Jemena Electricity Networks (Vic) Ltd

Somerton Zone Substation (ST) Supply area Capacity Constraint

RIT-D Stage 1: Options Screening Report

Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Our customers expect us to deliver a reliable electricity supply at an efficient cost. To do this, we must choose the most efficient solution to address current and emerging network limitations. This means choosing the prudent solution that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**).

Identified Need

Somerton (**ST**) zone substation is owned and operated by JEN, providing power to approximately 19,331 customers in Melbourne's outer north. ST supplies both the residential areas of Craigieburn, Roxburgh Park, and Greenvale to the west of the Hume Highway, and a mixture of industrial and commercial load predominantly located on either side of the highway in the Somerton and Campbellfield areas. The adjacent area of Coolaroo to the west is supplied by JEN's Coolaroo (**COO**) zone substation, and the adjacent area of Mickleham to the north is supplied by AusNet's Kalkallo (**KLO**) zone substation.

ST, COO and KLO are the main sources of supply to the Northern Growth Corridor of Melbourne, and all are experiencing high growth and high utilisations. The available spare capacity provided by ST and its distribution feeders (ST 11, ST 12, ST 22, ST 32 and ST 33), including that of the adjacent feeders providing support for the area (i.e., COO23, KLO13, KLO21 and KLO22), is declining over time. As such this will have increasing consequences for the reliability of electricity supply to JEN's customers within the supply area.

The identified need for this Regulatory Investment Test for Distribution (**RIT-D**) is to maintain the reliability of supply in the Somerton supply area whilst accommodating new customer connections, and growth in customer maximum demand.

Approach to screening options

JEN has developed a set of potential network solutions aimed at addressing the identified need. JEN has also investigated whether viable non-network or stand-alone power system (**SAPS**) solutions exist, in which case JEN is required to publish an options screening report and request stakeholder submissions, as detailed in National Electricity Rules (**NER**) clause 5.17.4, paragraph (e).

However, in the event that there are no potential credible non-network or SAPS options that could address the identified need (or any combination of those options with or without a network option), JEN is instead required to publish a Notice of Determination in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the NER.

This report considers the credibility of potential non-network and SAPS options as alternatives to, or supplements for the identified network options to meet the identified need. This is in the context of a non-network or SAPS option being able to supply any shortfalls in ST, COO and the relevant feeders meeting their forecast demand during the 10-year planning horizon.

The minimum level of network support required for the underlying growth in customer maximum demand for the supply area is up to 30 MW over the 10-year period. Smaller (or staged) solutions of at least 4 MW (per annum cumulative), could provide sufficient capacity to address this part of the identified need.

There is an additional level of network support required for the growth in maximum demand of major customers at (or in proximity to) their site in Craigieburn, being up to 33 MW over the 10-year period. Smaller (or staged) non-network or SAPS solutions of at least 3 MW (per annum cumulative), could provide sufficient capacity to address this part of the identified need.

Summary of findings

The criteria used by JEN to assess the potential credibility of non-network and SAPS options included:

- **Addressing the identified need**: reducing or eliminating the supply reliability risks associated with the identified need.
- **Being technically feasible**: there are no technical constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 1–1 shows the rating scale JEN has applied for assessing credibility of non-network and SAPS options.

Table 1–1: Assessment criteria rating

Rating	Colour Coding
Does not meet the criterion	
Does not fully meet the criterion (or uncertain)	
Clearly meets the criterion	

Table 1–2 shows the initial assessment of potential non-network and SAPS options against the RIT-D criteria.

Table 1–2: Assessment of non-network options against RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Economic	Timing
1.0 Generation and Storage				
1.1 Generation using gas turbines or diesel				
1.2 Generation using grid-scale solar and storage				
1.3 Standby generation (existing large customer)				
1.4 Storage only using grid-scale batteries				
2.0 Demand Management				
2.1 Customer power factor correction				
2.2 Customer solar power and storage systems				
2.3 Broad-based demand response				
2.4 Targeted demand response				

Based on these results, JEN has concluded that some of the potential non-network or SAPS options investigated (or a combination of options) could represent technically or economically feasible alternatives to adequately address the identified need.

Hence, under NER clause 5.17.4(b), JEN has published this options screening report as part of the first phase of consultation under the RIT-D, which details the content listed under NER clause 5.17.4(e).

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Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
Contingency (or 'N-1' condition)	An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
Energy-at-risk	The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Expected unserved energy (EUE)	Refers to an estimate of the probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 370,000 customers covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt Ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit.
Network	Refers to the system of physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's capability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	An economic viability test that establishes consistent, clear and efficient planning processes for assessing and consulting on distribution network investments over a prescribed limit.
Stand Alone Power System	An embedded power system that operates disconnected (islanded) from the network.
System Normal (or 'N' condition)	The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration.
Value of Customer Reliability (VCR)	Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
Zone Substation	Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the network.

10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

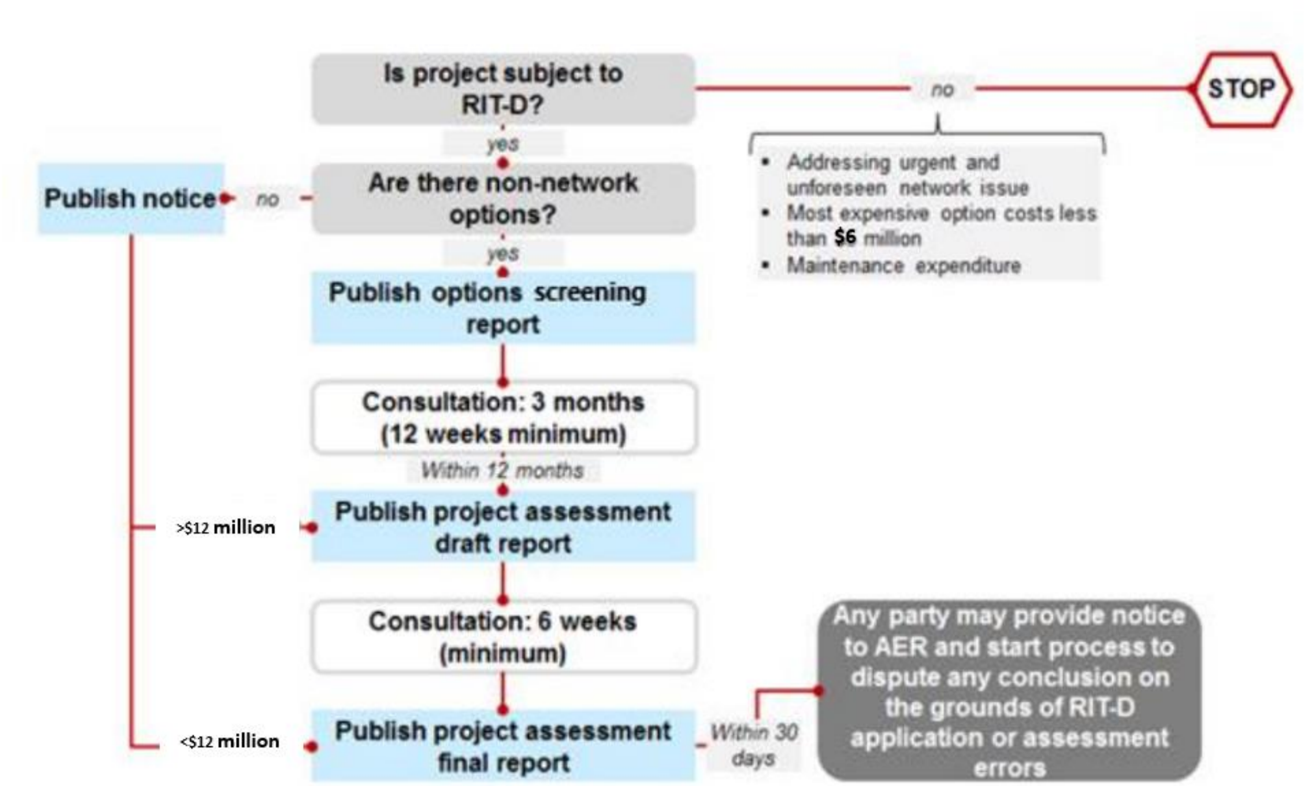
Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CB	Circuit Breaker
CBN	Craigieburn Zone Substation (future)
CBRM	Condition Based Risk Management
COO	Coolaroo Zone Substation
DPAR	Draft Project Assessment Report
EUE	Expected Unserved Energy
GVE	Greenvale Zone Substation (future)
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
KLO	Kalkallo Zone Substation (AusNet)
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System normal condition
N-1	Single contingency condition
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand Alone Power System
ST	Somerton Zone Substation
VCR	Value of Customer Reliability

1. Introduction

Distribution businesses are required to undertake a process (the Regulatory Investment Test for Distribution, or "**RIT-D**") to identify investment options which best address an identified need on the electricity distribution network. The RIT-D applies in circumstances where a network limitation (an "identified need") exists (that is not reliability corrective action) and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $6 million[1]. As part of the RIT-D process, distribution businesses must also consider non-network and standalone power system (**SAPS**) options when assessing credible options to address the identified need. The RIT-D process is summarised in Figure 1–1.

Figure 1–1: The RIT-D Process[2]



Under the RIT-D consultation process, distribution businesses are required to screen for non-network and SAPS options by determining whether they are likely to form a:

- Potential credible option(s) or;
- Significant part of one or more potential credible options to address the identified need.

This options screening report:

- Summarises the non-network and SAPS screening requirements and the assessment approach (Section 2).
- Describes the identified need JEN is aiming to address (Section 3).
- Describes the network options tested to date (Section 4).
- Describes the potential of non-network and/or SAPS options to help address the identified need (Section 5).

[1] Source: AER 2021 RIT and APR cost thresholds review (November 2021).

[2] Source: AER Application Guidelines RIT-D (August 2022).

- States the conclusion reached on potential non-network and SAPS options, and next steps (Section 6).

2. Screening requirements and approach

This section:

- Defines the option screening requirements as set out in the:
  - AER RIT-D Application guidelines (**Application Guidelines**), Dated August 2022; and
  - National Electricity Rules (**NER**), Version 214, Dated 11th July 2024.
- Describes the approach to assessing the credibility of non-network and SAPS options.

2.1 Definitions

Non-network and SAPS options include (from Application Guidelines Section 6.1):

- Any measure or program targeted at reducing peak demand (e.g. direct load control schemes, broad-based or targeted demand response programs)
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity)

An **identified need** is defined in Chapter 10 of the NER as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network. According to the Application Guidelines Section 3.1, an identified need may be addressed by either a network, non-network or SAPS option and:

- May involve meeting any of the service standards linked to the technical requirements of schedule 5.1 of the NER, or in applicable regulatory instruments (reliability corrective action) and/or an increase in the sum of consumer and producer surplus in the NEM.
- RIT-D proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

In describing an identified need, a RIT-D proponent may find it useful to explain what will or may happen if the RIT-D proponent fails to take any action (Application Guidelines Section 3.1).

A **credible option** is defined in clause 5.15.2(a) of the NER as an option, or group of options that:

- Addresses the identified need;
- Is (or are) economically and technically feasible; and
- Can be implemented in sufficient time to meet the identified need.

Clause 5.15.2(c) conveys that: In applying the RIT-D, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- Energy source;
- Technology;
- Ownership; and
- Whether it is a network, non-network or SAPS solution.

JEN has interpreted the guidance to mean that a credible option could consist of a non-network component and a network component which, when combined, meet the identified need. For example, where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (Application Guidelines, Example 22, page 74).

2.2 Approach

JEN's approach to identifying and assessing the credibility of potential non-network and SAPS options for this options screening report includes:

- Describing the identified need, by the network limitations driving the proposed investment including the capacity, demand and the minimum contribution required if non-network options are to be potentially credible.
- Describing the credible network options that address the identified need, with a preliminary designation of the preferred network solution.
- Documenting an initial assessment of the range of non-network options against the criteria in clause 5.15.2(a) of the NER described above.
- Concluding whether there is sufficient and appropriate evidence to determine if there are any potential credible non-network or SAPS options, identifying any issues that require further examination.

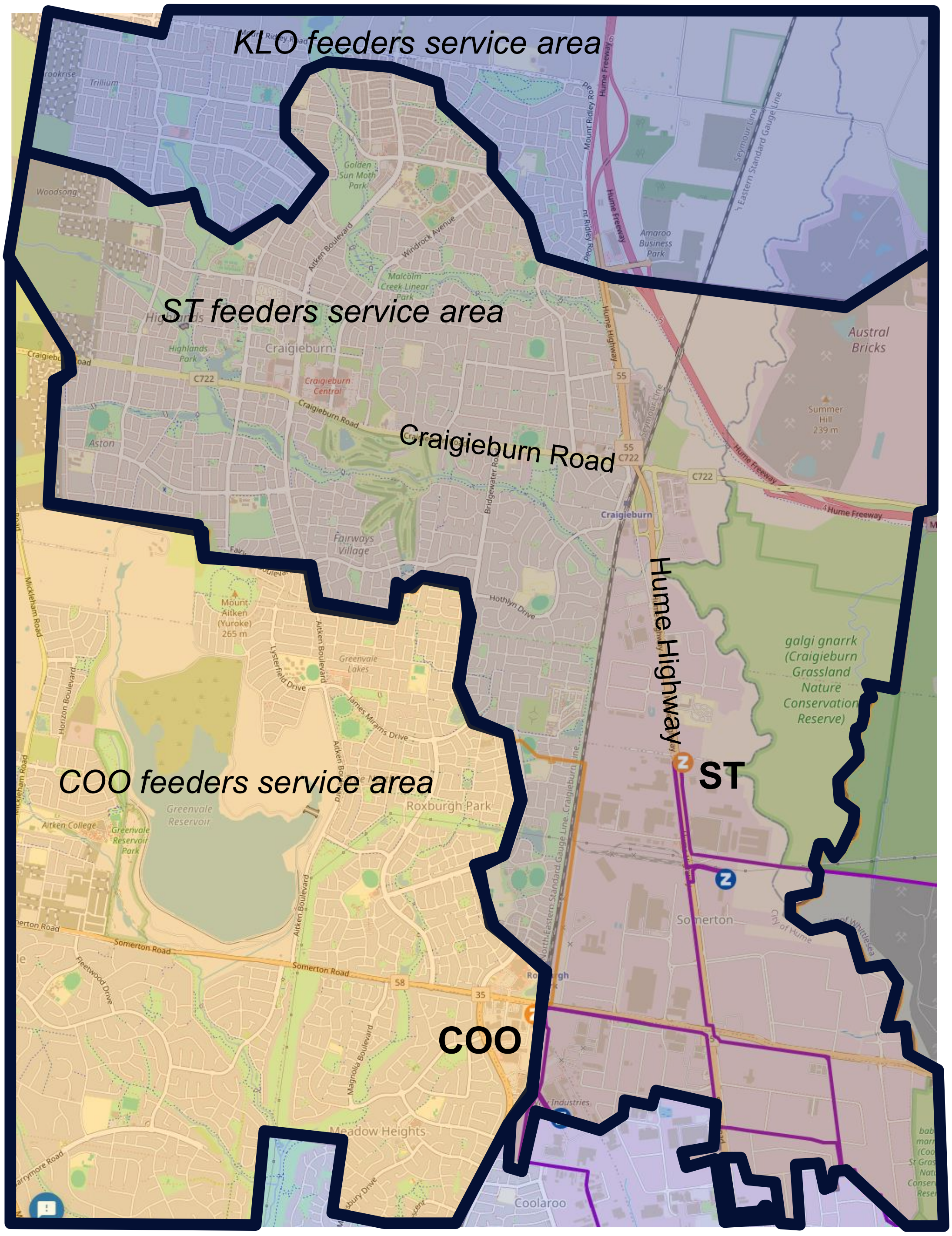
3. Identified need

3.1 Description of the identified need

Somerton (**ST**) zone substation is owned and operated by JEN, providing power to approximately 19,331 JEN customers in Melbourne's outer north. ST supplies both the residential areas of Craigieburn, Roxburgh Park, and Greenvale to the west of the Hume Highway, and a mixture of industrial and commercial load predominantly located on either side of the highway in the Somerton and Campbellfield areas. The adjacent area of Coolaroo to the west is supplied by JEN's Coolaroo (**COO**) zone substation, and the adjacent area of Mickleham to the north is supplied by AusNet's Kalkallo (**KLO**) zone substation.

Figure 3–1 shows the geographic supply area of ST, COO and JEN's KLO feeders.

Figure 3–1: Somerton supply area



ST, COO and KLO are the main sources of supply to the Northern Growth Corridor[3] of Melbourne, and all are experiencing high growth and high utilisations. The available spare capacity provided by ST and its 22 kV distribution feeders (ST 11, ST 12, ST 22, ST 32 and ST 33), including that of the adjacent feeders providing support for the area (i.e., COO23, KLO13, KLO21 and KLO22), is declining over time. As such, the high growth and high asst utilisation will have increasing consequences for the reliability of electricity supply to JEN's customers within the Somerton supply area.

Therefore, the identified need for this RIT-D is to maintain the reliability of supply in the Somerton supply area whilst accommodating new customer connections, and growth in customer maximum demand.

JEN has prepared this options screening report to assess whether the reliability needs of the Somerton supply area could be realised either fully, or in part through non-network or SAPS options, and to consult with the market on seeking such solutions for addressing the identified need.

3.2 Assumptions used in identifying the identified need

JEN's planning standard for reliability of supply is based on a probabilistic planning approach which estimates the Expected Unserved Energy (**EUE**) in megawatt hours (MWh) per annum of customer supply interruptions. The EUE is expressed financially by multiplying it with a Value of Customer Reliability (**VCR**) ($/MWh). JEN uses this approach to identify, quantify and prioritise investment in the distribution network. Typically, the EUE is calculated through understanding the load-at-risk for each network asset with an identified capacity limitation. This is normally calculated through modelling load-at-risk under system normal, and if any single item of equipment is out of service (called a normal minus one or N-1 scenario, i.e., a contingency condition), taking into account the probability of an asset failure and its restoration times. The value of the EUE will depend on the topology and capacity of the existing network and the forecast demand. For the Somerton supply area, this presented below in Sections 3.2.1 and 3.2.2.

3.2.1 Network capacity

The zone substation assets limiting the summer and winter capacity at ST are the 66/22 kV power transformer and transformer 22kV circuit breaker thermal limits. Also, the existing 22 kV buses are fully utilised meaning they can't support additional feeders to meet increasing demand within the Somerton supply area.

ST consists of three 66/22 kV 20/33 MVA power transformers, and 12 x 22 kV feeders from three 22 kV indoor bus switchboards. The total system normal (N) secure rating of the zone substation is 95.2 MVA. The single contingency (N-1) rating is based on the transformer cyclic ratings, assuming one transformer is out of service. This gives an N-1 rating of 79.7 MVA (summer) and 89.3 MVA (winter). ST is currently fully built out to its ultimate configuration.

The load transfer capacity away from ST is currently 9.5 MVA, however with the high growth in the area, this level is expected to deteriorate by approximately 1 MVA per annum.

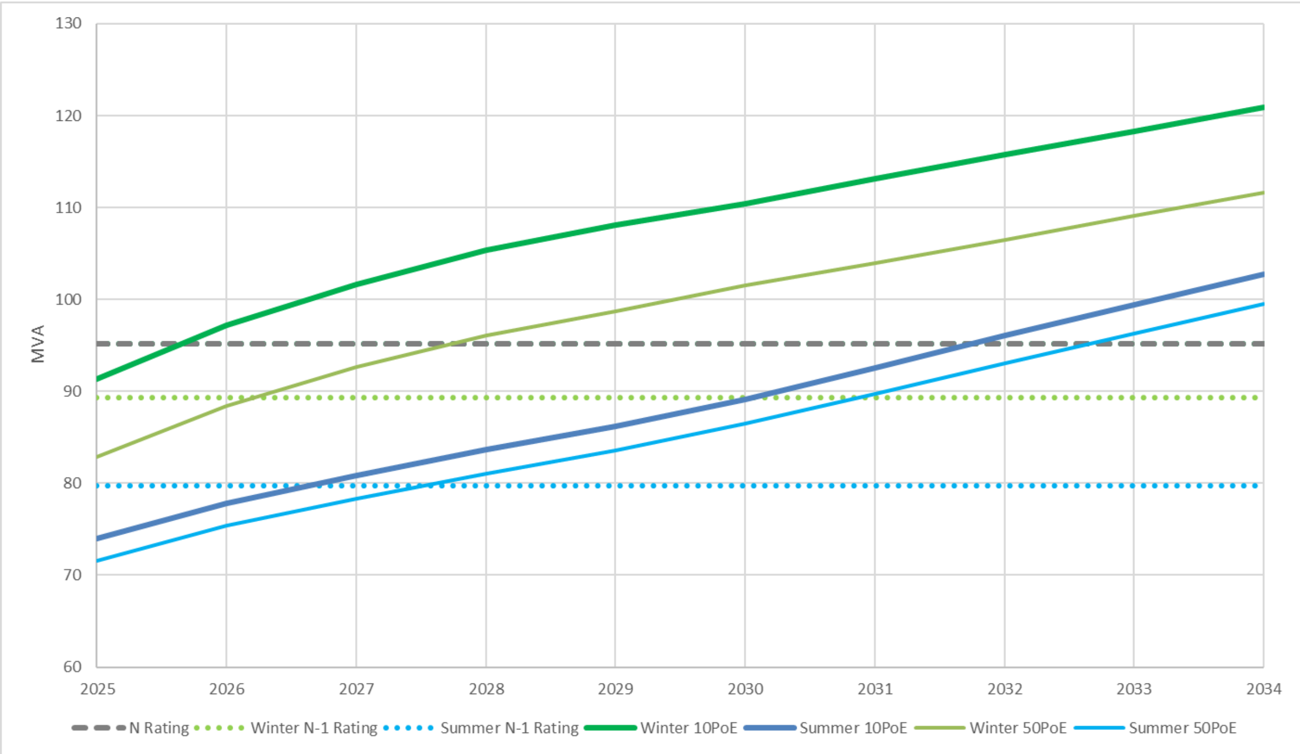
3.2.2 Maximum demand forecasts

The maximum demand forecasts for ST are shown in Figure 3–2. It is noted that maximum demand is forecast to increase rapidly over the next several years as a result of some significant customer connections subdivision developments occurring in the northern part of the Somerton supply area.

ST is a winter peaking zone substation. The ST maximum demand (prior to load transfers) is forecast to be 91.3 MVA for the winter of 2025 under a 10% Probability of Exceedance (**POE**). By 2034 it is forecast that maximum demand will rise to approximately 121 MVA.

[3] Victorian Planning Authority – The North Growth Corridor Plan.

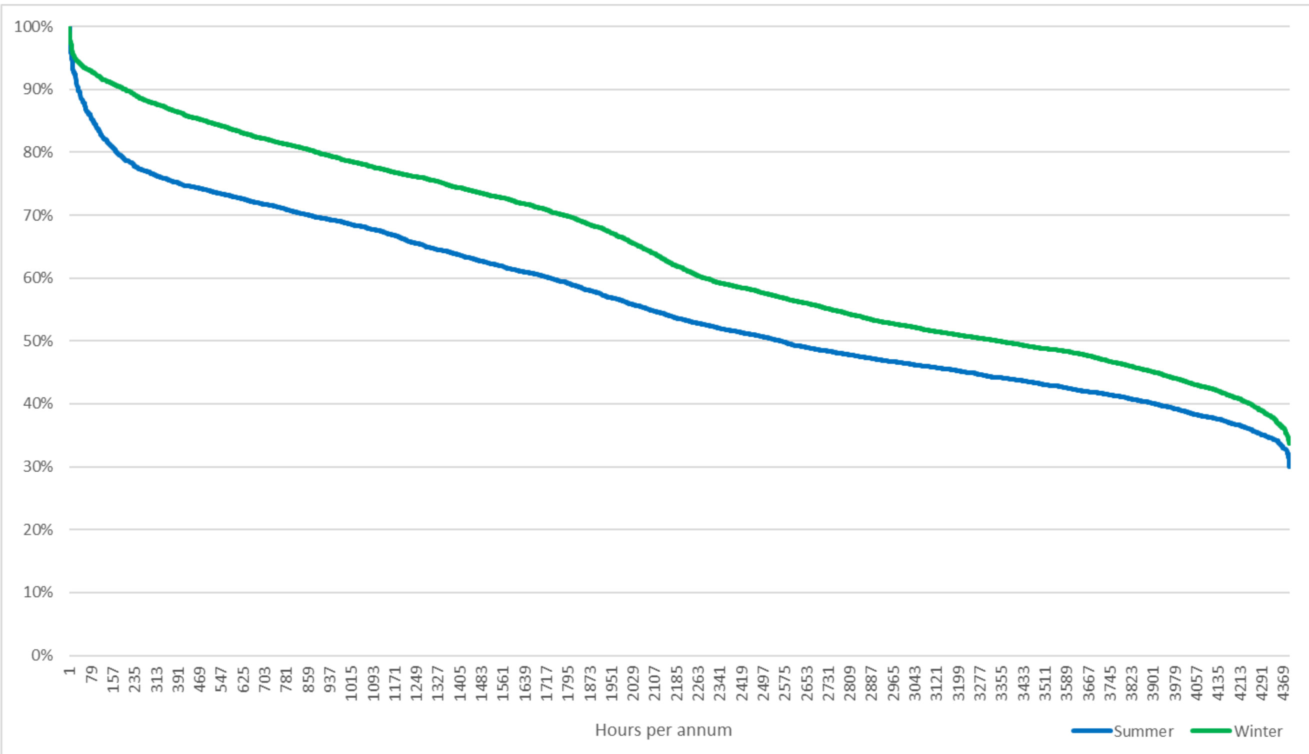
Figure 3–2: ST maximum demand forecast and ratings (MVA)



ST is expected to exceed its N rating by 2026 for a 10% PoE winter maximum demand, and 2028 for a 50% PoE winter maximum demand. The N rating is expected to be exceeded in summer from 2032. ST is already exceeding its N-1 rating for a 10% PoE winter maximum demand and is expected to exceed its N-1 rating by 2027 for a 50% PoE winter maximum demand and a 10% PoE summer maximum demand.

The duration of the demand experienced at ST is illustrated in Figure 3–3 with a summer load factor of 0.56 and a winter load factor of 0.64.

Figure 3–3: ST load-duration curve (% of summer and winter maximum demand)



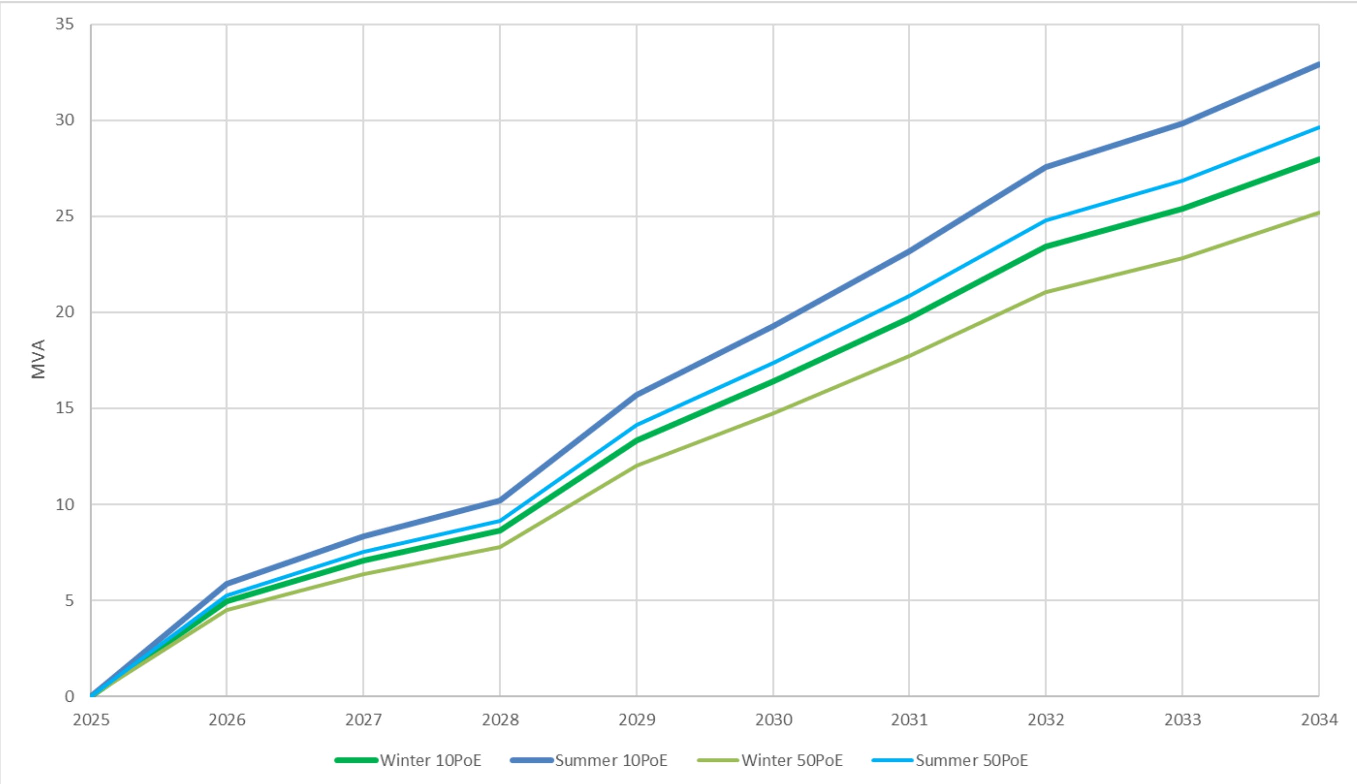
At ST, the share of the maximum demand from a total of 19,331 customers (forecast to be consuming up to 91.3 MVA of coincident net load in winter 2025 with 328 GWh of net annual energy consumption), comprises of:

- 16,756 residential customers consuming 35 MVA peak winter load (average 0.002 MVA per customer) and 21% of the annual energy consumption.
- 2,418 commercial customers consuming 24 MVA of peak winter load (average 0.01 MVA per customer) and 51% of the annual energy consumption
- 157 industrial customers consuming 32 MVA of peak winter load (average of 0.20 MVA per customer) and 28% of the annual energy consumption.

Currently there is no HV-connected embedded generation supplied from ST zone substation other than the small LV-connected residential and commercial solar PV. For ST, there are approximately 7,600 solar PV installations with a capacity of 38 MW, a penetration of 39% of customers.

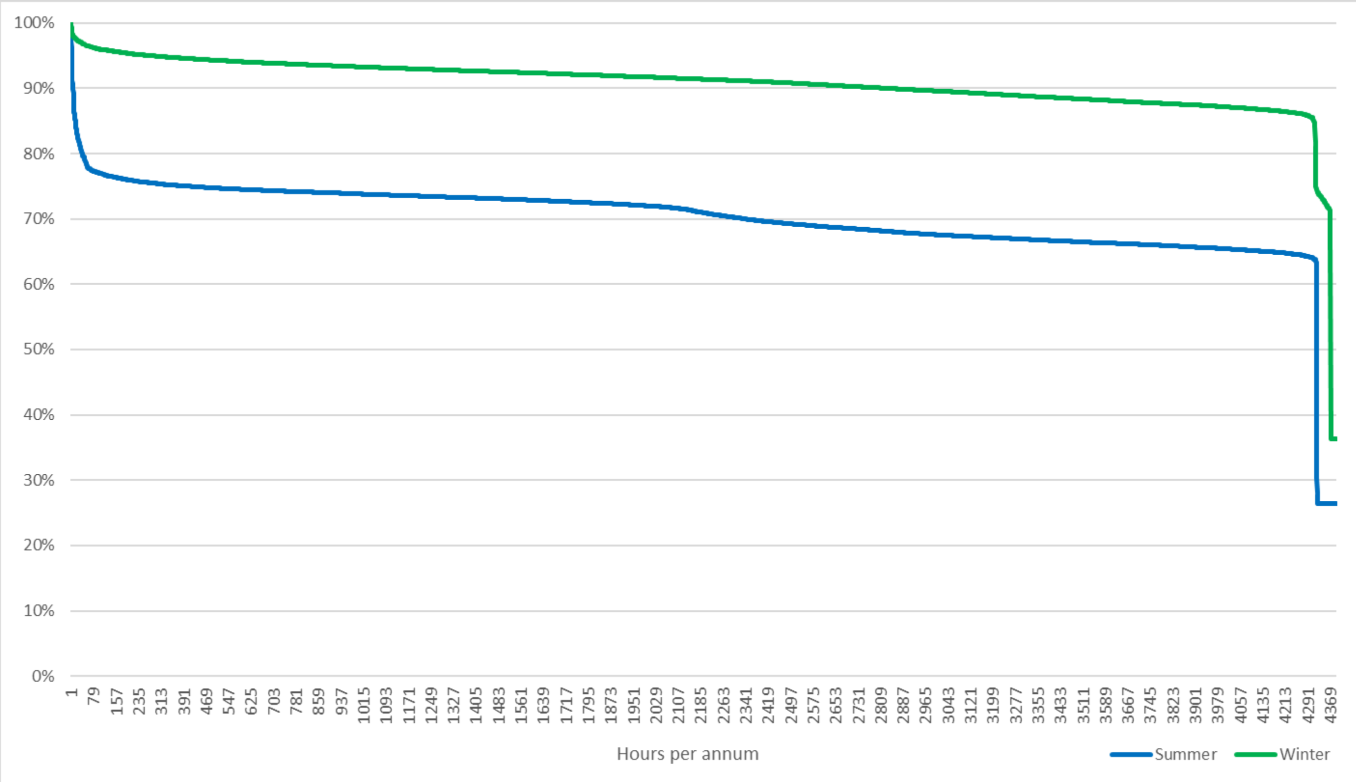
In addition to this forecast demand increase, there are new major customers expected to connect to the network within the northern part of Somerton supply area (within the next two to three years) that is expected to have a total maximum demand of 33 MVA (summer) / 28 MVA (winter) by 2034. This new load is planned to be connected at the 22kV level of the network. The maximum demand forecasts shown in Figure 3–4.

Figure 3–4: Major customer maximum demand forecast (MVA)



The duration of the demand experienced is illustrated in Figure 3–5 with a summer load factor of 0.70 and a winter load factor of 0.90.

Figure 3–5: Major customer load-duration curve (% of summer and winter maximum demand)



3.3 Credible solution requirements to address the identified need

There is forecast to be insufficient capacity to supply the forecast maximum demand at ST with the existing assets that are in place. This is likely to lead to a significant deterioration in supply reliability for customers within the Somerton supply area under system normal and single contingency conditions. This is exacerbated by the deteriorating transfer capacity away from ST zone substation to surrounding zone substations, via the 22 kV distribution feeder ties whose spare capacity is eroding with growth in maximum demand.

A credible solution to the identified need should seek to maintain levels of supply reliability for customers within the Somerton supply area. Hence, the solution should deliver sufficient capacity to reliably supply the demand within the supply area throughout the year, taking into account the forecast demand, available network capacity (under system normal and single contingency conditions) and load transfer capacity. The annualised cost of a credible option must be lower than the value of the EUE for which it is intending to displace. This could be achieved through a range of solutions, including one or a combination of a:

- Non-network or SAPS option;
- New 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with 6 new 22 kV feeders;
- New 66/22 kV 2 x 20/33 MVA Greenvale (GVE) zone substation with 5 new 22 kV feeders; and
- New 66/22 kV 2 x 45/75 MVA zone substation.

The minimum level of network support required for the underlying growth in customer maximum demand for the Somerton supply area is up to 30 MW over the 10-year period. Smaller (or staged) solutions of at least 4 MW (per annum), could provide sufficient capacity to address the identified need.

There is an additional level of network support required for the growth in maximum demand of major customers at (or in proximity to) their site in Craigieburn, being up to 33 MW over the 10-year period. Smaller (or staged) non-network or SAPS solutions of at least 3 MW (per annum), could provide sufficient capacity to address this part of the identified need.

4. Network options

JEN has identified two network options (in addition to the base case) that attempt to address the identified need:

- Option 1 - Base case "Do nothing", i.e., shed customer load when the network is overloaded;
- Option 2 - New 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with 6 new 22 kV feeders; and
- Option 3 - New 66/22 kV 2 x 20/33 MVA Greenvale (GVE) zone substation with 5 new 22 kV feeders.

Each network option includes the establishment of second 66/22 kV 2 x 45/75 MVA zone substation in Craigieburn, and an extension of the existing ST 66 kV sub-transmission network to connect in the proposed new zone substation to support growth from new major customers.

4.1 Option 1 - Do nothing (base case)

Option 1 involves maintaining the current operating regime. The capital cost of this option is assumed to be zero, with the cost of unplanned outages due to network asset overload represented by the value of EUE.

4.2 Option 2 - Craigieburn (CBN) development plan

Option 2 involves establishing a new 66/22 kV 2 x 20/33 MVA Craigieburn (CBN) zone substation with 6 new 22 kV feeders at a JEN-owned site 750 Hume Highway, Craigieburn and extending two 66 kV lines from ST to CBN along both sides of the Hume Highway (approximately 10 km in total).

It also includes the establishment of second 66/22 kV 2 x 45/75 MVA zone substation approximately 4km north of CBN for major customer connections and a further extension of the two 66 kV from CBN to connect in second zone substation (approximately 8 km in total).

This option is expected to deliver a substantially lower value of EUE compared to Option 1 as it is developed to address the identified need in its entirety.

The capital cost of Option 2 is approximately $72.58 million (real 2024) including:

- $9.34 million (real 2024) for 10 km extension of the 66 kV sub-transmission network to the future CBN zone substation (stage 1);
- $4.80 million (real 2024) for a further 8 km extension of the 66 kV sub-transmission network to the new customer zone substation (stage 1);
- $21.12(real 2024) for establishment of second zone substation (stage 1);
- $34.20 million (real 2024) for establishment of CBN (stage 2);
- $1.55 million (real 2014[4]) for the cost of CBN land procurement; and
- $1.57 million (real 2016[5]) for the cost of establishing CBN land services and access.

4.3 Option 3 - Greenvale (GVE) development plan

Option 3 involves establishing a new 66/22 kV 2 x 20/33 MVA Greenvale (GVE) zone substation with 5 new 22 kV feeders at a site yet to be procured in Yuroke or Greenvale, and extending two 66 kV lines from ST to GVE on separate routes (approximately 20 km in total).

[4] 1.30 multiple to real 2024 = $2.02 million

[5] 1.27 multiple to real 2024 = $2.00 million

It also includes the establishment of second 66/22 kV 2 x 45/75 MVA zone substation for major customer connections and an extension of two 66 kV lines from ST along both sides of the Hume Highway to connect in second zone substation.

This option is expected to deliver a substantially lower value of EUE compared to Option 1 as it is developed to address the identified need in its entirety.

The capital cost of Option 3 is approximately $105.9 million (real 2024) including:

- $21.12 million[6] 66/22 kV 2 x 45/75 MVA zone substation (stage 1);
- $14.14 million (real 2024) for 18 km extension of the 66 kV sub-transmission network to the zone substation (stage 1);
- $5.00 million (real 2024) for the costs of GVE land procurement, services and access (stage 1);
- $36.30 million (real 2024) for establishment of GVE (stage 2); and
- $29.34 million (real 2024) for 20 km extension of the 66 kV sub-transmission network to the new GVE zone substation (stage 2).

4.4 Potential deferred augmentation charge

Whilst both network options fully address the identified need, Option 2 has the lowest investment costs. Option 2 is the preferred network option with an in-service timing expected by 2027/28 with the connection for the new major customers provided in 2025/26.

Based on the total capital cost of Option 2 in section 4.2, a regulatory rate of return, and an annual operational costs, the deferral saving is approximately:

- $1.86 million[7] per annum (real 2024) for the CBN new zone substation and its feeders; and, if applicable
- $2.23 million[8] per annum (real 2024) for the second zone substation and sub-transmission line extension from ST.

This assumes the same reliability outcomes are maintained as with the preferred network option. This serves as a guide for non-network or SAPS providers to determine the financial viability of their proposal.

[6] This cost excludes customer contributions

[7] (34.20) x (4.43% + 1.00%) = $1.86 million.

[8] (26.27 + 9.34 + 4.80) x (4.43% + 1.00%) = $2.23 million.

5. Non-network and SAPS options

Potential non-network and SAPS options that could meet the investment objectives (as envisaged in the Application Guidelines Section 6.1) are listed below:

- **Demand Management** - Any measure or program targeted at reducing peak demand, including direct load control, broad-based demand management, or targeted customer demand response programs; and/or
- **Embedded Generation** - Increased local or distributed generation/supply options, including using capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity.

5.1 Non-network and SAPS options assessment scenarios

The aim in defining potential non-network and SAPS scenarios, is to test whether a non-network or SAPS option (or combination of options) is a viable way to avoid or reduce the scale of a network investment in a way that efficiently addresses the identified need. A non-network or SAPS option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g., generation plus demand management).

Potential non-network and SAPS scenarios for the Somerton supply area identified need are:

- **Scenario 1** - Meeting the identified need in part through a non-network option, mitigating the EUE risk only for the general load within the Somerton supply area 22 kV or LV distribution networks. The minimum level of non-network network support required for the underlying growth in customer maximum demand for the supply area is up to 30 MW over the 10-year period. Smaller (or staged) solutions of at least 4 MW (per annum cumulative), could provide sufficient capacity to address this part of the identified need. This assumes the network augmentation to connect the major customers' load proceeds to provide a complete option that addresses the identified need in its entirety; or
- **Scenario 2** - Meeting the identified need in its entirety through a non-network or SAPS option, mitigating the EUE risk for both the general load within the Somerton supply area 22 kV or LV distribution networks operating as a non-network solution (i.e. Scenario 1), and for the major customers' load by operating as a SAPS. The minimum level of non-network network support required for the underlying growth in customer maximum demand for the supply area is up to 30 MW over the 10-year period. Smaller (or staged) solutions of at least 4 MW (per annum cumulative), could provide sufficient capacity to address this part of the identified need. The additional level of SAPS required for the growth in maximum demand of the major customers at (or in proximity to) their site, being up to 33 MW over the 10-year period. Smaller (or staged) non-network or SAPS solutions of at least 3 MW (per annum cumulative), could provide sufficient capacity to address this part of the identified need.

No other scenarios have been identified.

5.1.1 Scenario 1 – Non-network or SAPS option to meet identified need in part

Viable generation, storage or load reduction options that can support any network capacity shortfalls in meeting the forecast demand of the general load within the Somerton supply area during the 10-year planning horizon, would require a level of support of up to 30 MW from an initial level of 4 MW could comprise of:

- 2 MW of generation initially, then 4 MW of generation per annum over 7 years; or
- 30 MW of generation initially.

Note, the maximum viable generator size per distribution feeder is no more than 15 MW, based on the ability of JEN's 22 kV network to connect the generation, and the need to provide a level of generation redundancy.

The support would be required for both system normal and for a single contingency on the following network assets which have identified network capacity limitations, for the periods of time when the demand exceeds the rating of the asset:

- ST No.1, No.2 or No.3 transformers; or
- COO No.2 transformer; or
- ST11, ST12, ST22, ST32, ST33 and KLO22 22 kV feeders.

Support for these assets would enable these assets to meet the forecast maximum demand in system normal and contingency situations.

The maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need, hence the generation would likely be a majority of new grid-connected systems. Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

The costs of this scenario could be comparable to the costs of the preferred network option detailed in Section 4.2 and could improve in competitiveness if value-stacked with market-based revenues. For example, the installed cost of small gas-fired generator is approximately $1.25 million (real 2024) per MW[9]. For 30 MW of generation, the cost will be over $37.5 million (real 2024), once land, operating and other establishment costs are included.

Based on the preliminary assessment above, a non-network option to support network capacity shortfalls in meeting the forecast demand of the general load within the Somerton supply area may be a credible option.

5.1.2 Scenario 2 – Non-network or SAPS option to meet identified need in its entirety

In addition to the support described above in section 5.1.1, this scenario also contemplates a SAPS solution to support the new major customers' connection within the Somerton supply area.

Viable generation and storage SAPS options that can reliably supply the forecast demand of the major customers' load in its entirety during the 10-year planning horizon, would require a level of support of up to 33 MW from an initial level of 6 MW could comprise of:

- 6 MW of generation initially, then 3 MW of generation per annum over 9 years; or
- 33 MW of generation initially.

The costs of this scenario could be comparable of the preferred network option. For example, the Engineer Procure and Construct (EPC) Capex cost of small gas-fired generator is approximately $1.25 million (real 2024) per MW[10]. For 33 MW of generation, the cost will be over $41 million (real 2024), once operating costs are included. However, this option coupled with on-site renewable generation sources could substantially reduce the operating costs of the overall non-network solution.

Based on the preliminary assessment above a SAPS option to supply the forecast demand of major customers' load in its entirety may be a credible option.

5.2 Non-network and SAPS options assessment criteria

This section reports on the credibility of potential non-network and SAPS options as alternatives or supplements for the preferred network option. The criteria used to assess the potential credibility was:

- **Addressing the identified need**: reducing or eliminating the supply reliability risk associated with the asset overloads.

[9] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

[10] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

- **Being technically feasible**: there are no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 5–1 shows the rating scale applied for assessing non-network options.

Table 5–1: Assessment criteria rating

Rating	Colour Coding
Does not meet the criterion	
Does not fully meet the criterion (or uncertain)	
Clearly meets the criterion	

The assessment has also considered whether a non-network or SAPS option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that meets the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Table 5–2 shows the initial assessment of non-network and SAPS options against the RIT-D criteria. The assessment identified some non-network or SAPS options to be potentially credible against RIT-D criteria (considered both in insolation, and in combination with network solutions). The assessment commentary for each of the generation, demand response and storage options are set out in the following sections.

Table 5–2: Assessment of non-network options against RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Economic	Timing
1.0 Generation and Storage				
1.1 Generation using gas turbines or diesel				
1.2 Generation using grid-scale solar and storage				
1.3 Standby generation (existing large customer)				
1.4 Storage only using grid-scale batteries				
2.0 Demand Management				
2.1 Customer power factor correction				
2.2 Customer solar power and storage systems				
2.3 Broad-based demand response				
2.4 Targeted demand response				

5.3 Non-network and SAPS options assessment commentary

5.3.1 Generation and storage

The assessment rationale for each of the generation and storage options is as follows, with their potential ability to meet the assessment criteria:

- **Generation using gas turbines or diesel (1.1):**

Identified need (met) - Capable of meeting identified need through provision of multiple gas turbine or diesel generators.

Technical (met) - Significant constraints and barriers to deployment of multi-megawatt generation equipment in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land and industrial areas that could form suitable sites for generation. There appears to be a high-pressure gas pipeline in the locality to the east of the Hume Highway as a potential fuel source.

Economic (met) - Costs of this type of generation appear comparable to the network alternatives excluding land, grid connection and operating costs. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated (and other services) through the market. The scale of estimated costs and the potential revenue streams illustrate the potential for an economically viable non-network and/or SAPS solution.

Timing (met) - Planning processes and the nature of the investment with likely noise and environmental objections, together with design requirements (both for the generators, gas connections and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

Overall – Generation using gas turbines or diesel (or other similar technology) is a potentially credible option.

- **Generation using grid-scale solar and storage (1.2):**

Identified need (partially met) - Capable of meeting identified need partially through provision of solar farms and/or additional rooftop solar, coupled with grid-connected batteries.

Technical (partially met) - Significant constraints and barriers to deployment of multi-megawatt generation equipment in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land and industrial areas (warehouse roof-space) that could form suitable sites for generation and storage. Energy and reliability requirements may be difficult to meet using solar generation alone without oversizing the batteries.

Economic (met) - Costs of this type of generation appear comparable to the network alternatives excluding land, grid connection and operating costs. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated/stored (and other services) through the market. The scale of estimated costs and the potential revenue streams illustrate the potential for a economically viable non-network and/or SAPS solution.

Timing (met) - Planning processes for zoning, together with design requirements (both for the generation and storage and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

Overall – Generation using grid connected solar and battery storage (or other similar technology) is a potentially credible option.

- **Standby generation (large customer) (1.3)**

Identified need (partially met) - As noted in section 3.2.2, there are large numbers of industrial and commercial customers consuming relatively large proportions of ST's maximum demand and annual energy in aggregate. It is likely that a number of those customers may be prepared to install or use their currently existing standby generation to operate disconnected from the grid in the event of a network limitation. The new major customers may also be open to negotiations at their own site.

Technical (partially met) - This type of standby generation model may be technically feasible depending on customer interest to install standby generation, or to utilise their existing standby generation. To meet the need, the solution would need to be operated as an aggregated portfolio.

Economic (partially met) - The economic viability of this model is dependent on the customer uptake and the load of those customers wishing to participate. Smaller load customers will require more installations for the same delivered response. Given ST currently has fault level limitations, it is unlikely to be able to operate large amounts of non-inverter based generation synchronised and exporting to the network. Hence the size of the customer standby generation is limited to the customer's maximum demand.

Timing (met) – Customer recruitment and installation of standby generation could be a multi-year process but may be completed within the timeframe of the preferred network option.

Overall – Standby generation at customer premises is a potentially credible option.

- **Storage only using grid-scale batteries (1.4)**

Identified need (partially met) - Capable of meeting identified need through provision of grid-connected batteries.

Technical (partially met) - Significant constraints and barriers to deployment of multi-megawatt batteries in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land that could form suitable sites for storage. Energy requirements may be difficult to meet using storage alone without oversizing the batteries.

Economic (partially met) - Costs of this type of solution using only batteries is likely to be more expensive than the network alternatives excluding land, grid connection and operating costs. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated/stored (and other services) through the market. However, the scale of estimated costs and the potential revenue streams illustrate the potential for a economically viable non-network and/or SAPS solution is not as strong as a solution coupled with generation.

Timing (met) - Planning processes for zoning, together with design requirements (for storage and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

Overall – Generation using grid connected battery storage (or other similar technology) is a potentially credible option.

5.3.2 Demand management

The assessment rationale for the demand management/efficiency options is as follows, with their potential ability to meet the assessment criteria:

- **Customer power factor correction (2.1)**

Identified need (not met) - This option cannot address the identified need because ST operates close to unity power factor, even at maximum demand. Therefore, further reactive power compensation will provide no reductions in demand.

Technical (met) - This type of solution is technically feasible for industrial users on a certain type of contract and is achievable.

Economic (met) - This solution could be cost-effective on parts of the network with low power factor.

Timing (met) - This option could be completed within the timeframe of the preferred network option.

Overall – Power factor correction is not a potentially credible option, as the power factor is already fully corrected for the supply area.

- **Customer solar power and storage systems (2.2)**

Identified need (partially met) - As noted in section 3.2.2, solar PV customer premises penetration is not fully saturated in the Somerton supply area and there is potentially opportunity to install a lot more solar PV on residential, commercial and industrial properties. The major issue to be address is to couple storage with the solar PV to balance the supply to the shortfall in capacity for the demand. Storage behind the meter uptake is currently very low, however opportunities are potentially going to emerge with the use of electric vehicle storage to provide network support.

Technical (met) - This option is technically feasible as the appetite for customers to take up solar PV is high and the opportunity for customers to take up electric vehicles and behind the meter storage is emerging with aggregator functions starting to develop in the market.

Economic (met) - Achieving a greater than average solar PV and storage take up with some level of control for network support would require a financial incentive.

Timing (met) - This option could be completed within the timeframe of the preferred network option.

Overall - Customer solar power and storage systems is a potentially credible option to be used for network support purposes in aggregate.

- **Broad-based demand response (2.3)**

Identified need (partially met) – To implement a broad-based demand response program across the supply area, each of JEN's customers would need to be approached to participated in a managed program to reduce consumption. There are a relatively large number of commercial and industrial customers in the supply area that could be well equipped to provide such a service to reduce their demand, and the demand response could be expanded to cover residential demand to allow some level of control over air-conditioning demand at times of peak, both using financial incentives program.

Technical (partially met) - This option may be technically feasible but could struggle to meet the demand reduction needs in the later part of the forecast period given a high participation rate would be needed. Instead, it is probably more feasible for this option to be able to defer implementation of the network option in the initial years.

Economic (partially met) - It is unclear whether this option is economically feasible, as it will depend on the customers willingness to participate and the size of the incentives needed to active the demand reductions needed. Nevertheless, there have been examples where broad-based demand response programs have proved to be possible.

Timing (met) - This option could be completed within the timeframe of the preferred network option.

Overall – Broad based demand response is a potentially credible option, particularly in the initial years of the 10-year period.

- **Targeted demand response (2.4)**

Identified need (partially met) – To implement a targeted demand response program across the network constrained assets only, each of JEN's customers in these specific areas would need to be approached to participated in a managed program to reduce consumption. There are a relatively large number of commercial and industrial customers in the supply area that could be well equipped to provide such a service to reduce their demand, and the demand response could be expanded to cover residential demand on those capacity constrained feeders only to allow some level of control over air-conditioning demand at times of peak, both using financial incentives program.

Technical (partially met) - This option may be technically feasible but could struggle to meet the demand reduction needs in the later part of the forecast period given a high participation rate would be needed. Instead, it is probably more feasible for this option to be able to defer implementation of the network option in the initial years.

Economic (met) – It is more likely this option will be economically feasible as the demand response is targeted to those areas of the supply area that have a network limitation. Success of the program will depend on the customers willingness to participate, and the size of the incentives needed to active the demand reductions needed. Nevertheless, there have been examples where targeted demand response programs have proved to be possible.

Timing (met) - This option could be completed within the timeframe of the preferred network option.

Overall – Targeted demand response is a potentially credible option, particularly in the initial years of the 10-year period.

6. Conclusion and next steps

6.1 Conclusion

The analysis outlined in section 5 indicates the potential for non-network or SAPS solutions, or combinations of non-network and network options, that are likely to adequately meet the criteria given in this report.

This options screening report has demonstrated it is possible that a non-network or SAPS solution could be technically and economically feasible to address the identified need for the Somerton supply area.

6.2 Next steps

We are interested in exploring all potential non-network solutions with proponents. We recognise that some proponents may require information in addition to that provided in this report. If you do need further information, please contact us as early as possible, to ensure that sufficient time is available to fully assess feasible network and non-network potential solutions. It should be noted that parts of the network exhibit volatile load growth, usually driven by economic and demographic factors that are difficult to foresee and model. It is essential that alternatives to network solutions are presented by proponents in sufficient time to allow for their thorough evaluation, planning and implementation.

We now invite written submissions on this options screening report from registered participants, AEMO and interested parties, including pricing proposals from prospective non-network and SAPS providers detailing alternative solutions and demonstrating how the solutions achieve the assessment criteria presented in this report. All pricing proposals should include sufficient technical and financial information to enable JEN to undertake a comparative analysis of the proposed solutions against alternative options.

A period of three months shall be made available for preparation of submissions and proposals. At the end of this period, JEN will assess all options we consider to be credible against the network options. All submissions, and enquiries must be identified as “Somerton Supply Area RIT-D” and should be directed to: PlanningRequest@jemena.com.au

Submissions must be lodged with us on or before 15 November 2024.

All submissions will be published on JEN’s website. If you do not wish to have your submission published, please indicate this clearly in your submission.

As the total cost of the most expensive credible network option to address the identified need is greater than the trigger threshold of $12 million[11] for the publication of and consultation on a Draft Project Assessment Report (DPAR), we intend to prepare and publish a DPAR. The DPAR will present a detailed assessment of all credible network, non-network and SAPS options that address the identified need, applying the latest available information on demand forecasts, VCR estimates and project cost estimates. The DPAR will identify the proposed preferred option. Further consultation, in accordance with the RIT-D process set out in the Rules, will then proceed.

[11] Source: AER 2021 RIT and APR cost thresholds review (November 2021).

7. Appendix A – Checklist of compliance clauses

Table 7–1 presents a checklist of the NER clause 5.17.4(e) and references the section within this options screening report where those clauses are addressed.

Table 7–1: Compliance clauses checklist

Clause	Section
(1) a description of the identified need;	3.1
(2) the assumptions used in identifying the identified need;	3.2
(3) if available, the relevant annual deferred augmentation charge associated with the identified need;	4.4
(4) the technical characteristics of the identified need that a non-network option or (in relation to a SAPS enabled network) a SAPS option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; (iii) contribution to power system security or reliability; (iv) contribution to power system fault levels as determined under clause 4.6.1; and (v) the operating profile;	3.3
(5) a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options, non-network options and (in relation to a SAPS enabled network) SAPS options;	4 & 5
(6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on: (i) a technical definition or characteristics of the option; (ii) the estimated construction timetable and commissioning date (where relevant); and (iii) the total indicative cost (including capital and operating costs);	4 & 5
(7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a proposal for consideration by the RIT-D proponent.	6

