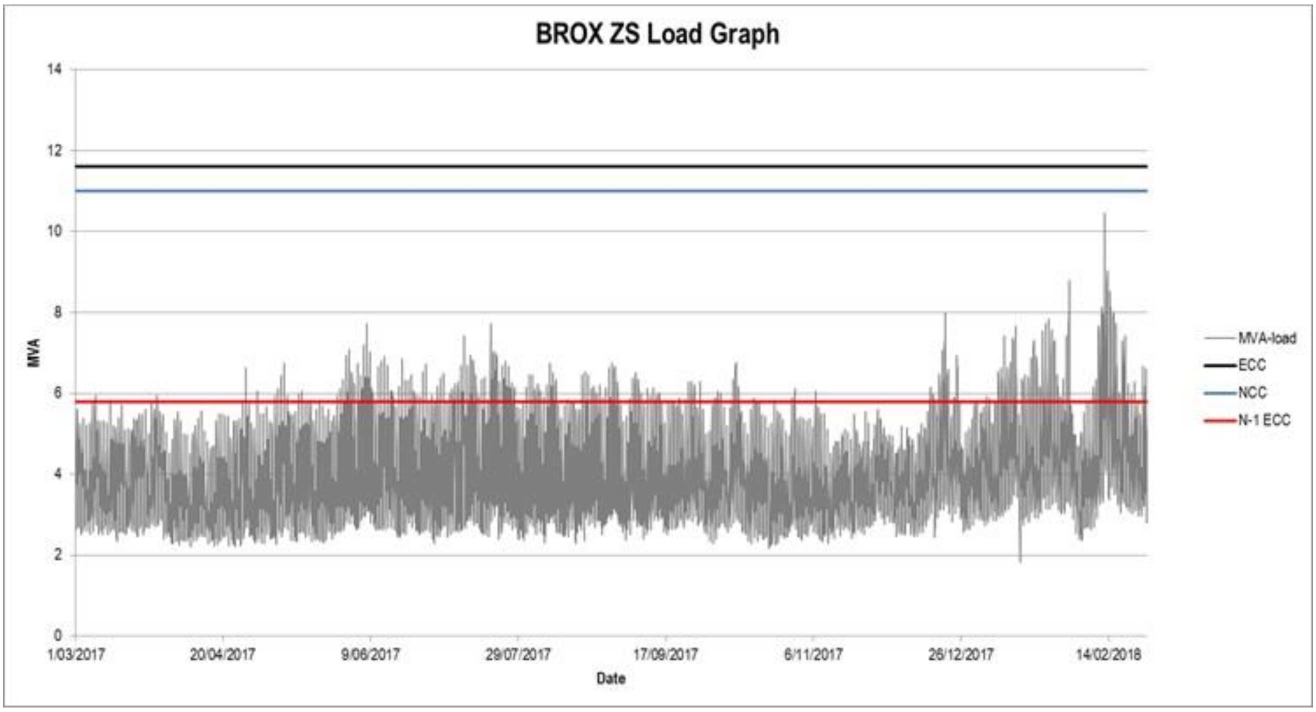


Figure 3: BROX substation historical load.

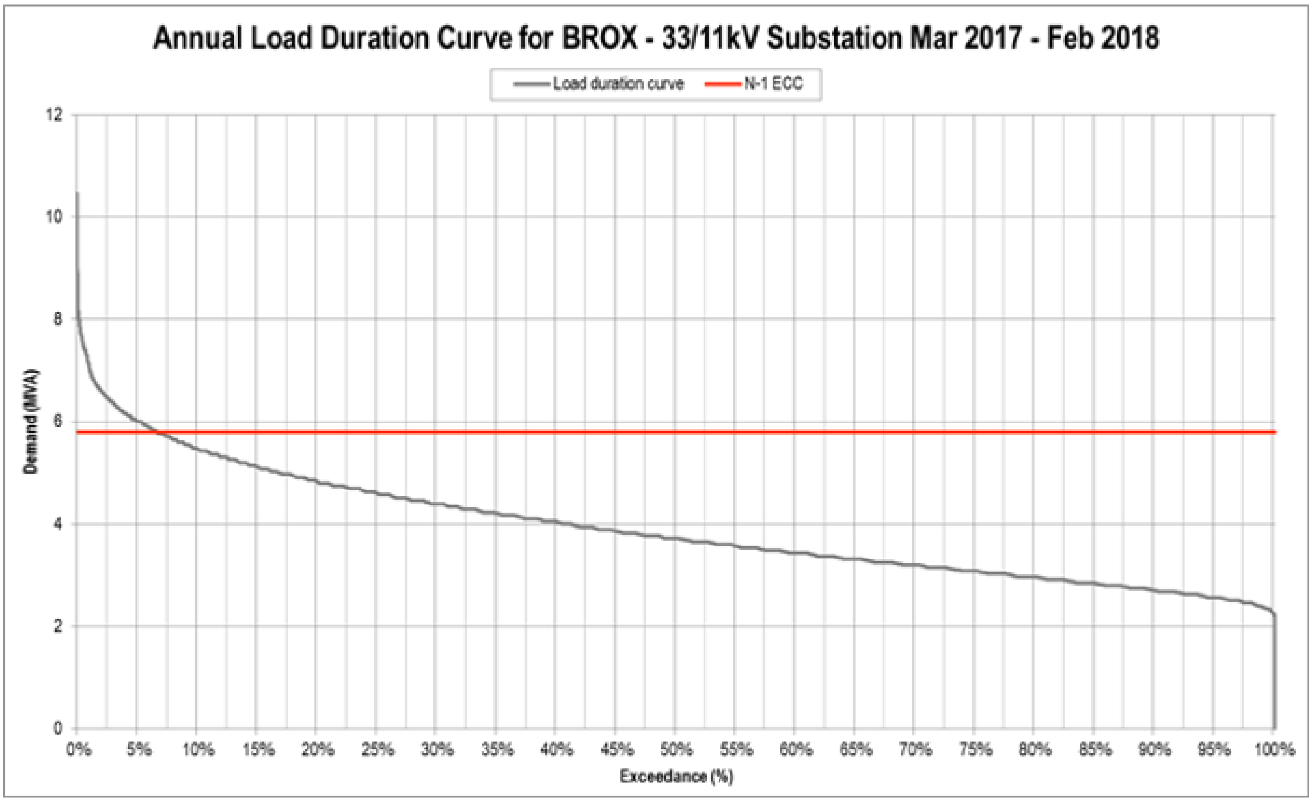


Figure 4: BROX load duration curve.

Figure 5 is the load forecast at BROX and shows an abrupt increase in demand in 2019 and 2022 due to two customer connection applications.

It can be seen that the N-1 ECC rating of the substation is currently being exceeded and that by year 2022, the NCC and ECC (with both transformers in service) ratings will be exceeded as well.

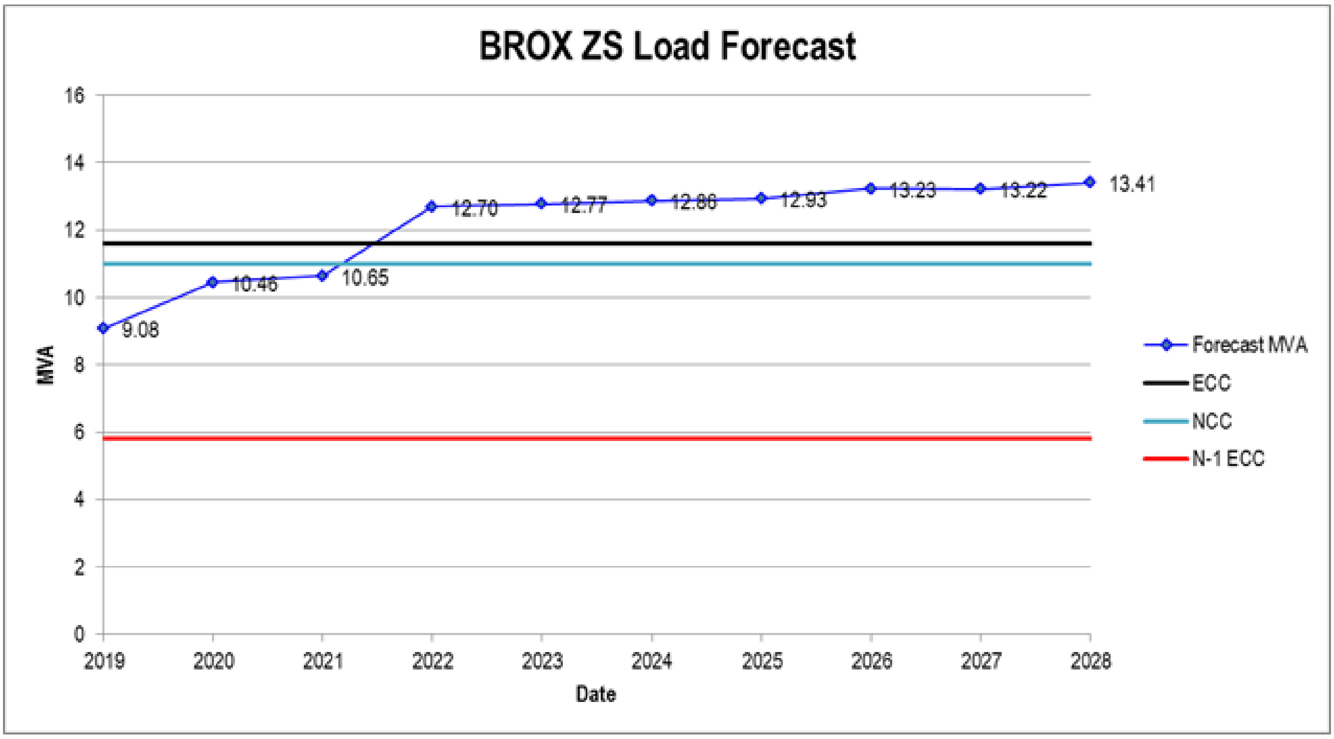


Figure 5: BROX substation forecast.

3. Identified Need

3.1 Description of the Identified Need

The identified need for investment is to remediate the inevitable shortage in capacity at BROX and the near end of life of primary plant in order to maintain the reliable and safe supply of electricity in the Pittsworth area.

- **Future substation capacity**

Based on load forecasts, the substation is expected to exceed its normal cyclic and emergency cyclic capacities with both transformers in service by 2022. Without addressing these emerging constraints proactively, during peak load times this will result in forced load shedding.

- **Aged and poor condition assets**

The two power transformers at BROX substation and several high voltage switches are approaching the end of life as determined by the CBRM methodology. If this aged equipment is not replaced before the nominated end of life, there will be an increased likelihood of plant failure. As well as presenting safety risks, the unplanned, sporadic and uncontrolled nature of such failures increases the costs of rectification.

The power transformers do not have any oil containment systems around them, which presents an environmental risk in the event of an oil leak. The transformer protection scheme also does not conform to the current protection standard (STNW1002 Substation Protection Standard) of Ergon Energy.

3.2 Quantification of the Identified Need

- **Capacity constraint**

Ergon Energy must ensure that there is sufficient capacity to enable customers to connect new loads and to avoid customer load shedding during peak demand. Loads at BROX are forecast to exceed the normal cyclic and emergency cyclic capacities of its transformers in 2022 with both transformers in service. Without addressing these emerging constraints proactively, during peak load times this will result in forced load shedding as well as the inability to connect new customers.

- **Reliability**

The second objective of this investment is to maintain the reliability of customer supply by managing network assets at BROX.

- **Risk management**

The final objective of the investment in this part of the network is to mitigate all risks identified to As Low as Reasonably Practicable (ALARP). Refer to Appendix A – Risk Assessment at Broxburn substation.

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.

- **Load Profile**

Characteristic peak day load profiles shown in Section 2 are unlikely to change significantly from year to year, i.e. the shape of the load profile will remain virtually the same with increasing maximum demand.

- **Forecast Maximum Demand**

It has been assumed that peak demand at BROX substation will grow as per the base case load forecast.

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)
- forecast growth rates for organic growth

- **System Capability – Transformer capacity**

Transformer ratings are normally specified by a continuous rating, supplied by the manufacturer on the nameplate. This corresponds to the load that will cause the oil and winding temperature rise to meet the specified limit, assuming a constant temperature and a constant rated load.

Cyclic ratings in excess of nameplate ratings are possible because the typical load cycle is not continuous, nor is the daily temperature cycle. Each transformer also has a typical thermal time constant of a few hours. All these factors are combined to enable cyclic loading of a transformer in excess of the nameplate rating before the temperature limits are reached.

Each transformer has two cyclic ratings for both summer and winter, based on the load profile and the ambient temperature for that transformer location. The two cyclic ratings are normal cyclic capacity (NCC) rating and emergency cyclic capacity (ECC) rating.

- **System Capability – Transfer Capacity**

In times of contingency, for example when one transformer is faulty, load may be transferred to another substation via the distribution network. The distribution network transfer capability is largely determined by the capacity of the powerlines to carry the transferred load as well as their ability to maintain system voltages.

4. Non-Network Alternatives

Ergon Energy's Demand and Energy Management (DEM) team has conducted an internal assessment of the potential for non-network alternatives. Their assessment is available at Appendix B - Internal Assessment for Non-network Alternatives.

4.1 Feasible vs Non-Feasible Options

4.1.1 Potentially Feasible Options

The identified need presented in this RIT-D report is driven by the limitation in transformer capacity and the near end of life of plant which are necessary for the reliable supply of electricity. As such, solutions that cost-effectively address the capacity and end-of-life plant at BROX through augmentation and/or replacement within the required parameters are likely to represent reasonable options. Any option must also address the objectives to mitigate environmental and safety risks to ALARP.

A non-exhaustive list of potentially feasible options includes:

- Additional transformer capacity to supply the forecast demand for the next 40-50 years.
- Replacement of plant nearing end-of-life.
- Providing demand management or generation strategies that postpone the required augmentation/replacement expenditure.

4.1.2 Options that are unlikely to be feasible

Without attempting to limit a potential proponent's ability to innovate when considering opportunities, some technologies/approaches are unlikely to represent a technically or economically feasible solution.

Unproven, experimental or undemonstrated technologies are unlikely to be feasible if the:

- Option does not meet all the objectives stated in Section 3.
- Option requires completion beyond 2022.
- Options that do not meet or are unable to demonstrate they can meet the Service Standards of Ergon Energy.

4.1.3 Timing of feasible options

The consequence of not addressing aging plant and equipment and not meeting Safety Net is significant. As a result, it is expected that for an option to be considered feasible it is required to be completed, commissioned, accepted by Ergon Energy, and fully operational by 2022.

5. Technical requirements of the solution

A suitable solution to meet Ergon Energy's operational requirements should address the limitations in substation capacity, aging plant and equipment and identified network and safety risks at BROX. Ergon Energy is willing to consider other possible solutions which may be identified as part of the RIT-D process. The alternate non-network solutions must comply with several Ergon Energy standards which include, but are not limited to, Safety Net security standards, quality of supply, design and safety standards.

The following are general parameters to which a non-network option must comply with. It is expected that any proposed solution is in accordance with good electricity industry practices, such that a high reliability and availability solution is delivered.

5.1 Substation Capacity

The following pertains to substation capacity for any non-network solution:

1. Transformer capacity (or capacity) will be available to accommodate demand, large customer applications, and load forecast.
2. Capacity will be available in the event of transformer failure.
3. Capacity will be adequate when transferring load to another substation and/or source during contingency.

5.2 Aging Plant and Equipment

The existing plant at Broxburn is mostly 1960s era. A non-network option must address the risk to the network and plant and personnel from operating such plant which is at the end of its lifecycle (year of manufacture, use, end of life).

5.3 Compliance with Regulations and Service Standards

5.3.1 Minimum Service Standards

Under its Distribution Authority (DA) Ergon Energy is responsible for electricity supply to the Pittsworth area. The DA requires that Ergon Energy must:

- Comply with the Guaranteed Service Levels regime notified by the Queensland Regulator which includes reliability of supply to customers;
- Plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services;
- Use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (System Average Interruption Duration Index and System Average Interruption Frequency Index limits) applicable to its feeder types; and
- Ensure, to the extent reasonably practicable, that it achieves its Safety Net targets (refer to Table 2).

5.3.2 Safety Net

The non-network option must satisfy the Safety Net security standard and meet the restoration times for loads not supplied during contingencies outlined in Table 2 below.

Table 2: Safety Net restoration times. BROX is classified rural area.

Safety Net – Load not supplied and maximum restoration time following a credible contingency	
Regional Centre	**Rural Area**
Less than 20MVA (8000 customers) after 1 hour; Less than 15MVA (6000 customers) after 6 hours; Less than 5MVA (2000 customers) after 12 hours; and Fully restored within 24 hours.	Less than 20MVA (8000 customers) after 1 hour; Less than 15MVA (6000 customers) after 8 hours; Less than 5MVA (2000 customers) after 18 hours; and Fully restored within 48 hours

5.4 Land and proximity to Substation

Ergon Energy owns some additional land at BROX (refer to Figure 6). Ergon Energy is open to discussions around the use of these lands as part of the non-network solution.

Figure 6: BROX substation land and site dimensions

6. Internal Option Identified

Ergon Energy's preferred internal option is to install a skid transformer at BROX which will address capacity and aged plant limitations, satisfy all service standards and presents the best financial return on investment. The estimated project delivery timeframe has the target year for completion in 2022 prior to the forecast limitations at BROX. Operating expenses for new infrastructure are typically 1% - 2% of the capital cost.

Table 3 provides the approximate anticipated capital cost for the proposed solution. It is noted at the time of writing the RIT-D more detailed cost estimates are being performed which may cause some change to the below figures.

Table 3: Ergon Energy's internal cost for the preferred option.

Internal option	10MVA skid at Broxburn Substation
ACP	$6,865,316

6.1 Scope of the Preferred Internal Option

The following works are proposed to be carried out as part of the preferred network solution at BROX, Figure 7:

- Extend the substation earth grid to accommodate the installation of a skid-mounted substation.
- Install a standard 10MVA 33/11kV skid with 1 x 10MVA 33/11kV transformer (Dyn11), 1 x 33kV recloser, 3 x 11kV reclosers and 1 x 63kVA 11/0.415kV station service transformer.
- String two spans of Cherry 14.3mm ACSR to relocate the 33kV line between YARA T10 and TORR T116 from inside to outside the substation.
- Include provision for statistical and revenue metering.
- Extend / rebuild substation security fence to include the new skid.
- 11kV distribution works to pick up Springside, Pittsworth and Copps Hill 11kV feeders from the 10MVA skid-mounted transformer.
- Install communications cabling between skid and the existing control room.

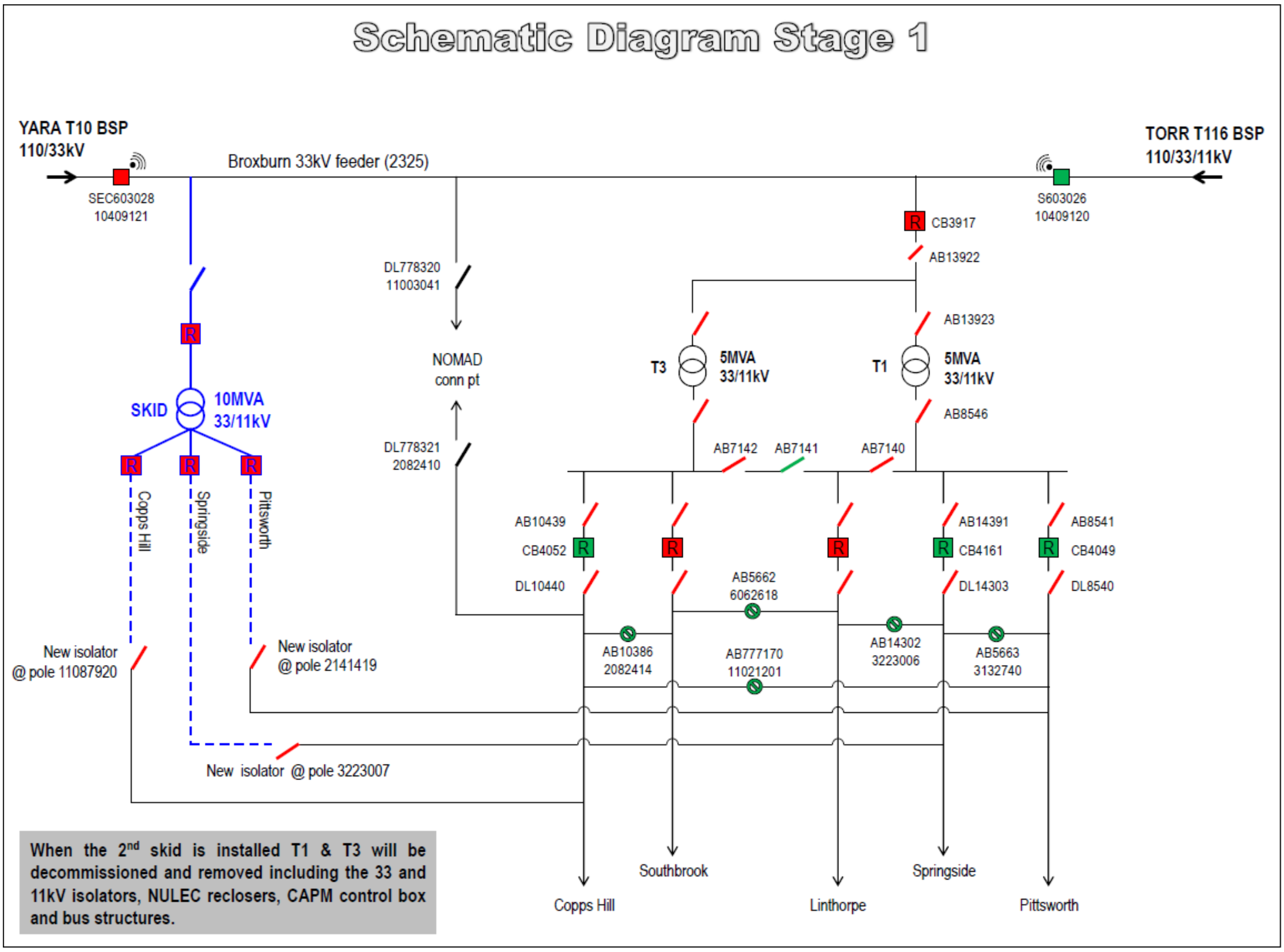


Figure 7: BROX single line diagram with proposed skid substation.

6.2 Options Considered

Ergon Energy investigated a number of network options to address the identified need at BROX. The options were narrowed down to three, i.e. two internal options and one non-network option. Details of the credible options are presented in the following sections.

6.2.1 Option 1 – 10MVA skid at BROX (internal option)

This will require the installation of two 10MVA skids at BROX, and a 10MVA skid at Yarranlea South 33/11kV substation (YASO) in stages to align with the demand and replacement date of aged assets, i.e. Stage 1 - 10MVA skid at BROX by 2021, Stage 2 – 10MVA skid at YASO by 2028 and Stage 3 – 10MVA skid at BROX by 2029. **This option is preferred because it is the most economically optimal (refer section 9), technically feasible along with meeting safety net compliance requirements.**

6.2.2 Option 2 – 2x10MVA skid at BROX (internal option)

This will require the installation of two 10MVA skids at BROX simultaneously by 2021, and then a third 10MVA skid at YASO by 2028. Since this option requires a greater upfront capital expense, it is less economically optimal as compared to Option 1.

7. External Submissions Received

In response to the DPAR published by Ergon Energy, one external submission was received. This submission proposes the installation of a 10MW Battery Energy Storage System (BESS) for peak lopping by 2021, a 10MVA skid at YASO by 2028, and a 10MVA skid at BROX by 2029.

This option is not safety net compliant as demonstrated in Figure 8 for the failure of the most critical substation asset, which in this case is the failure of T1. The expected performance of the BESS installed at BROX on peak load days is demonstrated in Figure 9.

Figure 10 provides the expected BESS state of charge in relation to the peak demand and the normal cyclic capacity of the remaining transformer T3.

It may be noted here that T3 is also an aged asset identified to be replaced in 2028/9, which will require additional investment to manage demand.

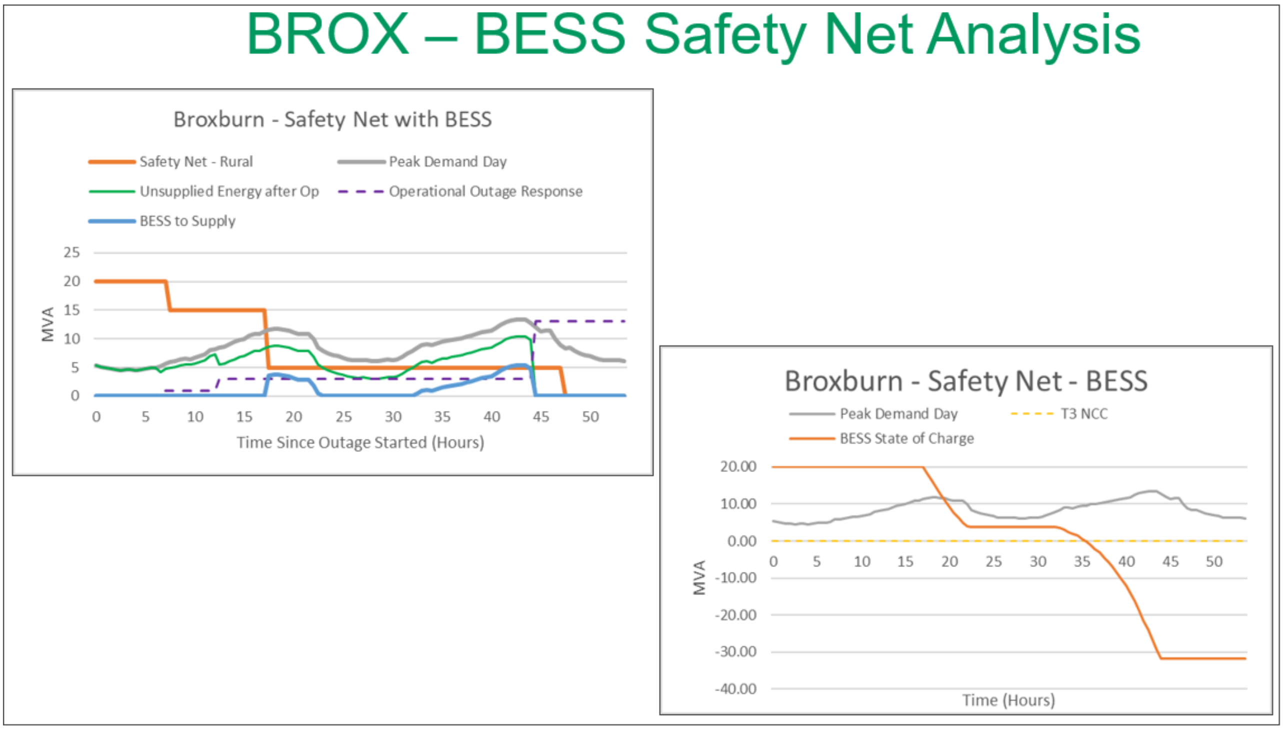


Figure 8: Safety Net security standard vs BESS to supply the unsupplied load.

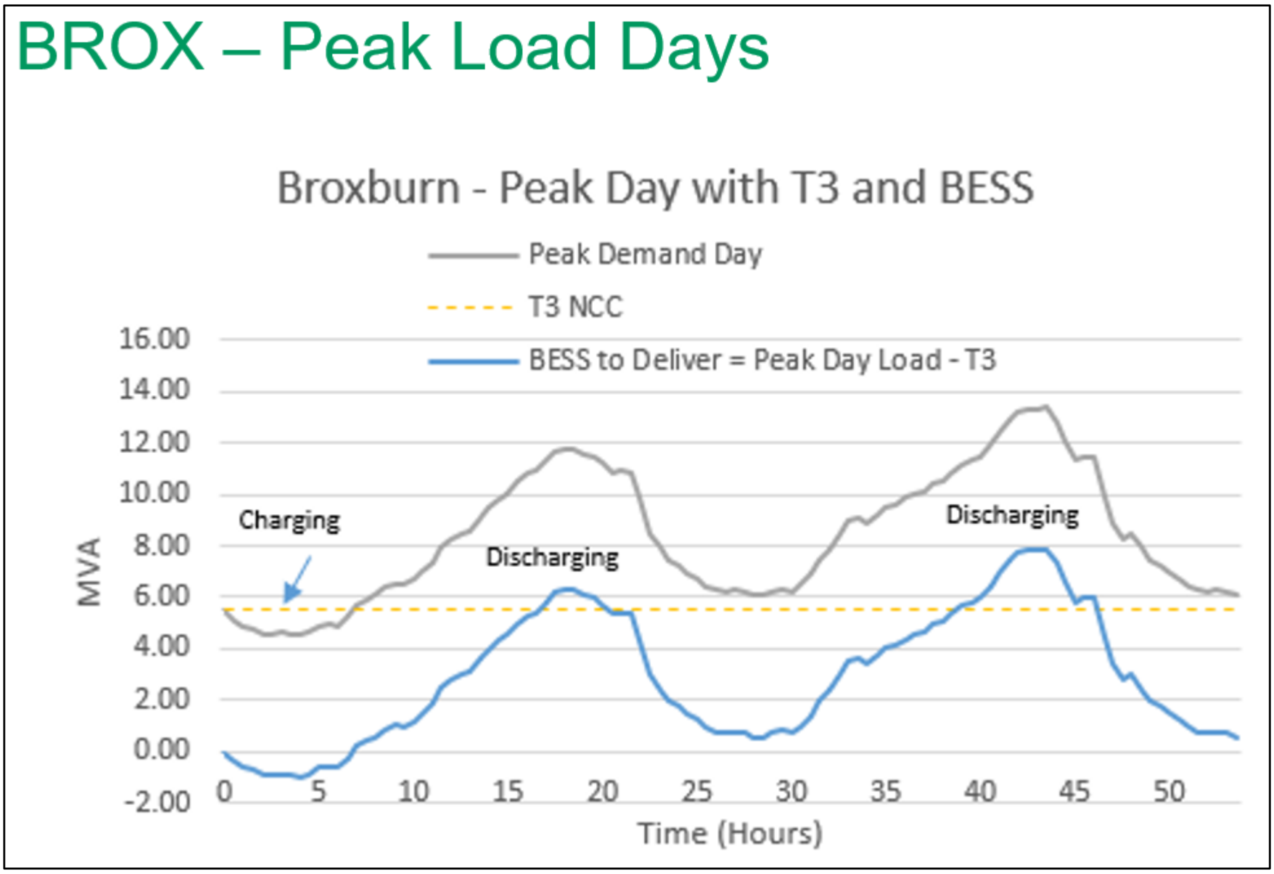


Figure 9: Performance of the BESS on peak load days.

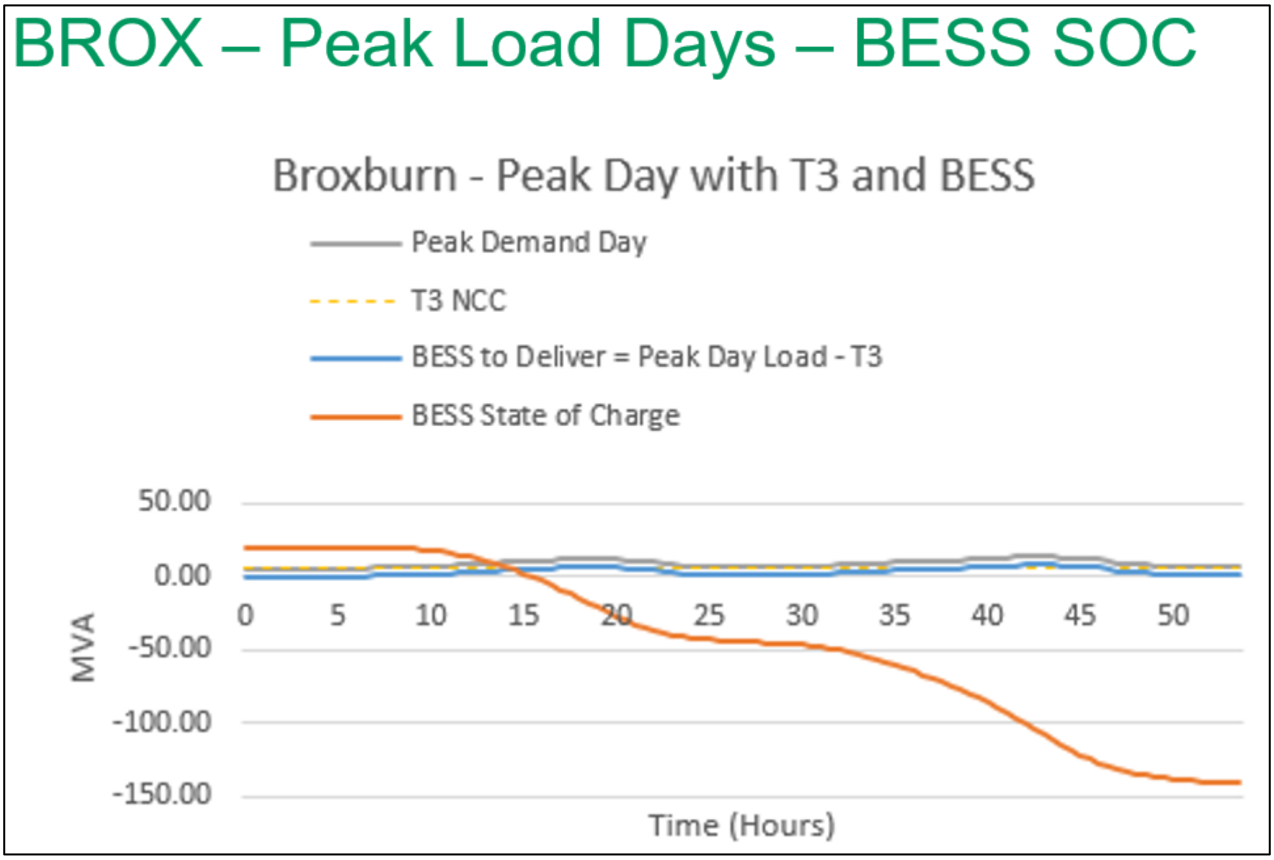


Figure 10: BESS state of charge vs peak demand and NCC capacity of T3.

8. Market Benefits

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). Consistent with NER clause 5.17.1(c)(4), Ergon Energy has considered the following classes of market benefits:

- Changes in voluntary load curtailment;
- Changes in involuntary load shedding and customer interruptions caused by network outages using a reasonable forecast of the value of electricity to customers;
- Changes in costs for parties other than the RIT-D proponent due to differences in the timing of new plant, capital costs, and operating and maintenance costs;
- Differences in the timing of expenditure;
- Changes in load transfer capacity and the capacity of embedded generators to take up load;
- Any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the NEM; and,
- Changes in electrical energy losses.

8.1 Changes in Voluntary Load Curtailment

None of the options considered in this RIT-D include any voluntary load curtailment. There are currently no customers on such arrangements in the Pittsworth area. Any market benefits associated with changes in voluntary load curtailment have not been considered.

8.2 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. A reduction in involuntary load shedding is expected from all the credible options presented in this report. The fact is that the aged substation assets present an area wide level of risk to the supply network. The benefits from changes in involuntary load shedding have not been quantified and considered in this report because it isn't significant to impact the options that are feasible, meets the Safety Net security of supply criteria, and address the aged substation assets.

8.3 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.

8.4 Differences in Timing of Expenditure

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

8.5 Changes in Load Transfer Capacity

None of the options included in this RIT-D assessment are expected to affect the load transfer capacity in the Pittsworth area.

8.6 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.

8.7 Option Value

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

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 the future.

9. Economic Analysis

A net present value (NPV) was completed to determine which option is most optimal. The NPV is for investment planning to analyse the financial gain of each option. Table 4 shows the result of the NPV across the three options. A positive net present value indicates it is a 'gain' and negative is a 'loss'. In this instance, the least negative NPV is the most optimal.

Table 4: NPV results of the three options, $M.

BASE CASH FLOWS NPV ANALYSIS			
PROJECT:	1266675 CBRM SW BROX STAGE1 10MVA SKID		
Results displayed in $000s			
WEIGHTED AVERAGE RESULT ACROSS ALL SCENARIOS			
AVERAGE Option	Option Name	Rank	Net NPV
1	10MVA skid at BROX	1	-13,269
2	2 x 10MVA skid at BROX	2	-13,299
3	Battery Energy Storage System	3	-33,345

Note: The capital cost submitted for Option 3 has been withheld on request due to confidentiality reasons. Instead the NPV in terms of its financial performance over a 60-year investment period has been presented in this report.

Option 1 is the only identified option which will meet both the technical requirements identified in Section 5 and economically optimal.

10. Conclusion

This document is being published as the FPAR under NER clause 5.17.4(o), following the publication of the Non-Network Options Report on 1 Jul 2019 and the DPAR on 7 Apr 2020. This Final Project Assessment Report represents the final stage of the RIT-D process to address the identified need at Broxburn.

Ergon Energy intends to take steps to progress the recommended solution to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements as necessary.

10.1 Preferred Option

Ergon Energy's preferred solution is Option 1 which is to install two 10MVA skids at BROX, and a 10MVA skid at YASO in stages to align with the demand and replacement date of aged plant. The details of this solution are set out in Section 6.1 of this report. The estimated total capital cost of Stage 1 of the preferred network option is $6.865M. The estimated project delivery timeframe is 2021.

10.2 Satisfaction of the 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.

11. Compliance Statement

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

Requirement	Report Section
(1) a description of the identified need for investment;	3.1
(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 NNOR;	4
(4) a description of each credible option assessed	6,7
(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	NA
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	9
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	NA
(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	8
(9) the results of an NPV analysis of each credible option and accompanying explanatory statements regarding the results	9
(10) the identification of the proposed preferred option	6
(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	5, 6
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	1.4

12. Appendix A – Risk Assessment at Broxburn substation

Risk Category	Equipment	Risk Scenario	Inherent / Untreated Risks			Target (Residual)	
			C	L	Risk Score	L	Risk Score
Customer	Other	Substation ECC breach at BROX results in > 1min changeover outage > 3 times in one week during high load times to allow Nomad load support connection.	3	5	15 (Moderate)	1	3 (Very Low) ALARP
Customer	Transformer	Fault or Non-Spurious Trip on 33/11kV Transformer at BROX results in interruption >24 hours.	4	4	16 (Moderate)	1	3 (Very Low) ALARP
Environment	Transformer	Catastrophic failure of a 33/11kV transformer at BROX results in an oil spill > 1000 litres that extends beyond the property boundary (transformers not bunded).	4	3	12 (Moderate)	1	4 (Very Low) ALARP
Safety	Isolator / Insulator	Catastrophic failure of 33kV isolator at BROX results in serious injuries to multiple field workers or members of public.	4	2	8 (Low)	1	4 (Very Low) ALARP
Safety	Transformer	Catastrophic failure of 33/11kV transformer at BROX results in serious injuries to multiple field workers or members of public. Likelihood based on condition, loading and history	4	4	16 (Moderate)	1	4 (Very Low) ALARP

13. Appendix B – Internal Assessment for Non-network Alternatives

Non Network Alternatives (NNA)

BROXBURN SUBSTATION (BROX) 33/11kV

CI has assessed the potential demand management options required to defer the identified BROX network option and determine if there is a viable non network option to replace or reduce the need for the proposed Network option. CI has reviewed the customer base and considered a number of demand management technologies based on the primary project driver of augmentation to meet a growth forecast to exceed the emergency cyclic capacity by 2022. It is unclear that demand management could assist in any way with addressing the secondary project driver of aged asset replacement. The DM goal would be to extend the life of the transformers by de-loading them at peak times.

There are 2131 residential customers and 581 business customers connected to BROX (refer Figure 1.) 36 business customers are classified as Large, 8 of these sites have significant (> 200 kVA) maximum demand.

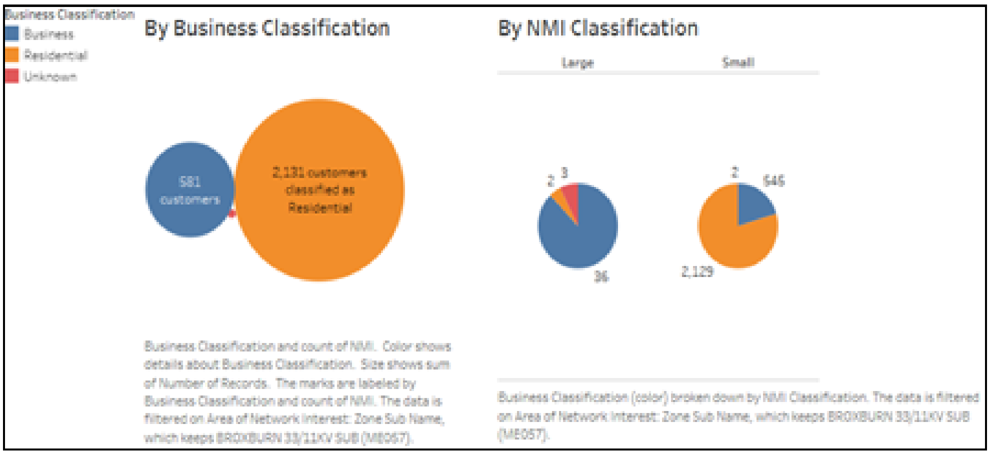


Figure 1

Residential

Residential customers appear to drive the daily peak of demand which occurs between 4.00pm-7.30 pm, (Figure 2) the summer period producing the highest yearly demand. BROX has 1599 customers on tariff T31 and T33 hot water load control (LC); the estimated demand reduction value of which is 959 kVA+. Broxburn substation LC signals are controlled from Yarranlea BSP 110/33 kV substation. The Tariff 33 and 31 Hot water LC channels are dynamic (i.e. respond to exceedance settings not on a timetable) currently LC is scheduled to activate when the BSP exceeds 23.5 MVA; this strategy does not directly address peaks experienced at BROX. Tariff 33 Air-conditioning channels are under manual control of the control room and used as required.

+.Hot water diversified demand saving estimated at 0.6kVA per system

Internal Assessment Report
Non-network Alternatives
Pittsworth Regional Reinforcement WR 1266875

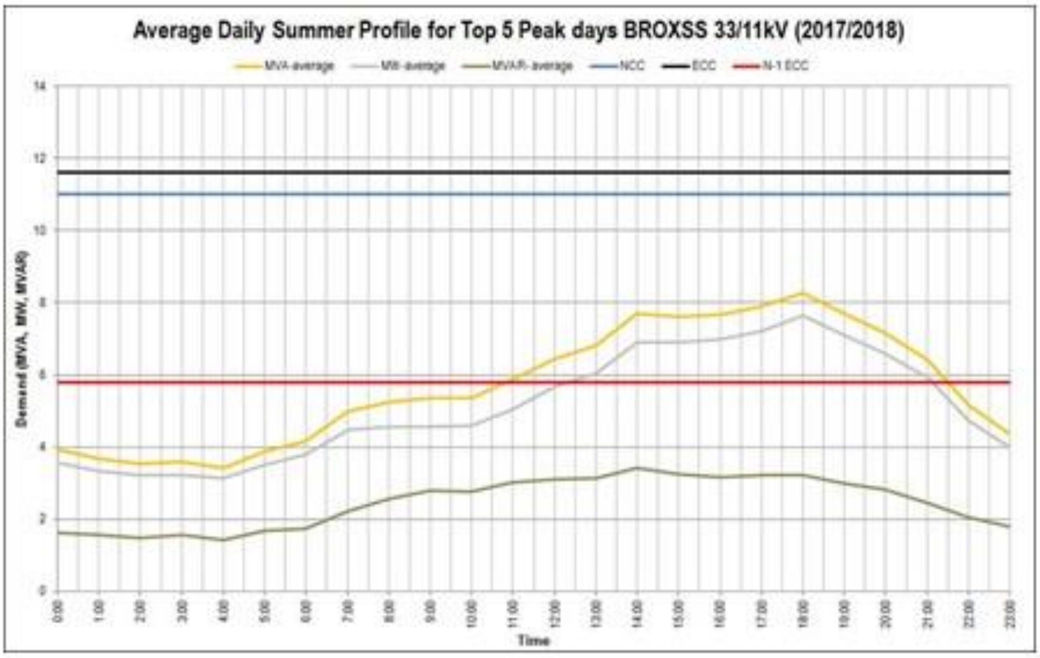


Figure 2

Business

Figure 3

Further analysis of the business customers (seen in Figure 3) shows that 4 of the 8 highest consumption sites have maximum demands of 860 kVA, 674 kVA, 285 kVA, and 65 kVA respectively for a total demand of 1.88MVA. Other notable demands are 355 kVA, 260kVA and 320 kVA. New connection with a demand of 1.5MVA is forecast in 2019 and 2MVA in 2021.

Solar

665 business and residential customers have solar PV systems with a connected kW capacity of 2198 kW's. Pittsworth, Linthorpe, Southbrook and Springside Feeders are registered as at risk of experiencing reverse power flows*.

* Using the total installed capacity of Micro EG Units (with 20% diversity) and Estimated Light Load (20% of Daily Maximum Demand) a rough estimate can be made as to whether generation will exceed the consumption on a feeder.

2

Demand management – BROX

The customer base has a significant industrial and commercial presence interspersed with small business and residential customers. There is opportunity for demand savings in all these customer market segments. The most cost effective demand reduction measure for the residential market in a short timeframe could be increased utilisation of the existing LC measure (which is currently around 959 kVA) on customers by Ergon to de-load BROX.

The large amount of customer solar PV (2198 kW) adds potential for a BESS offering in future.

Commercial incentives for lighting and power factor could be offered for demand reductions but would take a longer term to be realised.

Demand response – BROX

Demand response through customer embedded generation, call off load and load curtailment contracts has been assessed as technically viable as there is significant business customer opportunity with the top existing 7 customer sites. They have significant diesel generation assets and have previously indicated their interest in entering into commercial arrangements for this generation. If the new connection of 1.5MVA is included to the current total demand, the demand reduction would be 3.3MVA.

Other DR opportunities may exist with sites with > 200 kVA maximum demand sites at the Hospital etc.

Summary - BROX

- 665 customers have 2198 kW's PV on the Network
- 4 feeders registered as at risk of experiencing reverse power flows*.
- 959 kVA (est.) of potential T31 and T33 hot water load control.
- Peak demand occurs in summer 4 pm to 7.30 pm driven by residential market
- Significant Industrial and commercial business customers with > 200kVA and existing diesel generation available
- The new connection is willing to enter into NSA for diesel generation

Conclusion

Based on the demand management options considered above, it is deemed that sufficient demand management measures could be feasibly implemented to contribute to technically and economically deferring the network investment required at BROX. Particularly as the primary investment drivers are augmentation triggered by growth with aged asset replacement, reliability, environmental risk, safety and standards compliance listed as secondary drivers.

CI believes there could be financial benefits from seeking expressions of interest from the market for a Non Network Alternative to proposed Network investment suggested in the Planning Report.

14. Appendix C – Ergon Energy's Minimum Service Standards and Safety Net Targets

The legislated System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) limits from Ergon Energy's Distribution Authority are detailed in Table 5**Error! Reference source not found.**.

Table 5: SAIDI (minutes per customer) and SAIFI (interruptions per customer) limits.

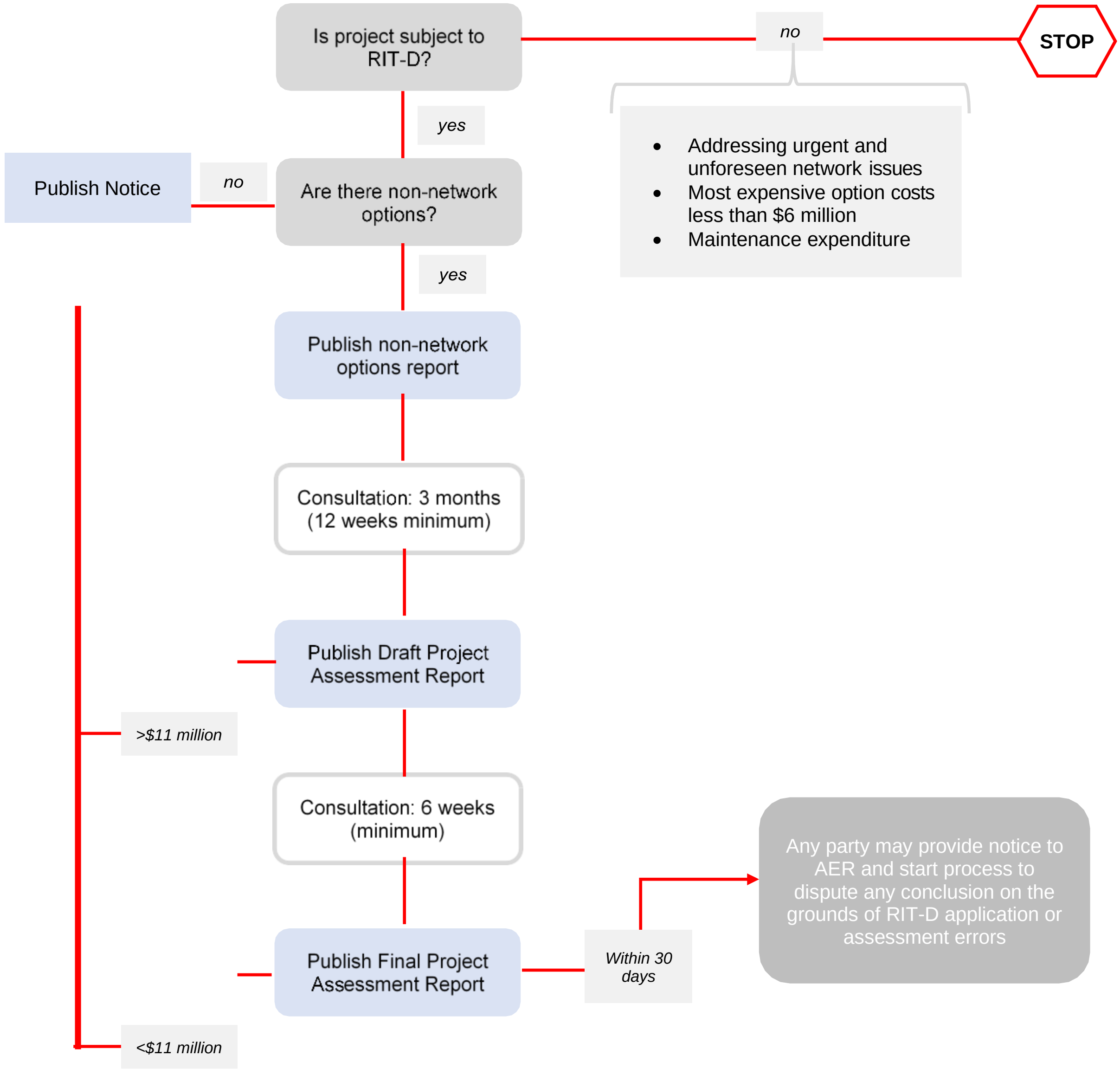
Feeder Category	SAIDI MSS Limit	SAIFI MSS Limit
Urban	149	1.98
Short Rural	424	3.95
Long Rural	964	7.40

The legislated Safety Net Targets from Ergon Energy's Distribution Authority are provided in Table 6. Broxburn is classified a 'Rural Area'.

Table 6: Ergon Energy Safety Net Targets

Area	Targets (for restoration of supply following an N-1 Event)
Regional Centre	Following an N-1 event, load not supplied must be: ○ Less than 20 MVA after 1 hour; ○ Less than 15 MVA after 6 hours; ○ Less than 5 MVA after 12 hours; and ○ Fully restored within 24 hours.
Rural Areas	Following an N-1 event, load not supplied must be: ○ Less than 20 MVA after 1 hour; ○ Less than 15 MVA after 8 hours; ○ Less than 5 MVA after 18 hours; and ○ Fully restored within 48 hours.
Note: All modelling and analysis will be benchmarked against 50 POE loads and based on credible contingencies. 'Regional Centre' relates to larger centres with predominantly urban feeders. 'Rural Areas' relates to areas that are not Regional Centres.	

15. Appendix D – The RIT-D Process



16. Appendix E – Glossary of Terms

Abbreviation	Description
ACP	Approved Cost Plan
ACSR	Aluminium conductor steel reinforced
BROX	Broxburn substation 33/11kV
CBRM	Condition Based Risk Management
CEPL	Cecil Plains substation 33/11kV
CI	Customer Interactions team (currently DEM)
DEM	Demand and Energy Management
ECC	Emergency cyclic capacity
MILM	Millmerran substation 33/11kV
N-1 ECC	Capacity available when the largest transformer fails
NCC	Normal cyclic capacity
NORW	Norwin substation 33/11kV
ONAN	Oil Natural Air Natural
PAMP	Pampas substation 33/11kV
RIT-D	Regulatory Investment Test for Distribution
SLD	Single line diagram
YASO	Yarranlea South substation 33/11kV
YARA T10	Yarranlea (T10) 110/33kV bulk supply point
YOM	Year of manufacture
ZS	Zone Substation (or simply substation)