Service constraints at Traralgon (TGN) Zone Substation

RIT-D Stage 1: Non-network options report

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1 Executive Summary

AusNet Services is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 745,000 customers. Our electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

As expected by our customers and required by the various regulatory instruments that that we operate under, AusNet Services aims to maintain service levels at the lowest possible cost to our customers. To achieve this, we develop forward looking plans that aim to maximise the present value of economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Our planning approach includes the application of a probabilistic planning methodology, under which conditions often exist where some of the load cannot be supplied under rare but possible conditions, such as during extreme demand conditions or with a network element out of service. Where relevant, we also prepare, publish, and consult on a regulatory investment test for distribution (RIT-D), which further helps ensure all credible options are identified and considered, and the best option is selected.

This non-network options report is stage one of the RIT-D consultation process to address the existing and emerging service level constraints in the Traralgon (TGN) Zone Substation supply area. The report has been prepared by AusNet Services in accordance with the requirements of clause 5.17 of the National Electricity Rules (NER).

1.1 Identified need

TGN commenced operation as a 66/22kV transformation station in 1969. Two 10/13.5 MVA transformers were manufactured in 1949 and 1979, and one 20/33 MVA transformer was manufactured in 2012.

The 22kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22kV busses with four feeder CBs installed in 1969. The 66kV switchyard has had some modifications since the site was established, and now consists of two 66kV lines to MWTS and one line to Maffra Zone Substation.

Two of the 66kV circuit breakers were installed in 1977, while the other two were installed in 2013 when the new 20/33 MVA transformer was installed. The station 66kV bus is partially switched with the two 10/13.5MVA transformers connected in a single switching zone group.

The physical and electrical condition of some assets has deteriorated and they now present an increased failure risk. The key service constraints at TGN are:

- Security of supply risk presented by the switching of the No.2 and No.3 transformers in a single group, and lack of 66kV ring bus;
- Security of supply risks presented by increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
- Plant collateral damage risks presented by a possible explosive failure of a number of the assets;
- Environmental risks associated with insulating oil spill or fire;
- Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets;
- Health and safety risks presented by exposed live terminals at the rear of the secondary panels in the control room; and

- Health and safety risks presented by asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

1.2 Credible options

The potentially credible options that AusNet Services believes may be capable of meeting the identified need include:

1. Do Nothing (counterfactual)
2. Retire one transformer
3. Retire one transformer and reduce residual risk through network support
4. Network support to defer retirement and replacement
5. Replace 22kV switchgear with new switchboard
6. Replace two 66kV circuit breakers and 22kV switchgear
7. Integrated replacement

1.3 Submissions

AusNet Services invites written submissions on the matters set out in this non-network options report from Registered Participants, AEMO, interested parties, non-network providers and those registered on our demand side engagement register.

All submissions and enquiries should be directed to:

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Submissions are due on or before 20 August 2021

Submissions will be published on AusNet Services' website. If you do not wish to have your submission published, please clearly stipulate this at the time of lodging your submission.

1.4 Next steps

Following conclusion of the non-network options report consultation period, AusNet Services will, having regard to any submissions received on this non-network options report, prepare and publish a draft project assessment report (DPAR). AusNet Services intends to publish the DPAR by Q3 2021.

2 Introduction

The RIT-D is an economic cost-benefit test used to assess and rank potential investments capable of meeting the identified need. The purpose of the RIT-D is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option).

This non-network options report is the first stage of the RIT-D consultation process in relation to the existing and emerging service level constraints in the TGN supply area. This report has been prepared by AusNet Services in accordance with the requirements of clause 5.17 of the NER.

This report:

- Describes the identified need that AusNet Services is seeking to address, in relation to the service level constraints in the TGN Zone Substation supply area.
- Outlines the assumptions made in identifying the need.
- Describes the options that AusNet Services considers could potentially address the identified need.
- Outlines the technical characteristics that a non-network option would be required to deliver to meet the identified need.
- Invites registered participants, AEMO, interested parties, non-network providers and persons on AusNet Services' demand side engagement register to make a submission on this non-network options report.

3 Background

3.1 Existing network

TGN is located approximately 170km east of Melbourne (VicRoads map reference 343 M-7) and is the main source of supply for Traralgon, Glengarry, Calilgnee, Gormandale, Rosedale and surrounding areas. TGN is located at an elevation of 60m above sea level. TGN has a summer average maximum temperature of 26°C and a winter average minimum temperature of 4.1°C. Extreme temperatures reach 46.3°C in summer and -4.8°C in winter. The mean rain fall varies from 37.2mm to 60.1mm per month within a year.

TGN supplies approximately 17,500 customers. The load at TGN includes town and rural based residential, with some town based commercial, industrial and farming. The location of TGN within the AusNet Services distribution network is shown in Figure 1.

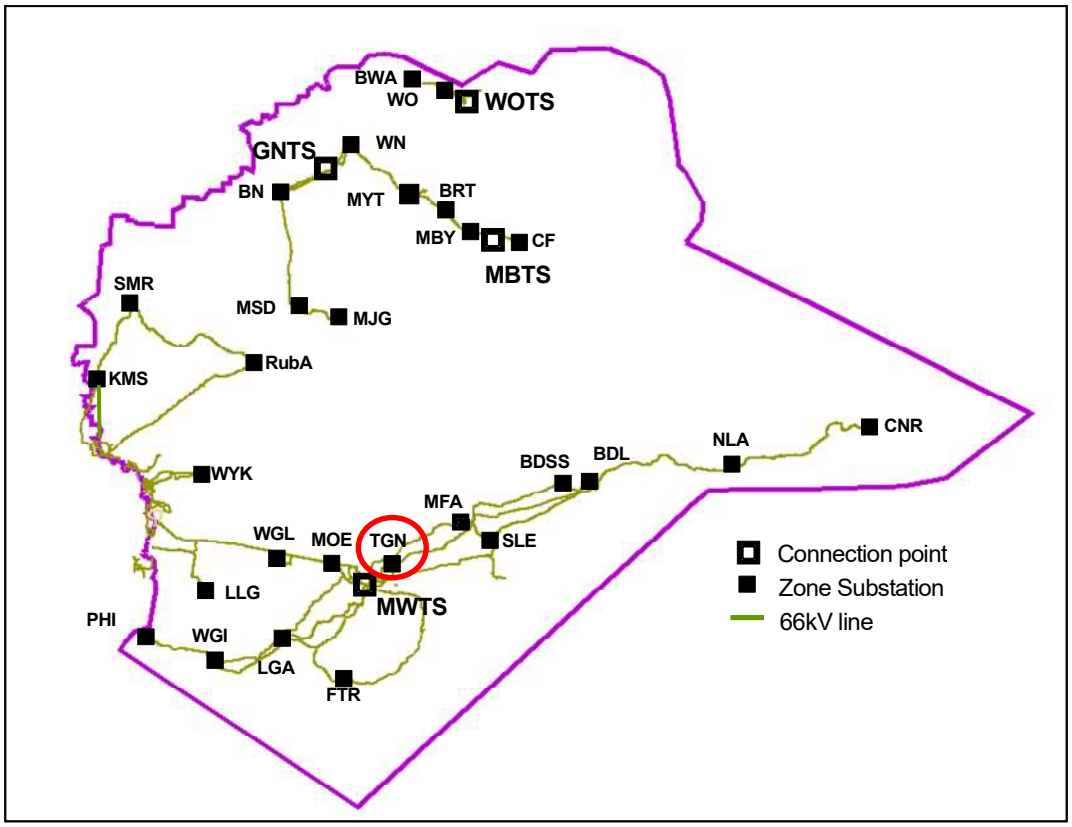

Figure 1: TGN location within AusNet Services network

TGN is supplied via three 66kV circuits, two of which come from Morwell Terminal Station (MWTS) and the third from Maffra Zone Substation.

The configuration of primary electrical circuits within TGN is as shown in the following single line diagram Figure 2.

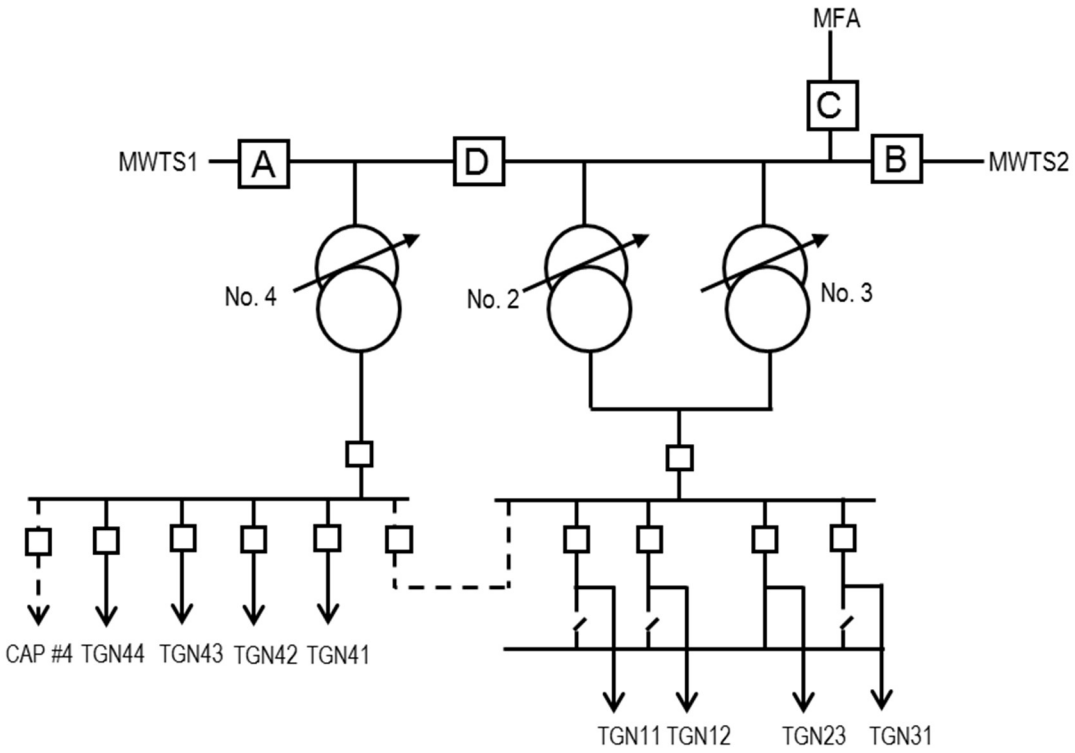

Figure 2: Single Line Diagram of TGN

3.2 Customer Composition

TGN has eight 22kV feeders supplying AusNet Services' customers. One of the feeders has a 10MW power station connected to it that has previously been used for network support, however the contract has now expired.

Table 1 provides detail of the 22kV supply feeders.

Table 1: TGN feeder information

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
TGN11	54	Summer peaking, short rural feeder	3,671	95% residential 2% commercial 1% industrial 2% farming.
TGN12	5	Summer peaking, urban feeder	466	50% residential 47% commercial 3% industrial.
TGN23	176	Summer peaking, short rural feeder	2,433	86% residential 4% commercial 1% industrial 9% farming
TGN31	346	Summer peaking, long rural feeder	1,981	62% residential 8% commercial 1% industrial 29% farming

Feeder	Feeder Length (km)	Feeder description	Number of Customers	Type of Customers
TGN41	337	Summer peaking, long rural feeder	1,805	57% residential 16% commercial 3% industrial 24% farming
TGN42	6	Summer peaking, urban feeder	629	35% residential 64% commercial 1% industrial
TGN43	24	Summer peaking, short rural feeder	3,884	97% residential 3% commercial
TGN44	32	Summer peaking, short rural feeder	2,611	96% residential 3% commercial 1% industrial and farming combined

The 22kV feeders interconnect with 22kV feeders from Morwell and Maffra zone substations. Approximately 9.7MVA of load is able to be transferred away from TGN to these stations via 22kV feeders, predominantly to Morwell.

3.3 Zone Substation Equipment

3.3.1 Primary Equipment

TGN includes an air insulated 66kV switchyard with four circuit breakers. It does not have a 66kV ring bus and is therefore more susceptible to bus faults impacting the station load. There are three air insulated outdoor 22kV busbars and a transfer bus supplying four 22kV feeders and one 9 MVAr capacitor bank.

The 66kV circuits are switched by two minimum oil 66kV circuit breakers ‘A’ and ‘B’ installed in 1977 and two dead tank 66kV circuit breakers, ‘C’ and ‘D’, installed in 2013.

There are four 22kV outdoor feeder circuit breakers manufactured between 1967 and 1969, one 22kV outdoor circuit breaker manufactured in 1983, two outdoor 22kV transformer circuit breakers installed in 2013 and the remaining indoor 22kV circuit breakers are part of an integrated 22kV switchboard installed in 2013.

Transformation comprises two 10/13.5 MVA 66/22kV transformers (No.2 and No.3), which are switched as a single group, and one 20/33 MVA 66/22kV transformer (No.1).

The No.2 and No.3 transformers were manufactured in 1949 and 1979 respectively. No.1 transformer was manufactured and installed in 2013.

3.3.2 Secondary Equipment

The 66kV line circuit breakers have circuit breaker failure and auto reclose schemes using Group relays. The 22kV feeder circuit breakers have overcurrent, earth fault and sensitive earth fault using modern numerical relays. The 22kV capacitor bank protection has neutral balance and capacitor control device functions using modern numerical relays.

The transformers have differential protection, voltage regulating and restrictive earth fault protection using old electronic relays. The bus protection has overcurrent and distance protection using old electronic relays.

4 Identified Need

TGN commenced operation as a 66/22kV transformation station in 1969. There are two 10/13.5 MVA transformers that were manufactured in 1949 and 1979. There is one 20/33 MVA transformer that was manufactured in 2012.

The 22kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22kV busses with four feeder CBs installed in 1969. The 66kV switchyard has had some modifications since the site was established, and now consists of two lines to MWTS and one line to Maffra Zone Substation. Two of the 66kV circuit breakers were installed in 1977 while the other two were installed in 2013 when the new 20/33 MVA transformer was installed.

The physical and electrical condition of these assets has deteriorated and they are now presenting an increasing failure risk. The station 66kV bus is partially switched, hence faults on the 66kV transformer bus or either one of the transformers could result in load shedding at TGN, or elsewhere in the East Gippsland network due to a reduction in 66kV supplies. Failure of the 66kV bus tie CB will result in loss of supply to all (approximately 17,500) customers supplied from TGN.

The key service constraints at TGN are:

a) Security of supply risk presented by the switching of the No.2 and No.3 transformers in a single group, and lack of 66kV ring bus;
b) Security of supply risks presented by increasing likelihood of asset failure due to the deteriorating condition of the assets;
c) Health and safety risks presented by a possible explosive failure of bushings on a number of the assets;
d) Plant collateral damage risks presented by a possible explosive failure of a number of the assets;
e) Environmental risks associated with insulating oil spill or fire;
f) Reactive asset replacement risks presented by the increasing likelihood of asset failure due to the deteriorating condition of the assets;
g) Health and safety risks presented by exposed live terminals at the rear of the secondary panels in the control room; and
h) Health and safety risks presented by asbestos containing cement sheets or electrical switch boards in the control building, store room and toilet.

5 Assumptions underpinning the identified need

The purpose of this chapter is to summarise the key input assumptions that underpin the identified need described in the previous chapter.

5.1 Regulatory Obligations

In addressing the identified need, we must satisfy our regulatory obligations, which we summarise below.

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to only propose capital expenditure required in order to achieve each of the following:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services, and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Section 98(a) of the Electricity Safety Act requires AusNet Services to:

design, construct, operate, maintain and decommission its supply network to minimise as far as practicable –

(a) the hazards and risks to the safety of any person arising from the supply network; and

(b) the hazards and risks of damage to the property of any person arising from the supply network; and

(c) the bushfire danger arising from the supply network.

The Electricity Safety act defines 'practicable' to mean having regard to –

(a) severity of the hazard or risk in question; and

(b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and

(c) availability and suitability of ways to remove or mitigate the hazard or risk; and

(d) cost of removing or mitigating the hazard or risk.

Clause 3.1 of the Electricity Distribution Code requires AusNet Services to:

(b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:

(i) to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;

(ii) to minimise the risks associated with the failure or reduced performance of assets; and

(iii) in a way which minimises costs to customers taking into account distribution losses.

Under clause 5.2 of the Electricity Distribution Code, AusNet Services:

> *must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

5.2 Asset Condition

AMS 10-13 Condition Monitoring describes AusNet Services' strategy and approach to monitoring the condition of assets.

Asset condition is measured with reference to an asset health index on a scale of C1 to C5. Table 2 provides a description of the asset condition scores.

Table 2: Asset Condition Score and Remaining Service Potential

Condition Score	Condition	Condition Description
C1	Very Good	Initial service condition
C2	Good	Deterioration has minimal impact on asset performance. Minimal short term asset failure risk.
C3	Average	Functionally sound showing some wear with minor failures, but asset still functions safely at adequate level of service.
C4	Poor	Advanced deterioration – plant and components function but require a high level of maintenance to remain operational.
C5	Very Poor	Extreme deterioration approaching end of life with failure imminent.

The condition of the key assets at TGN is discussed in the Asset Health Reports for the key asset classes such as power transformers, instrument transformers and switchgear with information on asset condition rankings, recommended risk mitigation options and replacement timeframes. A summary of the asset condition at TGN is provided in Table 3 and discussed in the following sections.

Table 3: TGN Asset Condition Summary

Asset Type	Number of assets by Condition Score				
	C1	C2	C3	C4	C5
66kV Circuit Breakers	2			2	
66kV Current Transformers	6				
66kV Voltage Transformers	3				6
66/22kV Power Transformers	1		1	1	
22kV Circuit Breakers	11		1	1	3
22kV Current Transformers	21				5
22kV Voltage Transformers	1	3		1	

These condition scores are then used to calculate the asset failure rates using the Weibull parameters determined for each asset class.

5.3 Zone Substation Supply Capacity

TGN is a summer peaking station and the peak electrical demand reached 40.8MVA in the summer of 2019/20. The recorded peak demand during the winter of 2020 was 32.7MVA.

The demand at TGN is forecast to grow at approximately 0.9% per annum. Figure 3 shows the forecast maximum demand and supply capacities (cyclic ratings) for TGN.

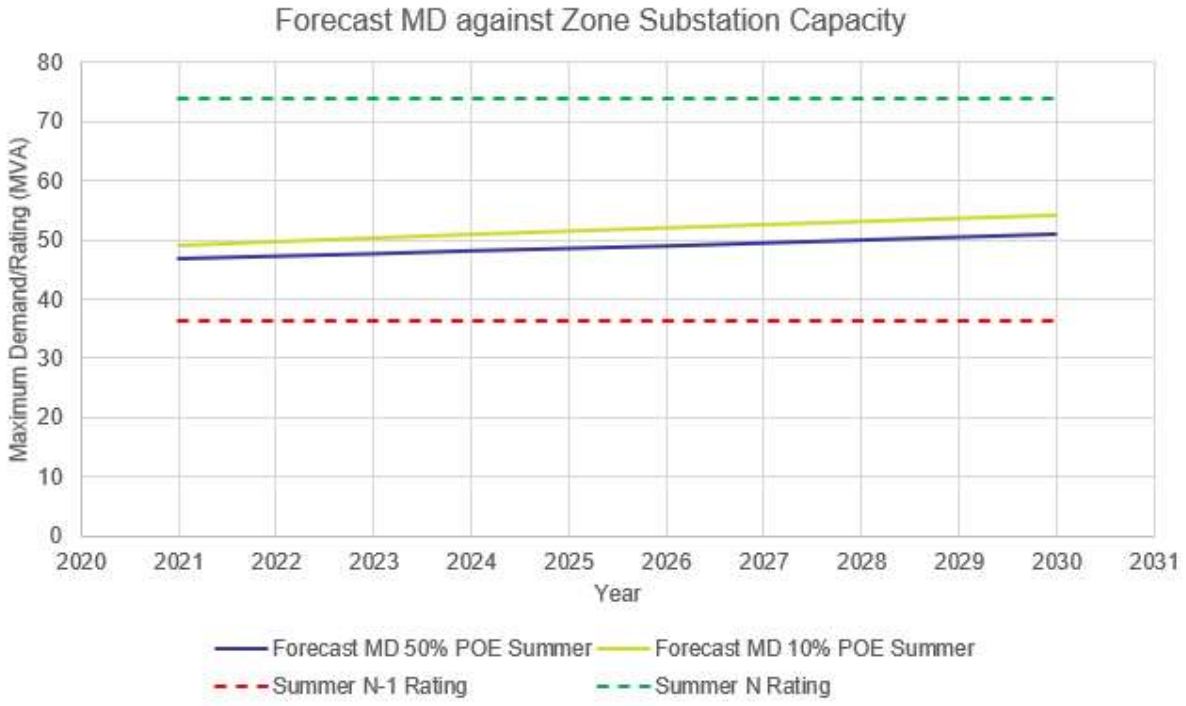

Figure 3: TGN Forecast Maximum Demand against Zone Substation Capacity

5.4 Load Duration Curves

The zone substation load duration curves that feed into the risk-cost assessment model are derived from historical actual demands between:

- 1 October 2019 and 31 March 2020 for the summer 50% probability of exceedance (POE) curves;
- 1 April 2020 and 30 September 2020 for the winter 50% POE curves;
- 1 October 2019 and 31 March 2020 for the summer 10% POE curves; and
- 1 April 2020 and 30 September 2020 for the winter 10% POE curves.

The historical hourly demands are separated by season and unitised based on the recorded maximum demand within that season (summer and winter) and time period, which allows the load duration curve to be scaled according to the seasonal forecast maximum demand for each year of the assessment period.

The 50% POE utilised load duration for TGN zone substation is presented in Figure 4, and the 10% POE unitised load duration for TGN zone substation is presented in Figure 5.

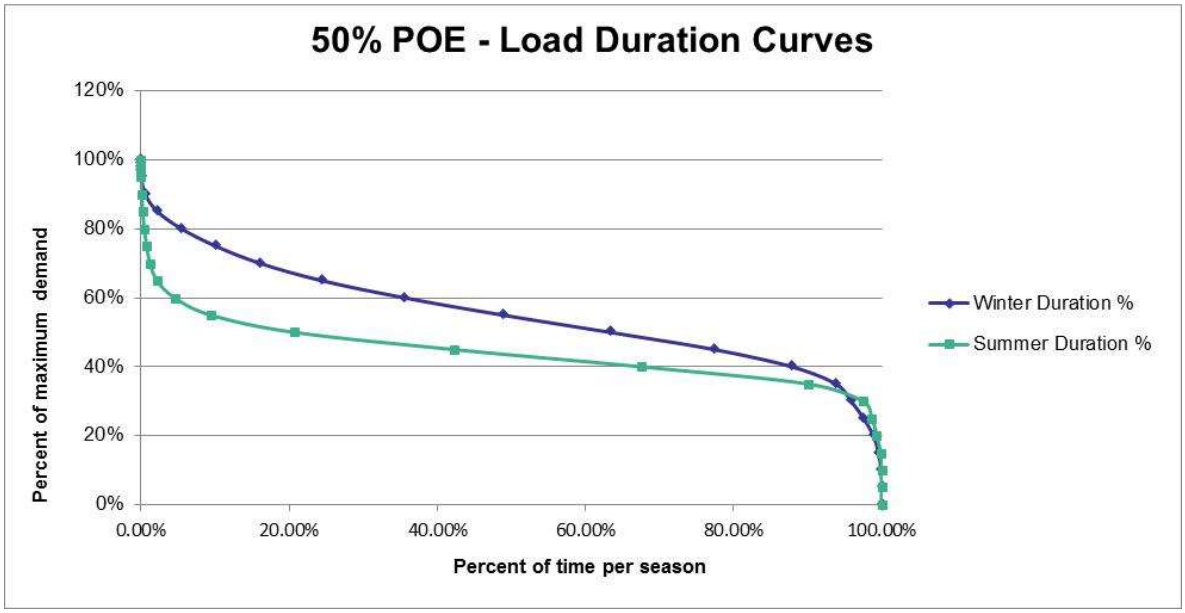

Figure 4: TGN 50% Load Duration Curves

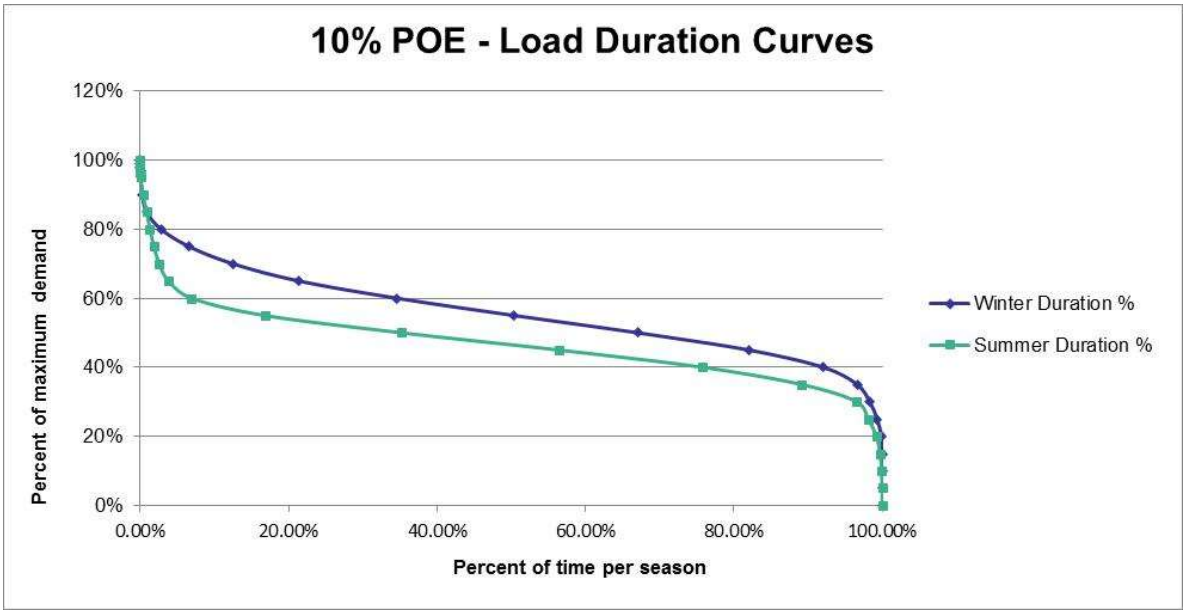

Figure 5: TGN 10% POE Load Duration Curves

5.5 Feeder Circuit Supply Capacity

There is currently no requirement for additional feeders at TGN due to the modest load growth expected in the area.

5.6 Load Transfer Capability

The Distribution Annual Planning Report (DAPR) provides the load transfer capability (in MW) of the feeder interconnections between TGN and its neighbouring zone substations. Our forecast load transfer capability for TGN is set out in Table 4.

Table 4: TGN Load Transfer Capability

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Transfer Capability (MW)	9.7	9.6	9.5	9.4	9.3	9.3	9.2	9.1	9.0	8.9

5.7 Station Configuration Supply Risk

The configuration of TGN mean that failure of some 66kV and 22kV equipment will result in supply outages to customers, as backup circuit breakers operate to isolate the failed equipment. The resultant supply outage would be for an estimated duration of two hours, which is the time typically required by operators to travel to site and manually re-configure circuits to isolate the failed equipment and sequentially restore supply to customers.

Table 5 lists the estimated bus outage consequence factors for each major type of equipment based on the substation layout.

Table 5: TGN Bus Outage Consequence Factors

Equipment	Estimated Bus Outage Consequence
Transformer	0%
22kV circuit breaker	54%
66kV circuit breaker	25%
22kV current transformer	54%
66kV current transformer	25%
22kV voltage transformer	56%
66kV voltage transformer	0%

6 Credible options

This section outlines the potential options that have been considered to address the identified need, and summarises the key works and costs associated with implementing these options.

It presents both the credible and non-credible options considered, and, where relevant, outlines why particular option(s) are considered non-credible.

The following options have been identified to address the risk at TGN:

1. Do Nothing (counterfactual)
2. Retire one transformer
3. Retire one transformer and reduce residual risk through network support
4. Network support to defer retirement and replacement
5. Replace 22kV switchgear with new switchboard
6. Replace two 66kV circuit breakers and 22kV switchgear
7. Integrated replacement

The purpose of this non-network options report is to provide an opportunity for non-network proponents to propose solutions. The options described in this section, therefore, should not be regarded as limiting the scope of potential non-network options.

6.1 Option 1: Do Nothing

The Do Nothing (counterfactual) option assumes that AusNet Services would not undertake any investment, outside of the normal operational and maintenance processes. Under this option, increasing supply risk would be managed by increased levels of involuntary load reduction. Increased non-supply risks, such as those associated with safety, collateral damage, reactive replacement and environmental impacts, would be accepted as unmanaged rising risk costs.

The Do Nothing (counterfactual) option establishes the base level of risk, and provides a basis for comparing other credible options. Whilst the direct capital costs of this option are zero, the continued exposure to residual risks means that this option has significant risk costs associated with it.

6.2 Option 2: Retire one transformer

This option tests whether the current installed capacity of the substation is still required to meet customer demand and whether equipment could be retired rather than replaced.

The estimated capital cost for this option is $100k, for associated decommissioning works.

6.3 Option 3: Retire one transformer and reduce residual risk through network support

This option supplements Option 2 by examining whether the addition of network support would provide a cost effective means of eliminating residual risk and therefore produce a higher net market benefit. The cost of obtaining network support will be the principal direct cost associated with this option, with capital expenditure of approximately $130k for the associated decommissioning works and setting up a network support agreement.

The purpose of this non-network options report is to test with non-network proponents whether this option is feasible and to better understand the likely costs of procuring network support. The details of the technical requirements for network support and the maximum available funding is discussed in the next section.

6.4 Option 4: Network support to defer retirement and replacement

This option extends Option 3 to consider whether sufficient network support could be provided to avoid entirely the proposed retirement and replacement of the network assets, i.e. a network support only solution.

As noted in relation to Option 3, this option will involve relatively modest direct costs to decommission assets and set up a network support agreement. The principal costs of this option, which is to be explored with non-network proponents, is the cost of procuring network support. Further information to assist non-network proponents is provided in the next section.

6.5 Option 5: Replace 22kV switchgear with new switchboard

Under this option only the 22kV outdoor switchgear will be replaced with a new 22kV indoor switchboard. The estimated capital cost of this option is $4.3 million.

6.6 Option 6: Replace two 66kV circuit breakers and 22kV switchgear

Under this option the 22kV outdoor switchgear will be replaced with a new 22kV indoor switchboard and two 66kV circuit breakers will be replaced,

The estimated capital cost of this option is $5.62 million.

6.7 Option 7: Integrated replacement

Under this option the deteriorated No.2 and No.3 transformers will be replaced with new 15/20 MVA units.

The outdoor 22kV switchgear will be replaced with a new indoor 22kV switchboard.

The 66kV bus will be fully switched to further improve reliability.

The estimated capital cost of this option is $9.51 million.

7 Requirements for non-network option

This section outlines:

- The technical characteristics that a non-network (network support generation, energy storage and/or demand management) option would be required to deliver; and
- The information that a non-network proponent should provide to AusNet Services to explore the potential provision of a non-network service.

The amount that AusNet Services would be willing to pay for a non-network service depends on the extent to which it will mitigate the risks described in the identified need. Key factors that influence the network support amount payable to proponents include availability, capacity, dispatch duration and firmness of response provided by the non-network solution.

7.1 Load reduction and location

As detailed in section 4, the identified need comprises a number of different elements, which can be grouped together in the following broad categories:

- Security of supply risk;
- Health and safety risks;
- Plant collateral damage risks;
- Environmental risks; and
- Reactive asset replacement risks.

In broad terms, these risks are asset-related and will only be mitigated by a non-network option if it is able to reduce the existing dependency on the relevant assets. For asbestos related risks associated with TGN, for example, it is highly unlikely that these risks can be mitigated by a non-network option (as the risk relates to the fabric of the building).

However, if the need for one or more transformers or other assets can be eliminated through a non-network option, then savings may result by reducing the risks associated with asset failure. The ability for a non-network solution to support an N-1 contingency on a summer peak demand day is one such scenario.

The table below sets out the load reductions that a non-network option would be required to deliver on a maximum demand day, in order to mitigate the identified risks at TGN to some extent, e.g. loss of one transformer.

Table 6: Load at risk and non-network support requirements

Year	Load at Risk (MVA)	Hours at Risk, POE50	Expected non-network support required during MD event	
			MW @ PF = 1	MWh
2021/22	1.5	0.7	1.5	1.8
2022/23	2.0	1.0	2.0	2.7
2023/24	2.6	2.0	2.6	4.0
2024/25	3.1	2.8	3.1	5.4
2025/26	3.5	3.6	3.5	7.0
2026/27	4.1	4.6	4.1	9.2
2027/28	4.7	6.1	4.7	11.7
2028/29	5.3	7.6	5.3	14.2
2029/30	5.8	9.1	5.8	17.0

If non-network options are able to reduce the load by more than this minimum amount under an N-1 scenario, then the level of risk mitigation is likely to be higher.

7.2 Power system security, reliability and fault levels

A non-network option must be capable of reliably meeting electricity demand under a range of conditions and scenarios. The non-network solution will contribute to system security and reliability to the extent that it addresses the risks arising from the identified need. The non-network option is not required to address any existing issues in relation to fault levels.

If the non-network option is a rotating or inverter-based generator operating in parallel with AusNet Services' network, the generator must comply with the requirements set out in document SOP 33-05 and other connection requirements which are set out in AusNet Services' embedded generator connections page.

7.3 Timing and operating profile

A non-network option would need to be agreed by 30 November 2021 in order to defer the adoption of a network solution. AusNet Services' expectation is that a non-network solution would be required for a minimum of five (5) years, although the duration of the service would be subject to negotiation.

A non-network option must, as a minimum, be capable of reducing network loading or increasing network capacity in the TGN supply area during the months of December to March (summer period). For each day during this period, the network load reduction or increase in network capacity would be required over the evening period, typically 5 pm to 8 pm (AEST), as shown in Figure 6.

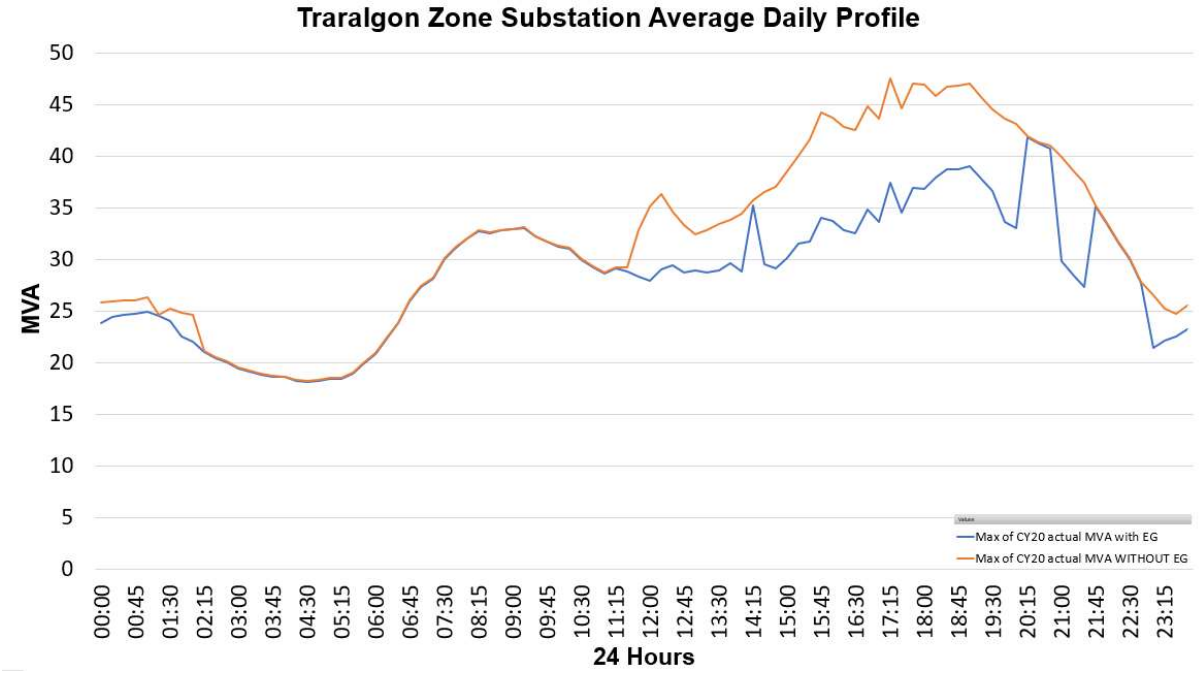

Figure 6: Average 24-hour Demand Profile, Showing Timing of Peak Demand

The maximum duration of non-network support required over a day can be up to four consecutive hours per day. The non-network solution will need to be capable of operating continuously during these periods on consecutive days, to cater to peak demands until the faulted asset is repaired or replaced, and full N-rated capacity is restored at the zone substation.

7.4 Guidance on potentially feasible options

The following non-network solutions are likely to be potentially feasible options to address the identified need:

- New embedded generation;
- Existing customer generation and load curtailment (firm demand management); and
- Embedded energy storage systems.

Without limiting the potential for non-network solutions, the following types of non-network options are unlikely to be feasible:

- Renewable generation not coupled with storage or dispatchable generation; and
- Unproven, experimental or undemonstrated technologies.

7.5 Data requirements from non-network service providers

Non-network service providers interested in alleviating the network constraints outlined above are advised to begin engagement with AusNet Services as soon as possible. A detailed proposal including the information listed below should be submitted by the requested date. Details required include:

- Name, address and contact details of the person making the submission.
- Name, address and contact details of the person responsible for non-network support (if different to above).
- A detailed description of the services to be provided, including:

  - Size and capacity (MW/MVA/MWh).
  - Location(s).
  - Frequency and duration.
  - Type of action or technology proposed, including response / ramp rate information, where applicable.
  - Proposed dispatching arrangement (e.g. telephone, web-based trigger, automated means via RTU).
  - Availability and reliability performance details.
  - Period of notice required to enable dispatch of non-network support (e.g. to allow time for charging of energy storage solutions or market-based limitations).
  - Proposed contract period and staging (if applicable).
  - Proposed timing for delivery (including timeline to plan and implement the proposal).
- High-level electrical layout of the proposed site (if applicable).
- Evidence and track record proving capability and previous experience in implementing and completing projects of the same type as the proposal.
- Preliminary assessment of the proposal's impact on the network.
- Breakdown of the lifecycle costs for providing the service, including:
  - Capital costs (if applicable).
  - Annual operating (i.e. set up and dispatch fees) and maintenance costs.
  - Other costs (e.g. availability, project establishment, etc.).
  - Tariff assumptions.
- A method outlining measurement and quantification of the agreed service, including integration of the proposed solution with the network.
- A statement outlining that the non-network service provider is prepared to enter into a Network Support Agreement (NSA) (subject to agreeing terms and conditions).
- Letters of support from partner organisations.
- Any special conditions to be included in an NSA.

All proposals must satisfy the requirements of any applicable laws, rules, and the requirements of any relevant regulatory authority, including following the normal network connection processes where applicable. Any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent of the non-network solution.

For further details on AusNet Services' process for engaging and consulting with non-network service providers, and for investigating, developing, assessing and reporting on non-network options as alternatives to network augmentation, please refer to the Non-Network Solutions and Demand Management webpages, which contain the Demand Side Engagement Strategy and other relevant demand management documentation:

https://www.ausnetservices.com.au/Electricity

7.6 Potential payments to non-network proponents

As already noted, the maximum amount that AusNet Services would be willing to pay for a non-network solution would depend on the value that it provides in terms of risk reduction. The actual payment to a non-network proponent will be subject to negotiation.

Provisional analysis indicates that Option 7 is the preferred network option. If this option could be deferred *entirely* by engaging a non-network solution, the total capital expenditure of approximately $9.51 million could be deferred. The approximate maximum annual payment that would be available to a non-network proponent to defer this expenditure would be in the region of $660 k per annum. This calculation assumes a 45 year asset life, an operating expenditure allowance of 1% of the avoided network capital expenditure, and a cost of capital of 5.9% (real).

It should be emphasised, however, that the actual payment for a non-network solution may be lower than this maximum available amount, due to the aforementioned factors of availability, capacity, dispatch duration and firmness of response provided by the non-network solution.

8 Next Steps

The assessment outlined in this report shows that the service level risk to customers supplied from TGN is forecast to grow to unacceptable levels within the 2021-25 EDPR period.

The forecast increase in service level risk is driven by increasing supply and non-supply (safety, environmental, collateral damage and reactive replacement) risk due to deterioration in the condition of the assets resulting in an increasing likelihood of asset failure. AusNet Services considers that one of the credible options outlined in this report, or an alternative non-network option will be required to address the identified need.

8.1 Request for submissions

AusNet Services invites written submissions, on the matters set out in this non-network options report, from Registered Participants, AEMO, interested parties, non-network providers and those registered on our demand-side engagement register.

All submissions and enquiries should be directed to:

Fuji Dinh
Senior Engineer – Strategic Network Planning
AusNet Services
Email: ritdconsultations@ausnetservices.com.au

Submissions are due on or before 20 August 2021.

Submissions will be published on AusNet Services' website. If you do not wish to have your submission published, please clearly stipulate this at the time of lodging your submission.

8.2 Next stage of RIT-D process

Following conclusion of the non-network options report consultation period, AusNet Services will, having regard to any submissions received on this non-network options report, prepare and publish a draft project assessment report (DPAR) including:

- A summary of, and commentary on, any submissions on the non-network options report.
- A detailed market benefit assessment of the proposed credible options to address the identified need.
- Identification of the proposed preferred option to meet the identified need.

AusNet Services expects to publish the DPAR by Q3 2021.