Jemena Electricity Networks (Vic) Ltd

Fairfield Zone Substation (FF) Transformer No.3 Condition and 4th Bus

RIT-D Stage 1: Options Screening Report Notice of Determination under clause 5.17.4(c) of the National Electricity Rules

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Fairfield Zone Substation (FF) Transformer No.3 Condition and 4th Bus

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Name	Job Title	Date	Signature
Reviewed by:			
Theodora Karastergiou	Future Network & Planning Manager	16/07/2023	Email endorsed
Approved by:			
Karl Edwards	General Manager Asset & Operations	08/08/2023	Email endorsed

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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 the lowest possible cost. To do this, we must choose the most efficient solution to address current and emerging network limitations. This means choosing the solution that maximises the present value of net economic benefits to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**).

Identified Need

Fairfield zone substation (**FF**) is owned and operated by Jemena, providing power to approximately 6,756 Jemena customers and 3,664 CitiPower customers in Melbourne's inner northeast, in Fairfield and Alphington within the JEN supply area, and parts of Thornbury within the CitiPower supply area.

The condition of the No.3 transformer, which is one of the three 22/6.6kV transformers at FF, is deteriorating and at risk of failure, which poses both a safety and a reliability risk. Moreover, the transformer is now located in a position of the switchyard that inhibits further expansion of the zone substation. Jemena has assessed that this transformer has reached the end of its engineering life, and allowing this transformer to remain in-situ poses an unacceptable risk to safety of workers and public, and to the reliability of electricity supply to Jemena's customers within the supply area.

Approach to screening options

Jemena has developed a set of potential network solutions aimed at addressing the identified need. Jemena has also investigated whether viable non-network or stand-alone power system (**SAPS**) solutions exist, in which case Jemena 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, if 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), Jemena 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 FF meeting its forecast demand during the 10-year planning horizon without the No.3 transformer and a fourth bus being available (a level of support of up to 14 MW). This would allow the No.3 transformer to be retired completely and removed from the site. Alternatively, smaller non-network or SAPS solutions of at least 6 MW could provide sufficient capacity to defer the preferred network option.

Summary of findings

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

- **Addressing the identified need**: reducing or eliminating the safety, environmental and 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.
- **Commercially 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 Jemena has applied for assessing the 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 the RIT-D criteria

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

Based on these results, Jemena has concluded that none of the potential non-network or SAPS options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network or SAPS options adequately address the identified need.

Hence, under NER clauses 5.17.4(c) and 5.17.4(d), Jemena has published this Notice of Determination to notify that the publication of an options screening report is not required for this identified need. The remainder of this report provides the evidence underpinning this Notice of Determination that non-network options or SAPS options do not provide potential credible options for addressing the identified need in this instance.

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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 northwest 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 facilitates 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.

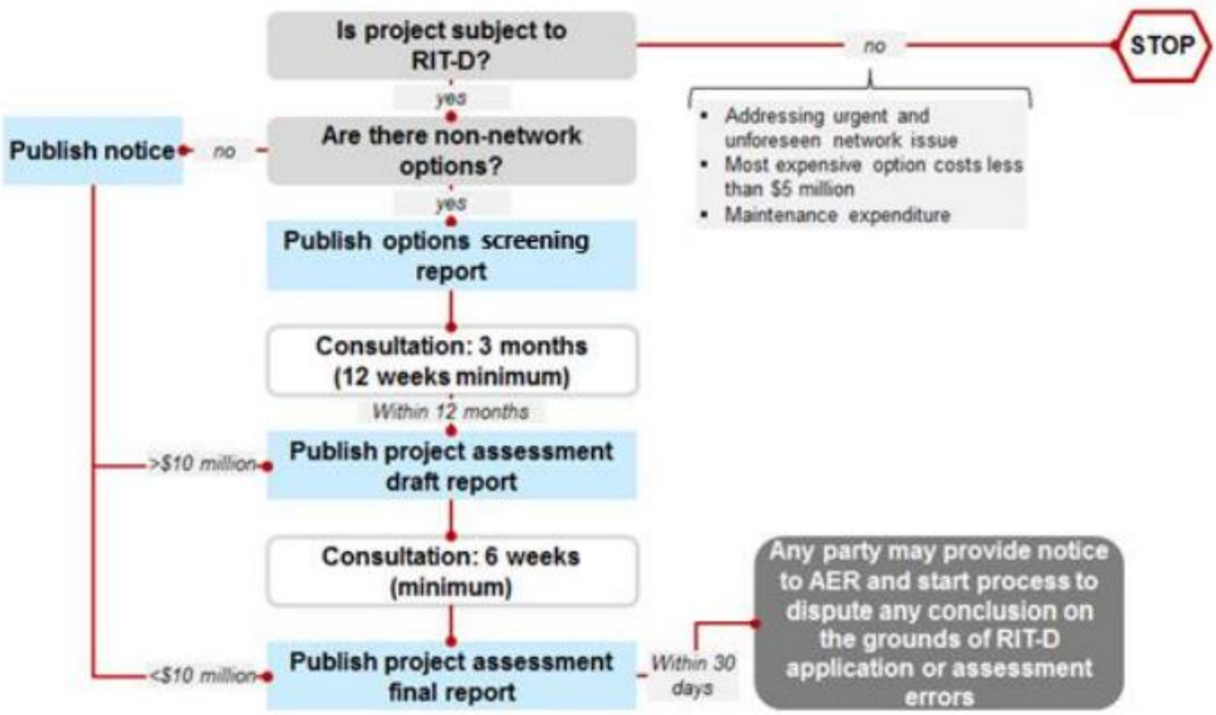
Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CB	Circuit Breaker
CBRM	Condition-Based Risk Management
CP	CitiPower
DM	Demand Management
DPAR	Draft Project Assessment Report
EG	Embedded Generation
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere
MW	Mega Watt
MWh	Megawatt hour
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
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 that best address an identified need on the electricity distribution network. The RIT-D applies in circumstances where a network limitation (an "identified need") exists 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 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
- a significant part of one or more potential credible options to address the identified need.

This report:

- summarises the non-network and SAPS screening requirements and the assessment approach (Section 2)
- describes the identified need the project is aiming to address (Section 3)
- describes the network options tested to date (Section 4)
- assesses the potential of non-network and/or SAPS options to help address the identified need (Section 5); and
- states the conclusion reached on the credibility of potential non-network and SAPS options (Section 6).

1 AER 2021 RIT and APR cost thresholds review (November 2021).

2 AER Application Guidelines RIT-D (August 2022).

2. Screening Requirements and approach

This section:

- defines the option screening requirements as set out in the:
  - AER RIT-D Application guidelines (Application Guidelines), August 2022; and
  - National Electricity Rules (NER), Version 200, 30 May 2023.
- describes the approach to assessing the credibility of non-network 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) commercially 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.

Jemena has interpreted the guidance to mean that a credible option could consist of a non-network component and a network component that, when combined, meets 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

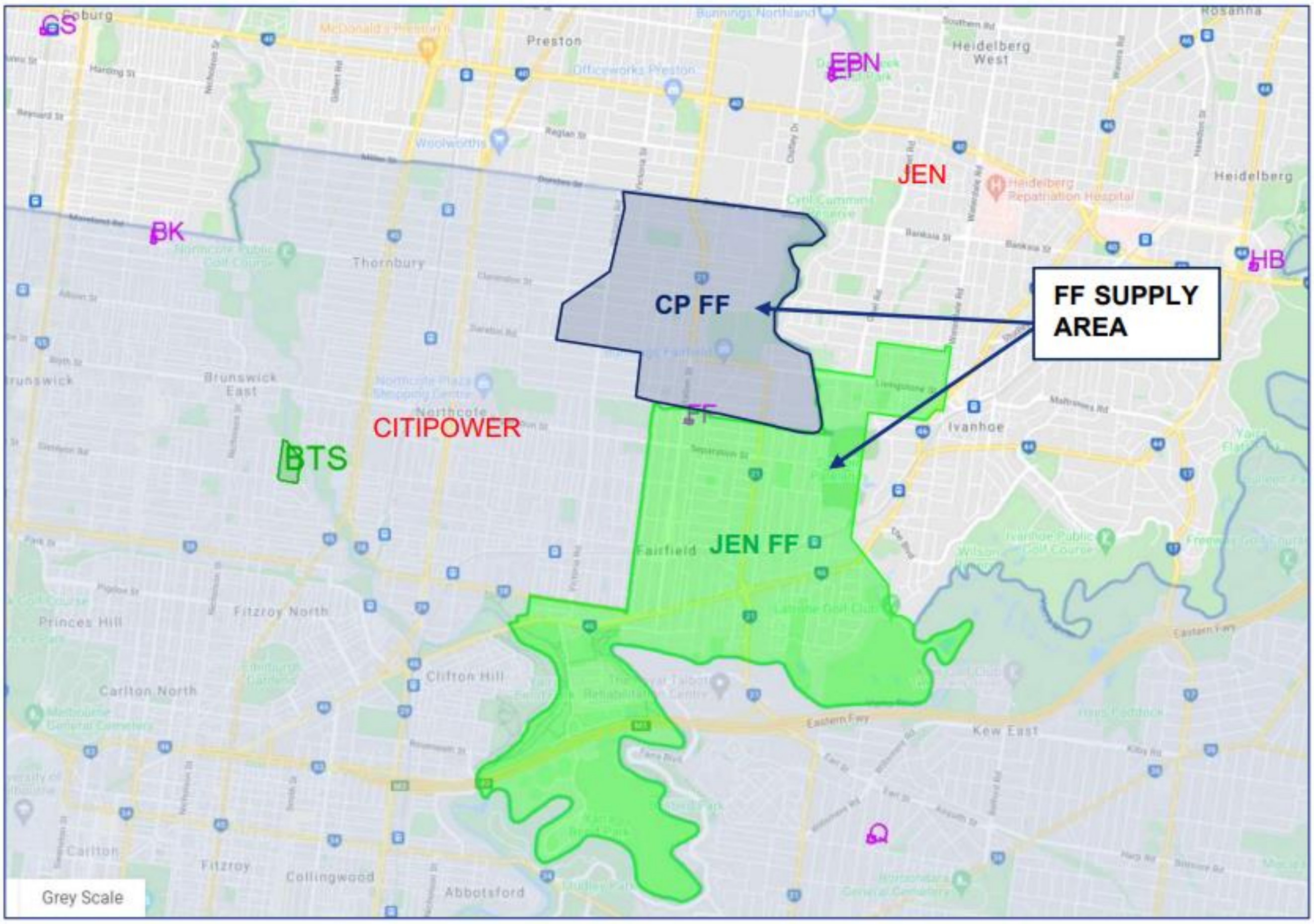
JEN’s approach to assessing the credibility of potential non-network and SAPS options includes:

- Describing the identified need, including the condition issues driving the proposed investment and the capacity, demand and 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 full 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 potentially credible non-network or SAPS options, identifying any issues that require further examination.

3. Identified need and project objectives

Jemena has prepared this report to assess whether the reliability and safety needs of the Fairfield zone substation (**FF**) could be realised either fully, or in part through non-network or SAPS options. FF is owned and operated by Jemena, providing power to approximately 6,756 Jemena customers and 3,664 CitiPower customers (predominantly residential) in Fairfield and Alphington within the JEN supply area, and parts of Thornbury within the CitiPower supply area, in Melbourne's inner northeast, through a network of 6.6kV feeders. Figure 3–1 shows the geographic supply area of FF and its surroundings, including the geographic split between JEN and CitiPower service areas.

Figure 3–1: Supply areas of Fairfield (FF) Zone Substation - JEN and CitiPower



To assess whether a non-network or SAPS option could be beneficial, it is important to first define the identified need for this location. Jemena has identified FF as a priority for investment based on two key needs:

- Firstly, the need to protect power sector workers and members of the public from harm caused by equipment failure or deteriorating asset condition (Safety); and,
- Secondly, the need to continue to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (Reliability).

3.1 Safety

The ability to provide a safe network in the FF supply area is being compromised by the poor and deteriorating condition of the FF No.3 transformer. This poses a health and safety risk due to the possibility of asset failure and noise issues.

3.1.1 Condition of network assets

This investment need is driven by the poor condition of the 22/6.6kV 10/13.5MVA No.3 English-Electric power transformer at FF, which was installed in 1955 and is at risk of failure, posing a safety risk. This transformer is more than 68 years old, one of the oldest on the JEN network, and is showing signs of accelerating deterioration and is at the end of its engineering end-of-life.

Jemena's Condition Based Risk Management (**CBRM**) asset management process defines a Health-Index for each asset. The Health-Index is categorised as follows.

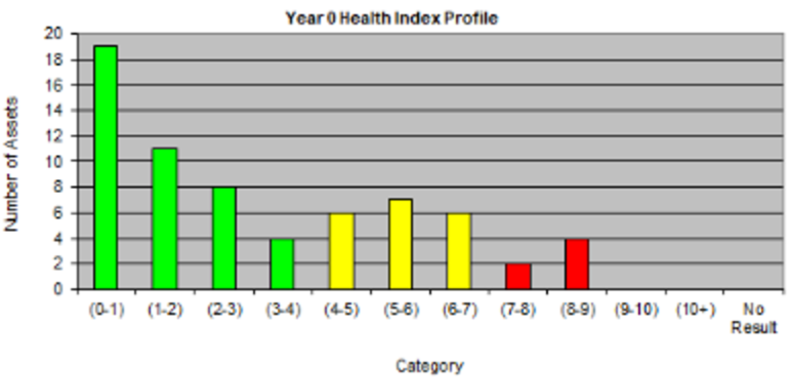
Figure 3–2: Heath-Index Meaning[3]

Condition	Health Index	Remnant Life	Probability of Failure
Bad	10	At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good	0	>20 years	Very low

Health-Index values over 7 represent serious deterioration; i.e. advanced degradation processes now reaching the point that they threaten failure and the rate of further degradation will be relatively rapid.

The condition of the FF No.3 transformer is assessed as having a Health-Index of 8.95 on a scale of 0-10 and is therefore one of the four worst condition transformers on the JEN network out of a total population of 67 power transformers.

Figure 3–3: Heath-Index of JEN's Population of Power Transformers



The FF No.3 transformer has a moisture content of 31 ppm and a paper insulation DP of 250, both considered to be poor. The transformer also has a confirmed noise issue with a significant margin of up to 22dB(A) and is not compliant with EPA requirements.

The potential health and safety risks associated with this poor condition transformer include i) Jemena's personnel within the zone substation being exposed to possible transformer failure, ii) the public living and working in the vicinity of the zone substation from excessive noise levels, and iii) to the public more broadly from power supply interruptions.

3 Source: Jemena's Electricity Primary Plant Asset Class Strategy (Document No. ELE-999-PA-IN-008).

3.1.2 Credible solution requirements to address the safety need

Credible solutions are required to deliver a service that would allow Jemena to decommission, remove and dispose of the existing FF No.3 transformer to maintain safety for Jemena's personnel and the general public.

3.2 Reliability

The No.3 transformer at FF has been taken off load due to its excessive noise levels breaching Environmental Protection Agency (**EPA**) noise limits and is only put on load when another transformer at FF is taken out of service, either for either maintenance or a forced outage.

Furthermore, there is a current need to extend the 6.6kV buses at FF to accommodate feeders for additional customer load. However, the location of this existing poor-condition transformer is impeding this expansion of the zone substation to support the requirements of new customers connecting to the FF supply area.

Jemena's planning standard for its zone substation reliability 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 by a Value of Customer Reliability (**VCR**) ($/MWh). Jemena uses this approach to identify, quantify and prioritise investment in the distribution network.

Typically, the EUE is calculated by understanding the load-at-risk for each zone substation. This is normally calculated through modelling load-at-risk under system normal and whether 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, presented below for FF in Sections 3.2.1 and 3.2.2.

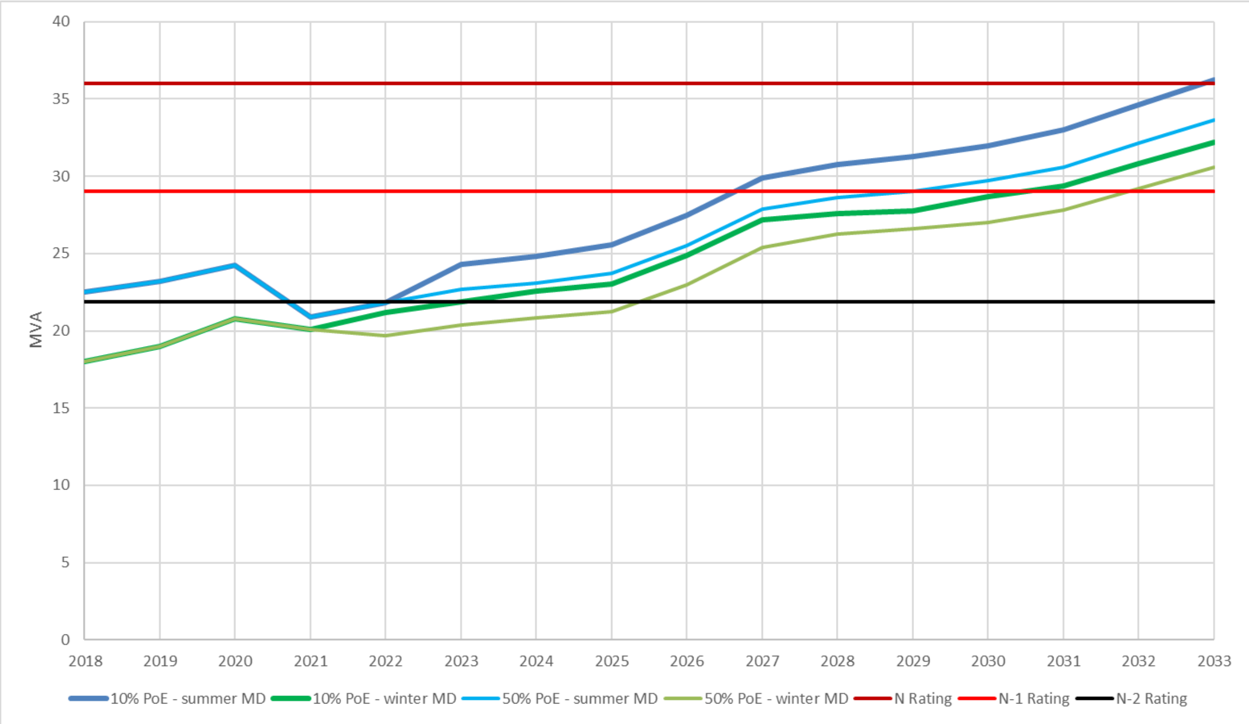
3.2.1 Maximum demand forecasts

The maximum demand forecasts for FF are shown in Figure 3–4. Maximum demand is forecast to increase rapidly over the next several years due to significant customer connections occurring in the southern part of the FF supply area. The FF maximum demand is forecast to be 24.8 MVA for the summer of 2024 under a 10% Probability of Exceedance (**POE**). By 2033, it is forecast that the maximum demand will be approximately 36.3 MVA. The highest maximum demand over the 10-year planning horizon is forecast to be 36.3 MVA for the summer of 2033.

At FF, the share of the maximum demand from a total of 10,420 customers (forecast to be consuming up to 25 MVA of coincident net load in summer 2024 with 80 GWh of annual energy consumption), comprises of:

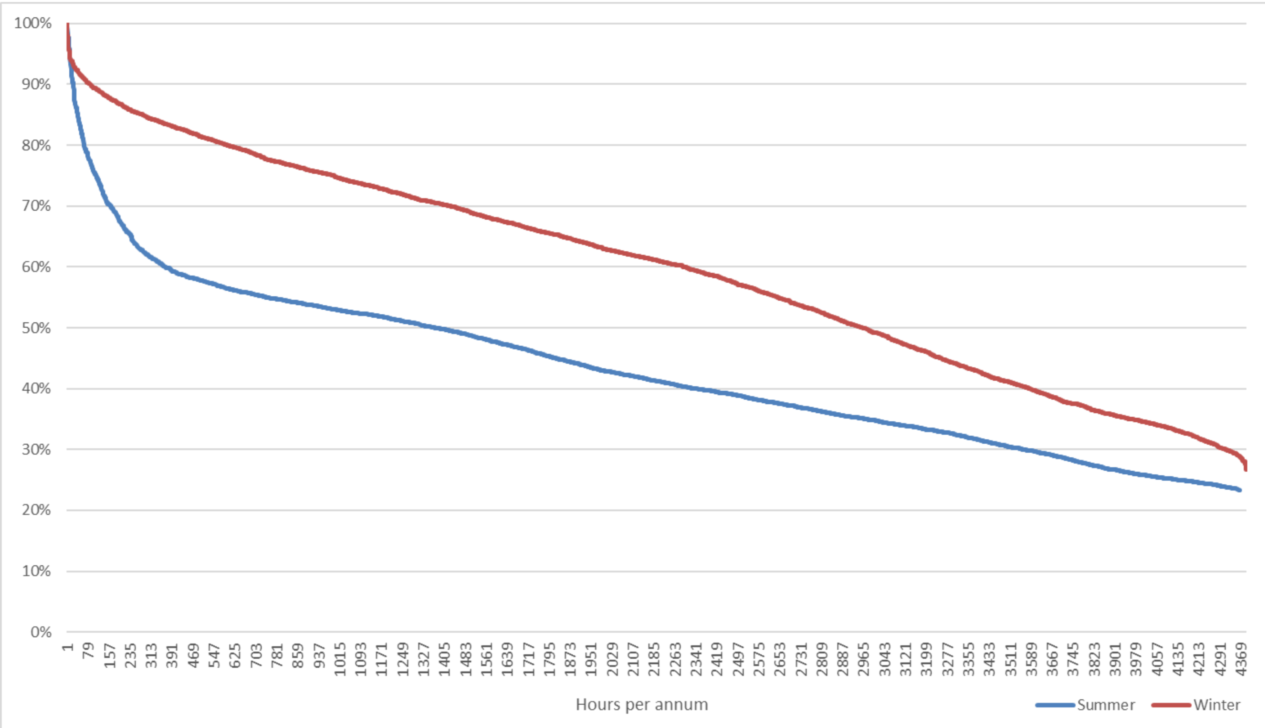
- 9,632 residential customers consuming 14 MVA peak summer load (average 0.0015 MVA per customer) and 53% of the annual energy consumption
- 776 commercial customers consuming 8 MVA of peak summer load (average 0.01 MVA per customer) and 42% of the annual energy consumption
- 12 industrial customers consuming 3 MVA of peak summer load (average of 0.25 MVA per customer) and 5% of the annual energy consumption.

Figure 3–4: FF maximum demand forecast and ratings (MVA)



The duration of the demand experienced at FF is illustrated in Figure 3–5.

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



Currently, there is no HV-connected embedded generation supplied from the FF zone substation other than the small LV-connected residential and commercial solar PV. For FF, there are approximately 1,260 solar PV installations[4] with a capacity of 5 MW, a penetration of 12% of customers.

4 935 in the JEN supply area totalling 3.5 MW, and 324 in the CitiPower supply area totalling 1.3 MW.

3.2.2 Network capacity

The zone substation assets limiting the summer and winter capacity at FF are the 22/6.6 kV power transformers' thermal limits, and the existing 6.6 kV buses to support additional feeders to meet increasing demand within the FF supply area. Over the 10-year planning horizon, these limits apply under single contingency conditions only.

FF consists of three 22kV/6.6kV power transformers, and 14 x 22kV feeders from three 6.6kV indoor bus switchboards. The ratings of the key assets are:

- three transformers rated at 18 MVA (No.1), 18 MVA (No.2) and 13.5 MVA (No.3 on standby) continuous, with cyclic ratings of 21.9 MVA (No.1), 21.9 MVA (No.2) and 14.5 MVA (No.3 on standby);
- three 6.6kV buses each rated at 2,500 Amps.

The total N nameplate rating of the zone substation is 36.0 MVA. The N-1 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service, and the No.3 transformer is brought back on load. This gives an N-1 rating of 29.0 MVA.

Given the poor, end-of-life condition of the No.3 transformer, there is a chance it cannot be returned to service to carry load, and therefore the N-2 rating is based on the transformer cyclic ratings, assuming the No.1 or No.2 transformer is out of service, and the No.3 transformer is out of service. This gives an N-2 rating of 21.9 MVA.

The load transfer capacity away from FF is 0 MVA. This is because it operates as a 6.6kV island, surrounded by distribution networks operating at different voltage levels. This makes FF highly susceptible to long-duration outages for transformer and bus faults under high-loading conditions.

3.2.3 Credible solution requirements to address the reliability need

There is presently sufficient capacity to supply the forecast maximum demand at FF with the existing assets. However, with the poor condition of the No.3 transformer and the lack of spare 6.6kV feeder bays (on existing 6.6kV buses), there is a significant deteriorating supply reliability risk under contingency conditions from either another transformer failure or a bus failure. This is because FF zone substation does not have any distribution feeder tie transfer capacity to surrounding zone substations, as it operates as a 6.6kV island surrounded by distribution networks operating at different voltage levels. Failure of an FF bus or transformer means load could only be transferred to the other buses or transformers at FF, severely limiting the transfer options to restore supply when compared to other zone substations in the network.

A credible option should seek to maintain levels of supply reliability. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply the load under N-1 network conditions, in which the cost of EUE exceeds the annualised cost of the investment. This could be achieved through a range of solutions, including:

- meeting the identified need in its entirety through a non-network or SAPS option
- replacing the No.3 22/6.6kV transformer with a new transformer located in a different area of the switchyard to accommodate a 4th 6.6kV bus with new 6.6kV feeder bays
- removing the No.3 22/6.6kV transformer from the site to accommodate a 4th 6.6kV bus with new 6.6kV feeder bays, supporting the transformation capacity with a non-network or SAPS option
- replacing the No.3 22/6.6kV transformer with a new transformer and utilising existing 6.6kV feeder bays by piggybacking cables, supporting the bus capacity with a non-network or SAPS option.

A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon without the No.3 transformer or the fourth bus being available (a level of support of up to 14 MW). This would allow the existing No.3 transformer to be retired completely and removed from the site. Smaller non-network or SAPS solutions of at least 6 MW could provide sufficient capacity to defer the preferred network option.

4. Network options

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

- Option 1 – Base case "Do Nothing", i.e., run assets to failure;
- Option 2 – Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF;
- Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF; and
- Option 4 - Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables.

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 asset failure represented by the value of EUE.

4.2 Option 2 - Replace No.3 22/6.6kV transformer and install 4th 6.6kV bus at FF

Option 2 involves replacing the No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer located in a different area of the switchyard and installing a fourth 6.6kV bus with new 6.6 kV feeder bays, with the cost of unplanned asset failure represented by a lower value of EUE compared to Option 1.

The capital cost of Option 2 is approximately $13.64M ($2023 real).

4.3 Option 3 - Retire No.3 22/6.6kV transformer and install 4th 6.6kV bus at FF

Option 3 involves retiring the No.3 22/6.6 kV transformer and removing it from the site (without replacing it) to accommodate a fourth 6.6 kV bus with new 6.6 kV feeder bays, with the cost of unplanned asset failure represented by a lower value of EUE compared to Option 1.

The capital cost of Option 3 is approximately $6.95M ($2023 real).

4.4 Option 4 - Replace No.3 22/6.6kV transformer, using existing 6.6kV buses to piggyback cables

Option 4 involves replacing the No.3 22/6.6 kV transformer with a new 22/6.6 kV 18 MVA transformer and utilising the existing 6.6kV feeder bays by piggybacking any new feeder cables that will be needed to support customer demand growth in the FF supply area, with the cost of unplanned asset failure represented by a lower value of EUE compared with Option 1.

The capital cost of Option 4 is approximately $6.70M ($2023 real).

4.5 Preferred network option

The preferred network option is Option 2 as it is the option that maximises the present value of net benefits and is the only option that fully addresses the identified need without the support of a non-network or SAPS option. Other options leave some residual reliability of supply risk from the base case, in the absence of additional support from a non-network or SAPS option.

Works would commence in 2024 and be completed in 2026 at a total capital cost of approximately $13.64M ($2023 real). The scope of work includes:

- replacing the existing No.3 22/6.6 kV power transformer, by removing it from the site and installing a new 22/6.6 kV 18 MVA power transformer in another location of the switchyard;

- installing a new fourth 6.6kV bus with new 6.6 kV feeder bays in the location of the existing No.3 22/6.6 kV power transformer;
- other primary assets needed to support the connection of the replaced transformer and new 6.6 kV bus; and
- associated protection and control relays and other secondary assets that monitor, control and protect the above assets.

5. Assessment of non-network options

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

- **Demand Management (DM)** - Any measure or program targeted at reducing peak demand, including direct load control, broad-based demand management, or targeted customer demand response programs.
- **Embedded Generation (EG)** - 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.

Generation solutions within customers' premises or operated within the market could have benefits over the network support benefits that may flow to that customer, improving the economic viability of such solutions. Furthermore, customer demand reduction or standby generation solutions are limited by the demand of that customer, i.e. an individual customer can only reduce its demand to zero.

5.1 Credible scenarios

The aim of 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 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 FF supply area identified need are:

- **Scenario 1** - Meeting the identified need in its entirety through a non-network or SAPS option, allowing the existing FF No.3 transformer to be completely retired and removed from the site and avoiding the need for a replacement transformer and fourth bus. A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon (a level of support up to 14 MW). Smaller non-network or SAPS solutions of at least 6 MW could provide sufficient capacity to defer the preferred network option, increasing the support by 1MW each year.
- **Scenario 2** - Meeting the identified need in part through a non-network or SAPS option, coupled with network option 3. A non-network or SAPS option would need to supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon (a level of support up to 7 MW). Smaller non-network or SAPS solutions of at least 1 MW could provide sufficient capacity to defer the preferred network option, increasing the support by 1MW each year.

No other scenarios have been identified. The option screening criteria are applied in the next section.

5.2 Non-network assessment scenarios

5.2.1 Scenario 1 – Non-network or SAPS option to meet identified need in its entirety

Viable generation options that can supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon, being a level of support of up to 14 MW from an initial level of 6 MW could comprise of:

- 6 MW of generation initially, then 1 MW of generation per annum over 8 years, or
- 14 MW of generation initially.

The maximum viable generator size per distribution feeder ranges from 3 MW to 7 MW based on the ability of JEN's 6.6kV network to connect the generation. The support would only be required (for a single contingency) in the event of the loss of either the No.1 or No. 2 transformer at FF or No.1, No. 2 or 3 bus at FF for periods when the demand exceeds the rating of the remaining in-service transformer. This would enable FF to meet maximum demand in system normal and contingency situations.

Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above. The costs of this scenario are likely to exceed those of the preferred network option. For example, the EPC Capex cost of a small gas-fired generator is approximately $1.25M per MW[5].

For 14 MW of generation, the cost will be over $17.5M. Note, this does not allow for some reduction in generator capacity if the solution is complemented with other non-network demand management and efficiency measures, which could provide a lower cost. This would lead to a higher marginal cost to the customer compared to a network solution cost (of network option 2) of approximately $13.64M, being the capital cost of replacing the No.3 22/6.6kV transformer with a new transformer located in a different area of the switchyard and a fourth 6.6kV bus with new 6.6kV feeder bays. However, this could be offset somewhat by other revenue sources, such as from the market.

Considering this generation cost estimate does not include the cost of purchasing land in this built-up area, grid connection and operating costs, the cost is likely to be significantly higher than the cost of the preferred network option. Furthermore, given the existing noise constraints on the No.3 transformer, there are likely to be additional costs for noise mitigation required for a generation solution. Additionally, the maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need.

5.2.2 Scenario 2 – Non-network or SAPS option to meet identified need in part

Viable generation options that can supply any shortfalls in FF meeting the forecast demand during the 10-year planning horizon coupled with network option 3, being a level of support of up to 7 MW from an initial level of at least 1 MW, could comprise of

- 1 MW of generation initially, then 1 MW of generation per annum over 6 years, or
- 7 MW of generation initially.

The maximum viable generator size per distribution feeder ranges from 3 MW to 7 MW, based on the ability of JEN's 6.6kV network to connect the generation. The support would only be required (for a single contingency) in the event of the loss of the No.1 or No. 2 transformer at FF for periods when the demand exceeds the rating of the remaining in-service transformer. This would enable FF to meet maximum demand in system normal and contingency situations.

Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above. The costs of this scenario are likely to exceed those of the preferred network option. For example, the EPC Capex cost of a small gas-fired generator is approximately $1.25M per MW[6].

For 7 MW of generation, the cost will be over $9M. Note, this does not allow for some reduction in generator capacity if the solution is complemented with other non-network demand management and efficiency measures, which could provide a lower cost.

This would lead to a higher marginal cost to the customer compared to a network solution cost (of network option 4) of approximately $6.70M, being the capital cost of replacing the No.3 22/6.6kV transformer with a new transformer located in a different area of the switchyard. However, this could be offset somewhat by other revenue sources, such as from the market.

5 2020 Costs and Technical Parameter Review – Consultation Report for AEMO – Aurecon.

6 2020 Costs and Technical Parameter Review – Consultation Report for AEMO – Aurecon.

Considering this generation cost estimate does not include the cost of purchasing land in this built-up area, grid connection and operating costs, the cost is likely to be significantly higher than the cost of the preferred network option. Furthermore, given the existing noise constraints on the No.3 transformer, there are likely to be additional costs for noise mitigation required for a generation solution. Additionally, the maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need.

5.3 Non-network assessment overview

This section reports on the credibility of potential non-network options as alternatives or supplements for the Fairfield replacement works. The criteria used to assess the potential credibility were:

- **Addressing the identified need**: reducing or eliminating the safety and supply reliability risk associated with the assets in poor condition.
- **Being technically feasible**: there are no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Commercially 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 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 did not find any of the 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 and storage options is 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	Commercial	Timing
1.0 Generation and Storage				
1.1 Generation using gas turbines or diesel				
1.2a Generation using grid-scale renewables (solar)				
1.2b Generation using grid-scale renewables (wind)				
1.3 Standby generation (large customer)				
1.4 Battery energy storage (grid-connected)				
2.0 Demand management				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Broad-based demand response				
2.4 Targeted demand response				

5.4 Non-network assessment

5.4.1 Generation and storage

The assessment rationale for each of the generation and storage options is as follows:

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

Identified need - Capable of meeting the identified needs by providing multiple gas turbine or diesel generators (met).

Technical - Significant constraints and barriers to deployment of equipment to generate 7 - 14 MW in a dense urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). In addition, we cannot establish the availability of a suitable high-pressure gas pipeline in the locality that is essential for this type of generation (not met).

Commercial - Costs of this generation type appear much higher than the network alternatives even before land, grid connection and operating costs are included, as detailed in the scenarios of Section 5.2. Non-network proponents rather than Jemena would bear the cost of these additions and they would recoup these costs through selling power generated (and other services) through the market. The scale of estimated capital costs illustrates the quantum of additional capital costs compared to a network solution and this will lead to a much higher cost per MWh compared to the preferred network solution (not met).

Timing – 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 6.6kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall – not a potentially credible option.

- **Generation using grid-scale renewables (solar) (1.2a):**

Identified need – Unlikely to meet or meaningfully contribute to the identified need. Generation of 7 – 14 MW (the amount required for a viable non-network option) using solar PV is likely to require up to 50 acres of land[7]. Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. As noted in Section 5, solar PV installations in FF provide a capacity of 5 MW. The amount of solar PV required is more than double or triple this. In addition, the generation profile of solar power will not align with the consumption profile of consumers, requiring either an overbuild of generation or complementing storage (not met).

Technical – While it is technically feasible to use this well-understood and applied technology for this type of power generation, there are significant constraints to the deployment of a grid-scale solar PV facility to generate 7 – 14 MW in this locality. These include zoning, planning and environmental constraints (given the land requirements), and the lack of evidence of the availability of up to 50 acres for this type of purpose (not met).

Commercial – Costs of this type of generation are unlikely to be commercially viable or comparable with the costs of network alternatives if the generation profile is required to support the demand profile, requiring substantial amounts of storage to support the installation. Furthermore, the costs in the Fairfield environment of purchasing up to 50 acres of land are likely to be significant. This is unlikely to be cost-effective when compared with the network alternatives (not met).

Timing - Planning processes and the nature of the investment, together with design requirements (both for the generators and any required 6.6kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

- **Generation using grid-scale renewables (wind) (1.2b)**

Identified need - Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land[8], a 7 - 14 MW wind farm would require 5 - 10 acres. Utilising this amount of land for a wind farm with tall turbines in a dense, urban environment is unlikely to be feasible (not met).

Technical - It is unclear whether there is an adequate site available in terms of elevation, and wind conditions for wind generation (for example). The planning constraints and environmental factors involved in securing planning permission for using land for this purpose are very significant and the use of land for this purpose is unlikely to be allowed. (not met).

Commercial - The cost of acquiring land and installing wind turbines is likely to significantly exceed the costs of the preferred network solution, which means this form of generation is unlikely to be viable. Storage may also be needed to cater for the intermittency of wind (not met).

7 https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1.

8 https://sciencing.com/much-land-needed-wind-turbines-12304634.html.

Timing - Planning processes and the nature of the investment with likely height objections, together with design requirements (both for the generators and any required 6.6kV connections to FF) mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

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

Identified need - As noted in Section 3.2.1, 12 industrial customers are consuming 3 MVA at the summer peak and 776 commercial customers consuming 8 MVA. It is unlikely that a small number of industrial customers is consuming sufficient energy for this type of generation to provide a viable non-network option. The practical difficulties of expanding this to coordinating generation efforts for a larger number of commercial customers are too great for this to be viable. Jemena believes low levels of connections for larger embedded generators are due to a reflection of the nature of the JEN network, which services the northeast of greater metropolitan Melbourne, where there is limited availability of physical space for significantly sized embedded generators and significant environmental limitations. Instead, there is a preference for smaller-scale embedded generation, particularly rooftop solar PV, for which Jemena has seen an ongoing increase in installed capacity on its network (not met).

Technical - This type of generation is unlikely to be technically feasible within the very small number of existing industrial sites (not met).

Commercial - The estimated cost of a relatively small generator (4 MVA) is about $3.9M and 6.5 MVA about $5.6M both excluding installation and operating costs. To provide the 7 - 14MW needed, 2 to 4 of these would be required. This is unlikely to be commercially viable and too large for customers connected within the 6.6kV distribution network of FF, given the lower costs of providing this capacity using a network solution (not met).

Timing - Planning processes, the nature of the investment and likely obstacles, together with design requirements mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

- **Battery energy storage (grid-connected) (1.4)**

Identified need - A viable storage option would involve deploying strategically located grid-connected battery energy storage systems totalling 7 – 14 MW, each with an energy-to-power ratio of around 5. (not met).

Technical - This type of technology is technically feasible but would face planning and technical constraints (not fully met).

Commercial - The estimated cost of storage is approximately $1.0M per MWh. For 14 MW of batteries, the cost will be over $70M, excluding land, connection and operating costs, well over any credible network option. (not met).

Timing - Planning processes, the nature of the investment and likely obstacles, together with design requirements mean this is unlikely to be completed by 2026 (not met).

Overall - not a potentially credible option.

5.4.2 Demand management/Efficiency

The assessment rationale for the demand management/efficiency options is as follows:

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

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

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

Commercial - This could be cost-effective (met).

Timing - This option could be completed by 2026 (met).

Overall - not a potentially credible option.

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

Identified need - As noted in Section 3.2.1, solar PV customer premises penetration in the FF supply area is around 12% with 5MW of installed capacity. Approximately 1,400 - 2,800 additional FF supply area customers (15 - 30% of remaining customers) would need to have a 5kW solar PV system installed to provide 7 - 14 MW capacity. This rate of take-up is considered to be achievable, but not within the timeframe (not met).

Technical - This option is technically feasible and the technology is well understood and tested (met).

Commercial - Achieving a greater than average solar PV take-up would require a financial incentive and to achieve the level of take-up for this option to be potentially credible would require a very high subsidy (not fully met). The systems are also likely to require storage to be able to support late afternoon and early evening demands, reducing the commercial viability of this solution (not fully met).

Timing - This option could be completed by 2026 but there is uncertainty given the large number of customers that would need to install solar PV (not fully met).

Overall - not a potentially credible option.

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

Identified need - The assessment for this option is similar to the results for option 2.2. Each of Jemena's customers would have to reduce consumption by approximately 20 - 40% for the summer peak to achieve a 7 - 14 MW reduction (14 MW / 36 MW[9] = 40%). This scale of reduction (in magnitude and for every customer) is considered unrealistic even if accompanied by subsidies to consider doing this (not met).

Technical - This option is not technically feasible given the size of the demand reduction required and the number of customers needing to participate (not fully met).

Commercial - Unclear that this is commercially feasible, as the payments to customers could be substantial to achieve such high levels of demand reduction. (not fully met).

Timing - This type of mass action would be difficult to promote and implement by 2026 (not fully met).

Overall - not a potentially credible option.

- **Targeted demand response (2.4)**

This option has a similar assessment profile to options 1.3 and 2.3. The targeted nature of the response will allow for the optimisation costs. However, given customer uptake rates of the program are likely to be no higher than 20%, this is insufficient to meet the 7 – 14 MW of demand response needed in the supply area.

Overall - not a potentially credible option.

[9] The forecast peak demand in 2033.

6. Conclusion and next steps

6.1 Conclusion

In conclusion, it is unlikely that a non-network or SAPS option could be technically and economically feasible to address the identified need in this instance. In addition, the analysis demonstrates that there are no combinations of non-network or SAPS options, or non-network and network options, that are likely to adequately meet the criteria that would necessitate the production of an options screening report.

6.2 Next Steps

The total cost of the most expensive credible network option to address the identified need is greater than the trigger threshold of $12 million[10] for the publication of and consultation on a Draft Project Assessment Report (DPAR).

Jemena will therefore prepare a DPAR, which will present a detailed assessment of all network options to address the identified need. The DPAR will apply the latest available information on demand forecasts, VCR estimates and project cost estimates.

We intend to publish the DPAR by 25 August 2023. Further consultation, in accordance with the RIT-D process set out in the Rules, will then proceed.

10 Source: AER 2021 RIT and APR cost thresholds review (November 2021).