Jemena Electricity Networks (Vic) Ltd

Footscray West Zone Substation (FW) Transformers, Switchgear and Relay Condition Risk

RIT-D Stage 1: Non-Network Options Screening Report

Notice of determination under clause 5.17.4(c) of the National Electricity Rules

An appropriate citation for this paper is:

Footscray West Zone Substation (FW) Transformers, Switchgear and Relay Condition Risk

Authorisation

Name	Job Title	Date	Signature
Reviewed by:			
Andy Dickinson	Future Network & Planning Manager	6/10/2022	Andy Dickinson
Approved by:			
Karl Edwards	General Manager Asset & Operations - Electricity	6/10/2022	Karl Edwards

History

Rev No	Date	Description of changes	Author
1	18/09/2018	First release	Manoj Ghimire
2	04/10/2022	Second release	Rodney Bray

Owning Functional Area

Business Function Owner:	Asset & Operations – Electricity | Jemena Networks

Review Details

Review Period:	N/A
NEXT Review Due:	N/A

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[1]

Footscray West zone substation (**FW**) is owned and operated by Jemena, providing power to approximately 14,385 customers in the suburbs of Yarraville, Kingsville and West Footscray, in Melbourne's inner west.

The condition of the 66/22kV transformers, 22kV switchgear, protection relays and other equipment within FW is deteriorating. Jemena has assessed that there is now an unacceptable risk of asset failure, with significant consequences for staff safety and the reliability of electricity supply to Jemena's customers within the supply area. While there is a need to remove these assets from service, there also remains a need to continue to supply electricity to customers within the area supplied by these assets.

The most urgent concern for Jemena is the evidence of escalating partial discharges (**PD**) from the switchgear, and the threat this poses to staff safety and customer supply reliability. Removing the aged switchgear from service is a priority task given the risk will increase further over time. A further concern is that two of the three existing power transformers are more than 56 years old and are showing signs of accelerating condition deterioration as they approach end-of-life. The third power transformer contains toxic, carcinogenic Polychlorinated Biphenyl (**PCB**) oil. The protection systems around these assets are also deteriorating and no longer considered fit for purpose.

Approach to screening options

Jemena has developed a set of potential network solutions to remediate the asset condition risks at FW. It 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(e).

This report considers the credibility of potential non-network and SAPS options as alternatives to, or supplements for the FW transformer, switchgear and protection relay network options. This is in the context of a non-network or SAPS option being able to supply the forecast maximum summer load at FW of up to 64MW during the 10-year planning horizon. This would allow all of the assets in poor condition to be retired completely. Alternatively, a non-network solution supplying 31MW may be feasible, if used in conjunction with a scaled-down network option. Smaller non-network or SAPS solutions would not provide sufficient capacity to be credible options.

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 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.

[1] This is a re-application of the RIT-D for the Footscray West Zone Substation (FW) Switchgear and Relay Condition Risk need, because the identified need has been expanded to also address the Transformer Condition Risk need at the same site.

- **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 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 RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 Gas turbine power station				
1.2a Generation using renewables (solar)				
1.2b Generation using renewables (wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
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 notifies that the publication of a non-network options screening report is not required for this identified need.

The remainder of this report provides the evidence underpinning this determination that non-network options or SAPS options do not provide potential credible options for addressing the identified need in this instance.

Table of contents

List of tables

List of figures

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.
Expected unserved energy (EUE)	Refers to an estimate of the long-term, probability-weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for 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.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 355,000 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 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 ability 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)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a prescribed limit, in the National Electricity Market (NEM).
System Normal (or 'N' condition)	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices
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 Jemena Electricity Network (JEN)
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, 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 derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	50% POE and 10% POE conditions (winter) are treated the same, referring 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
DM	Demand Management
DPAR	Draft Project Assessment Report
EG	Embedded Generation
EUE	Expected Unserved Energy
FW	Footscray West 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
MWp	Megawatt peak
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

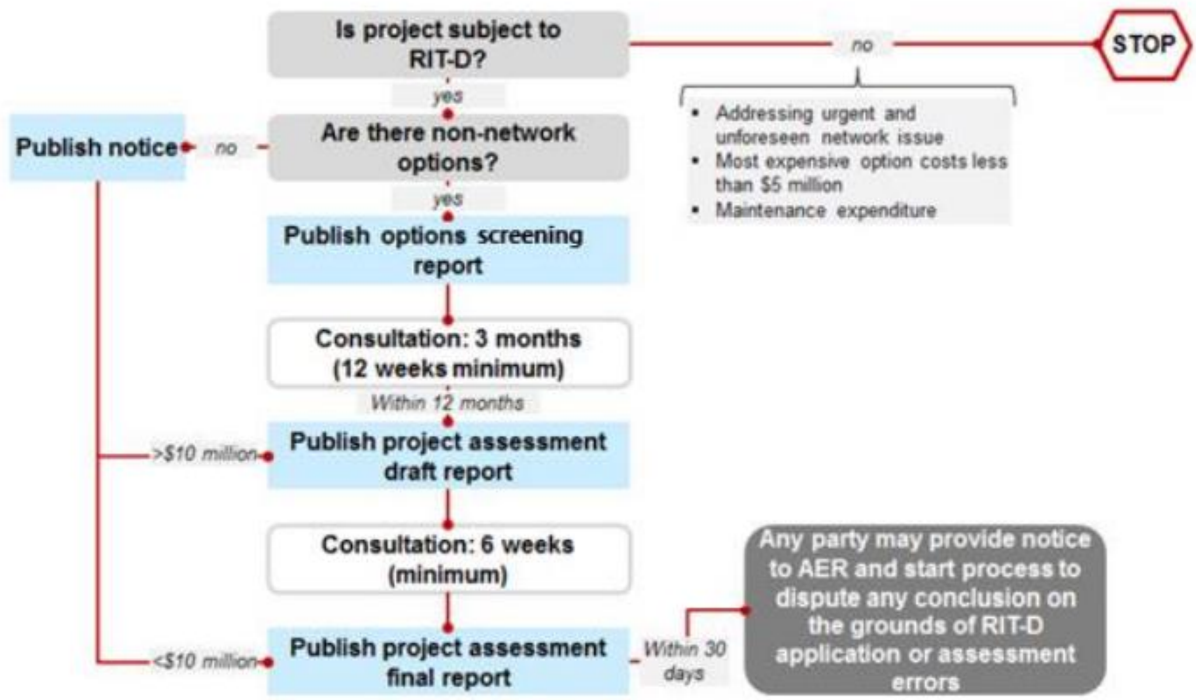
1. Introduction

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[2].

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[3]



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 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)
- States the conclusion reached on the need for an options screening report (Section 6).

[2] In accordance with the Australian Energy Regulator (**AER**) Application Guidelines RIT-D, from 1 January 2019 this cost threshold has been changed to $6 million.

[3] Source: 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**), dated August 2022; and
  - National Electricity Rules (**NER**), Version 188.
- 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 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 full range of non-network options against the criteria in Clause 5.15.2(a) of the NER described above; and
- 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 and project objectives

Jemena has prepared this report to assess whether the reliability and safety needs of the Footscray West Zone Substation (**FW**) could be realised either fully, or in part through non-network or SAPS options. 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 FW as a priority for investment based on two key needs:

1. Firstly, the need to protect power sector workers and members of the public from harm caused by equipment failure (safety); and
2. 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 is limited by the poor and deteriorating condition of electrical equipment at the FW zone substation. This poses a serious safety risk due to the possibility of asset failure.

3.1.1 Condition of network assets

The need is driven by the poor condition of the power transformers, switchboards and circuit breakers at FW, which are at risk of failure and pose a serious safety risk. The presence of partial discharges means that the 85-year-old switchgear needs to be replaced as an urgent priority to mitigate significant safety risks to Jemena staff. A further concern is that two of the three existing power transformers are more than 56 years old and are showing signs of accelerating condition deterioration as they approach end-of-life, with the third power transformer containing toxic, carcinogenic PCB oil.

In addition, the protection and control relays at this zone substation have deteriorated. There is a significant risk that faults will not be detected and isolated, with failure leading to potential impacts on safety and supply reliability.

The potential safety risks of a network asset failure are listed below:

- Severe injury or death to Jemena's operating personnel and the general public in the vicinity of the substation;
- Risk of step and touch potentials causing electrocution; and
- Risk to the public of an extended period of power supply interruptions.

3.1.2 Credible solution requirements

Credible solutions would be required to allow the decommissioning of the existing transformers, switchboards and relays to ensure the safety of staff and the public.

3.2 Reliability

Jemena's planning standard for its zone substation assets is based on a probabilistic planning approach that:

- Directly measures customer (economic) outcomes associated with current and future network limitations;
- Provides a thorough cost-benefit analysis evaluation of network or non-network augmentation options; and
- Estimates Expected Unserved Energy (**EUE**), which is defined in terms of megawatt hours (MWh) per annum and expresses this economically by applying 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 if any single item of equipment was out of service (called a normal minus one or N-1 scenario), taking into account the probability of an asset failure.

A credible non-network or SAPS solution should seek to maintain levels of supply reliability that are at threat from deteriorating asset condition. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply the load under N and N-1 network conditions, in which the cost of expected unserved energy at risk exceeds the annualised cost of the investment.

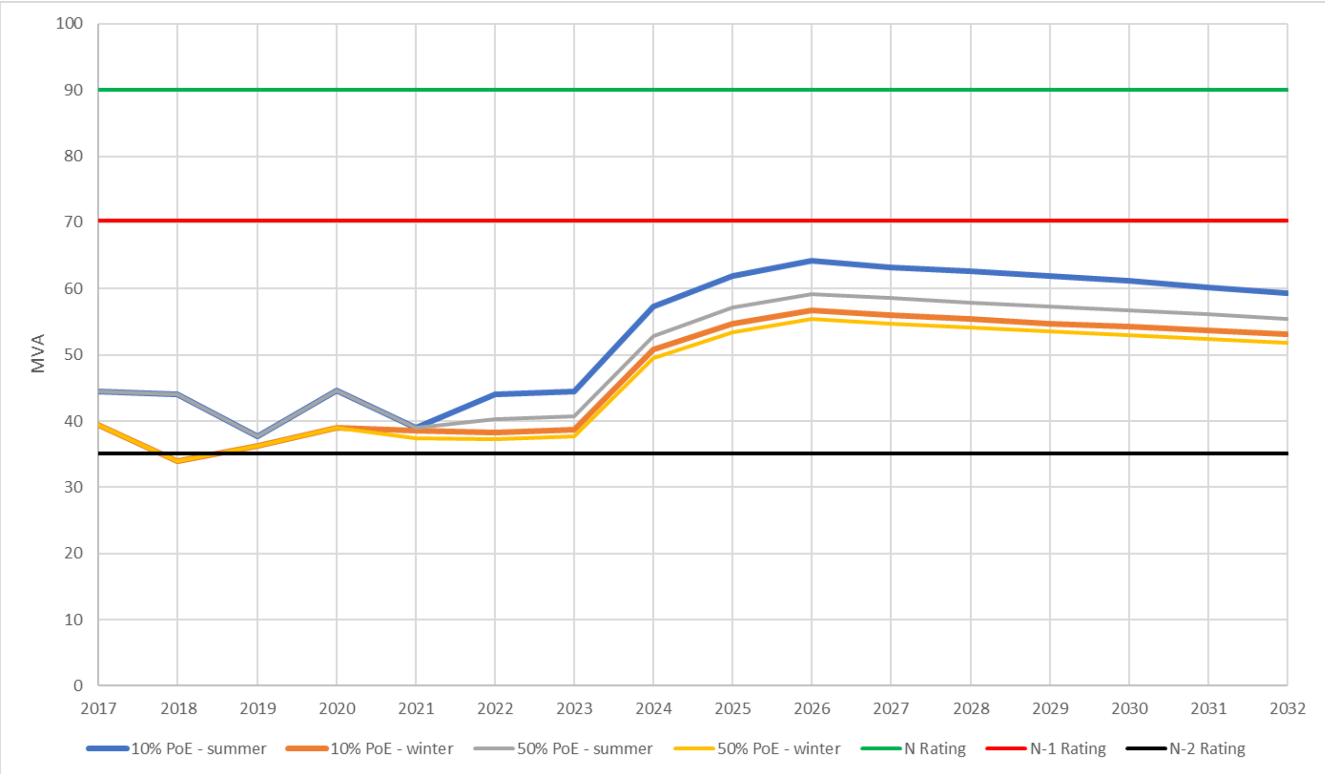
The value of the EUE will depend on the topology and capacity of the existing network and the forecast load, presented below in Sections 3.2.1 and 3.2.2.

3.2.1 Maximum demand forecasts

The maximum demand forecasts for FW are shown below in Figure 3–1. Maximum demand is forecast to increase rapidly over the next few years as a result of some large customer connections occurring in the FW supply area, on a backdrop of marginally declining underlying maximum demand.

The FW maximum demand is forecast to be 44.4MVA for the summer of 2023 under 10% Probability of Exceedance (**PoE**). By 2032, it is forecast that maximum demand will be approximately 59.4MVA. The highest maximum demand over the 10-year planning horizon is forecast to be 64.3MVA for the summer of 2026.

Figure 3–1: FW maximum demand forecast and ratings (MVA)



3.2.2 Substation capacities

The zone substation assets limiting the summer and winter capacity at FW are the 66/22kV power transformers' thermal limits. FW consists of three 66kV/22kV power transformers, two 66kV bus-tie circuit breakers and eight 22kV feeders from three 22kV indoor switchboards. The ratings of the key assets are:

- Three transformers rated at 30MVA continuous each, with a cyclic rating of 35MVA;
- Three 22kV buses each rated at 1,200 Amps with space for 4 circuit breakers on each switchboard, of which:
  - eight are currently used for feeder circuit breakers to supply customers in the FW supply area
  - two are used for capacitor banks that provide 9.14MVAr and 14.6MVAr for power factor correction.

The total nameplate rating of the zone substation is 90MVA. The N-1 rating is based on the transformer cyclic rating of 35MVA. With two of the three transformers in service, the N-1 rating is 70MVA.

3.2.3 Credible solution requirements

While there is presently sufficient capacity to supply the forecast maximum demand at FW with the existing assets, with poor condition assets needing to be derated or removed from service, there is a risk of deteriorating supply reliability because of reduced capacity. This would be observed by customers as more frequent and longer power supply outages.

To maintain reliability levels, credible solutions would be required to address a deteriorating reliability need. This could be achieved through a range of solutions, including:

- Meeting the identified need in its entirety through a non-network or SAPS option, allowing all of the poor condition assets at FW to be retired;
- Replacing one switchboard, one transformer and the associated protection and control relays at FW providing 30MVA of capacity, with the residual need addressed through a non-network option to allow those assets to be retired;
- Replacing two switchboards, two transformers and the associated protection and control relays at FW providing 60MVA of capacity, with the residual need addressed through a non-network option to allow those assets to be retired;
- Replacing all three switchboards, three transformers and the associated protection and control relays at FW providing 90MVA of capacity, with no non-network options, allowing all of the poor condition assets at FW to be replaced.

A non-network or SAPS option would need to supply the forecast maximum summer load at FW over the 10-year planning horizon of 64MW. This would allow all of the assets in poor condition to be retired.

A non-network solution supplying 31MW may be feasible, if used in conjunction with part of a network asset replacement option, i.e. used in conjunction with the replacement (rather than retirement) of a network asset.

Non-network or SAPS solutions smaller than 31MW would not provide sufficient capacity to be credible options.

4. Network options

Jemena has identified four network options that attempt to address the identified need:

1. Option 1 – Base case "Do Nothing"[4], i.e., run assets to failure;
2. Option 2 – Replace one switchboard, one transformer and their relays at FW;
3. Option 3 – Replace two switchboards, two transformers and their relays at FW; and
4. Option 4 - Replace all three switchboards, three transformers and their relays at FW.

Each network option, except Option 1, has two sub-options:

1. Sub-option 'a' – In-situ: replace poor condition assets with new assets in the same switchyard location; and
2. Sub-option 'b' – Rebuild: retire poor condition assets with new assets established in a vacant area of the switchyard.

4.1 Option 1 – Do nothing

Option 1 involves running the switchgear, transformers and relays at FW to failure. The capital cost of this option is assumed to be zero, with the cost of unplanned asset failure represented by the value of EUE and the safety risk cost.

4.2 Option 2 – Replace one switchboard, one transformer and associated relays at FW

Option 2 involves replacing one switchboard, one transformer and their associated protection and control relays at FW, leaving the remaining assets run to failure, with the cost of unplanned asset failure represented by a lower value of EUE and safety risk cost compared with Option 1.

The capital cost of Option 2a is approximately $22.0M ($2022 real) for an in-situ replacement.

The capital cost of Option 2b is approximately $20.0M ($2022 real) for a rebuild of FW.

4.3 Option 3 – Replace two switchboards, two transformers and associated relays at FW

Option 3 involves replacing two switchboards, two transformers and their associated protection and control relays at FW, leaving the remaining assets run to failure, with the cost of unplanned asset failure represented by a lower value of EUE and safety risk cost compared with Option 2.

The capital cost of Option 3a is approximately $32.0M ($2022 real) for an in-situ replacement.

The capital cost of Option 3b is approximately $30.0M ($2022 real) for a rebuild of FW.

4.4 Option 4 – Replace three switchboards, three transformers and associated relays at FW

Option 4 involves replacing all three switchboards, transformers and their associated protection and control relays at FW, resulting in zero residual EUE and safety risk cost.

The capital cost of Option 4a is approximately $42.2M ($2022 real) for an in-situ replacement.

[4] Consistent with the AER's *Industry practice application note for asset replacement planning,* January 2019.

The capital cost of Option 4b is approximately $40.6M ($2022 real) for a rebuild of FW.

4.5 Preferred network option

The preferred network option is Option 4b as it maximises the present value of net benefits and is the only option that fully addresses the identified need. Other options leave some residual safety and supply reliability risk compared with the base case.

Works would commence in 2023 and be completed in 2025 at a total capital cost of approximately $40.6M ($2022 real). The scope of work would include replacing:

- three 66kV/22kV power transformers;
- three 22kV switchboards including their associated switchgear;
- other primary assets such as outdoor buses and feeder exit cables; 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 customer premises or operated within the market could have benefits above the network support benefits that may flow to that customer, improving the economic viability of such solutions.

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. Typically, the absence of large customers limits the potential for large demand-side solutions.

Demand composition and customers

At FW, the share of maximum demand from 14,385 customers forecast to be consuming up to 44.4MVA of coincident net load in summer 2023 comprises:

- 13,550 residential customers consuming 19.9MVA peak summer load (average 0.0015MVA)
- 805 commercial customers consuming 8.2MVA of peak summer load (average 0.01MVA)
- 30 industrial customers consuming 16.3MVA of peak summer load (average of 0.54MVA).

For FW, the two largest industrial (HV) customers are:

- Customer 1 (Maximum demand – 1.7MVA)
- Customer 2 (Maximum demand – 1.4MVA)

Currently, there is no HV-connected embedded generation supplied from the FW zone substation other than the small residential and commercial solar PV. At FW, there are 1,559 solar PV installations with a capacity of 6.7MW[5].

5.1 Credible 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 FW are:

- Meeting the identified need in its entirety through a non-network or SAPS option, allowing all of the poor condition assets at FW to be retired;
- Replacing one switchboard, one transformer and the associated protection and control relays at FW providing 30MVA of capacity, with the residual need (i.e. from the remaining in service poor condition assets) addressed through a non-network option;

[5] As at 8 September 2022.

- Replacing two switchboards, two transformers and the associated protection and control relays at FW providing 60MVA of capacity, with the residual need (i.e. from the remaining in service poor condition assets) addressed through a non-network option; and
- Replacing three switchboards, three transformers and the associated protection and control relays at FW providing 90MVA of capacity, with no non-network options, allowing all of the poor condition assets at FW to be replaced.

A non-network or SAPS option would need to supply the forecast maximum summer load at FW of 64MW over the 10-year planning horizon. This would allow all of the assets in poor condition to be retired. A non-network solution supplying 31MW may be feasible if used in conjunction with part of a network asset replacement option. Smaller non-network or SAPS solutions would not provide sufficient capacity to be credible options.

The option screening criteria is applied in the next section.

5.2 Non-network assessment scenarios

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

A viable generation option that meets the maximum demand at FW of 64MVA, which reliably meets customer requirements in an N-1 situation requires:

- two generators each able to supply 64 Megawatt peak (**MWp**);
- three generators each able to supply 32MWp; or
- ‘N’ generators each able to supply 64MWp ÷ (N-1).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator out of service). 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 capital expenditure cost of a small gas-fired generator is approximately $1.25M per MW[6].

For two 64MW generators, the cost will be over $160M, excluding land, connection and operating costs. 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 much higher marginal cost to the customer compared with a network solution cost of approximately $40.6M, being the capital cost of the replacement of all three switchboards, transformers and secondary equipment.

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 option and replace one switchboard and one transformer

If only one switchboard, one transformer and related protection relay assets were replaced providing the network capacity equivalent to one transformer (30MVA), a viable, non-network would be required to supply enough power, and/or enable a sufficient reduction in demand, to supply the peak load should the single transformer or switchboard combination fail.

[6] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

A viable generation option that meets the maximum demand at FW of 64MVA, that reliably meets customer requirements in an N-1 situation requires:

- two generators each supplying 32MWp; or
- three generators each supplying 22MWp; or
- 'N' generators each supplying 64MWp ÷ (N).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator or one power transformer out of service). Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

This is likely to cost at least $80M, excluding land, connection and operating costs. 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 much higher marginal cost to the customer compared with a network solution cost of approximately $30.0M, being the incremental capital costs of the avoided replacement of the remaining two switchboards, transformers and secondary equipment.

5.2.3 Scenario 3 – Non-network option and replace two switchboards and two transformers

The most realistic scenario for a non-network option making a potentially credible contribution to meeting the identified need is where it allows for a reduced level of investment below the network option of replacing three switchboards and the associated relay assets.

Accordingly, Jemena considered the potential credibility of non-network options for covering the gap when only two switchboards and transformers are replaced at FW so it has a new configuration of two switchboards and two transformers with an N-1 capacity of 33MVA. With this reduced investment (and no permanent load transfers), a non-network option would need to cover the failure of a transformer or one of the switchboards. This would leave a shortfall of 64MVA – 33MVA = 31MVA.

A viable generation option that meets the maximum demand at FW of 64MVA, that reliably meets customer requirements in an N-1 situation requires:

- one generator supplying 31MWp;
- two generators each supplying 15MWp; or
- 'N' generators each supplying 31MWp ÷ (N).

This would enable the system to meet maximum demand in an N-1 situation (i.e. one generator or one power transformer out of service). Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

This is likely to cost at least $39M, excluding land, connection and operating costs. 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 much higher marginal cost to the customer compared with approximately $20.0M, being the incremental capital costs of the avoided replacement of the remaining switchboard, transformer and secondary equipment at FW.

5.3 Non-network assessment overview

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

- **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; and
- **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 isolation 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 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
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 commentary

5.4.1 Generation and storage

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

- **Gas turbine power station (1.1)**

Identified need – Reduces risks of running poor condition assets beyond their end of life. Capable of meeting the identified need by providing multiple gas turbine generators (met).

Technical – Significant constraints and barriers to deployment of equipment to generate up to 64MW 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 type of generation appear much higher than the network alternatives even before land, connection and operating costs are included, as detailed in the scenarios of Section 5.2. We note that 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 process and nature of the investment and likely objectives, together with design requirements (both for the generators, gas connections and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

- **Generation using renewables solar (1.2a)**

Identified need – Reduces risks of running poor condition assets beyond their end of life. Unlikely to meet or meaningfully contribute to the identified need. Generation of 31MW (the minimum required for a viable non-network option) using solar PV is likely to require more than 100 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 FW provide a relatively small capacity of 6.7MW. In addition, the generation profile of solar power may not align to 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 solar PV facility to generate 31MW in this locality. These include zoning, planning and environmental constraints (given the land requirements), and the lack of evidence of the availability of more than 100 acres for this type of purpose (not met).

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

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 Footscray environment of purchasing up to 100 acres of land are likely to be significant. This is unlikely to be cost-effective when compared to the network alternatives (not met).

Timing – Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

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

Identified need – Reduces risks of running poor condition assets beyond their end of life. Unlikely to meet or meaningfully contribute to the identified need. Based on a 2MW wind turbine requiring 1.5 acres of land[8], a 31MW wind farm would require 24 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).

Timing – Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

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

Identified need – Reduces risks of running poor condition assets beyond their end of life. 30 industrial customers will consume 16.3MVA at the summer peak and 805 commercial customers will consume 8.2MVA. As noted in section 5, there are only two large industrial (HV) customers with maximum demands of 1.7MVA and 1.4MVA. It is unlikely that a small number of industrial customers will consume sufficient energy for this type of generation to provide a viable non-network option. The practical difficulties of coordinating generation efforts for a large number of small consumers 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. 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 technically feasible within existing industrial sites but would face planning and technical constraints (not fully met).

Commercial – The estimated cost of a relatively small generator (4MVA) is about $3.9M and 6.5MVA about $5.6M, both excluding installation and operating costs. To provide the minimum 31MW needed, 5 to 8 of these would be required. This is unlikely to be commercially viable and too large for customers connected within the 22kV

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

distribution network of FW, given the much 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 (both for generators and any required 22kV connections to FW) mean this is unlikely to be completed by 2025 (not met).

Overall – not a potentially credible option.

- **Large customer energy storage (1.4)**

The responses to this option (1.4) are similar to option 1.3. The overall finding that this is not a potentially credible option is driven by the relatively small power requirements per industrial customer and the need to coordinate efforts across many power users–this is likely to be time consuming and difficult to achieve. In addition, the costs associated with battery storage to manage peak demand and therefore reduce the scope of the non-network project are likely to be high compared with the marginal costs for a full network solution.

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 FW 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 (fully met).

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

Timing – This option could be completed by 2025 (fully met).

Overall – not a potentially credible option.

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

Identified need – Reduces risks of running poor condition assets beyond their end of life. Solar PV customer premises penetration in Jemena is approaching 15%. For the FW supply area, 1,559 of 14,385 customers (11%) have a solar PV system installed. Approximately 6,200 additional FW customers (54%) would need to have a 5kW solar PV system installed to provide 31MW capacity. Currently, as noted in Section 5, solar PV installations in FW provide a relatively small capacity of 6.7MW. This uptake rate is not considered to be achievable (not met).

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

Commercial – Achieving a greater than average solar PV uptake would require a financial incentive and achieving the level of uptake 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 2025 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 48% for the summer peak to achieve a 31MVA reduction (31MVA/64MVA = 48%). 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 met).

Commercial – It is unclear whether 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 2025 (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 1.4. All options essentially rely on the actions of a small number of high-consumption users. There is no evidence that a small number of very large users would curtail load and hence this is unlikely to meet the identified need. We also do not think this is likely to be commercially feasible or achievable within the intended timing of the network solution.

Overall – not a potentially credible option.

6. Conclusion and next steps

6.1 Conclusion

In conclusion, the evidence shows that none of the non-network or SAPS options are potentially feasible.

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

Jemena will prepare a draft project assessment report (**DPAR**) that 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 28 October 2022. Further consultation, in accordance with the RIT-D process set out in the NER, will then proceed.