

Jemena Electricity Networks (Vic) Ltd

Footscray East (FE) Switchgear Condition Risk

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

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Footscray East (FE) Switchgear Condition Risk

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EXECUTIVE SUMMARY

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network 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 emerging network issues. This means choosing the solution that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Identified Need

The condition of the 22 kV switchgear at Footscray East (FE) Zone Substation is deteriorating. The switchgear is non-compliant with current arc fault containment standards and the switchgear condition has degraded to a point where employee safety, reliability and security of customer supply will be affected. Recent testing of the switchgear has indicated decreased insulation resistance and polarisation index from previous testing in 2008. The magnitude of the partial discharge (PD) above the service voltage level has also increased on all phases from the previous measurements in 2008 on the no.1 22 kV bus. The 66 kV bus tie circuit breaker (CB) represents a family of breakers with a history of failure. Catastrophic failure of the primary insulation risks the safety of employees and security of customer supply.

Summary of findings

The criteria used to assess the potential credibility of non-network options were:

- Addresses the identified need: by delivering energy to reduce or eliminate the need for investment
- Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
- Commercially feasible: non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
- Timely and can be delivered in a timescale that is consistent with the identified need.

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

Table 1–1: Assessment criteria rating

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

Table 1–2 shows the initial assessment of non-network options against the Regulatory Investment Test for Distribution (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	Green	Red	Red	Red
1.2a Generation using renewables (Solar)	Red	Red	Red	Red
1.2b Generation using renewables (Wind)	Red	Red	Red	Red
1.3 Dispatchable generation (large customer)	Red	Yellow	Red	Red
1.4 Large customer energy storage	Red	Yellow	Red	Red
2.0 Demand management				
2.1 Customer power factor correction	Red	Green	Green	Green
2.2 Customer solar power systems	Red	Green	Yellow	Yellow
2.3 Customer energy efficiency	Red	Green	Yellow	Yellow
2.4 Demand response (curtailment of load)	Red	Yellow	Red	Red

Jemena has concluded that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Hence, under National Electricity Rules (NER) clauses 5.17.4(c) and 517.4(d), the publication of a non-network options report is not required.

The remainder of this report provides the evidence underpinning the conclusion that a non-network options report is not required.

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GLOSSARY

Constraint	Refers to a constraint on network power transfers that affects customer service.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 319,000 customers via an 11, 000 kilometre distribution system covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or inter) and year.
Megavolt ampere MVA	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
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 options	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 certain limit (\$5M), in the National Electricity Market (NEM).

ABBREVIATIONS

AER	Australian Energy Regulator
BY	Braybrook Zone Substation
CB	Circuit Breaker
DAPR	Distribution Annual Planning Report
DM	Demand Management
EG	Embedded Generation
FE	Footscray East Zone Substation
FW	Footscray West Zone Substation
JEN	Jemena Electricity Networks
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
PoE	Probability of Exceedance
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability
YVE	Yarraville Zone Substation

1. BACKGROUND

The condition of the 22 kV switchgear at Footscray East (FE) Zone Substation is poor. The switchgear is non-compliant with current arc fault containment standards and the switchgear condition has degraded to a point showing evidence of decreased insulation resistance and polarisation index from previous testing in 2008. The magnitude of the partial discharge (PD) above the service voltage level has also increased on all phases from the previous measurements in 2008 on the no.1 22 kV bus. The condition of the switchgear is deteriorating where employee safety, reliability and security of customer supply will be affected. The 66 kV bus tie circuit breaker (CB) represents a family of breakers with a history of failure. Catastrophic failure of the primary insulation risks the safety of employees and security of customer supply.

Jemena has developed network solutions to remediate the assets that are in poor condition and to meet the long term demand for electricity in the area.

In November 2017, the Australian Energy Regulator (AER) introduced a new requirement that impacts these plans. It required that a Regulatory Investment Test (RIT-D) should be undertaken that includes the issue of a non-network options report for those projects greater than \$5M in value where a non-network solution is potentially viable. Distribution businesses are required to go through the Regulatory Investment Test for Distribution (RIT-D) process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT-D applies in circumstances where a network problem (an “identified need”) exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than \$5M. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need. Should viable non-network solutions exist, Jemena is required to publish a non-network options report and request stakeholder submissions.

1.1 RIT-D PROCESS

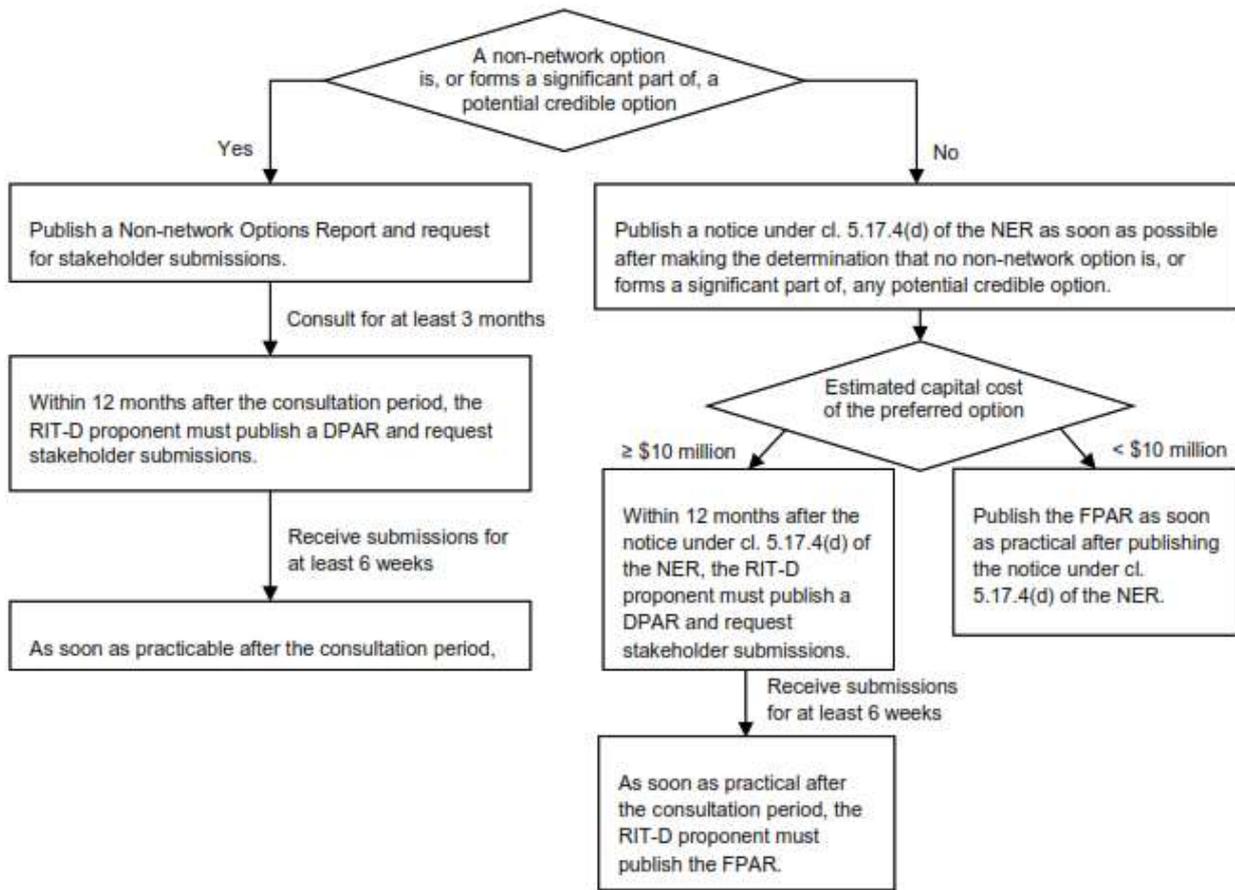
The Regulatory Investment Test for Distribution (RIT-D) process is summarised in Figure 1–1. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- 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 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 options to help address the identified need (Section 5)
- States the conclusion reached on the need for a non-network options report (Section 6).

Figure 1–1: RIT-D Process



Source: AER - Final RIT-D application guidelines - September 2017

2. SCREENING REQUIREMENTS AND APPROACH

This section:

- Defines the Australian Energy Regulator’s (AER) screening requirements as set out in the documents:
 - AER-Final RIT-D application guidelines-September 2017 (<https://www.aer.gov.au/networkspipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments2017>)
 - National Electricity Rules (NER) Version 117 (<https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current>)
- Describes the approach to assessing the credibility of non-network options.

2.1 DEFINITIONS

Non-network options include (Guidelines Section 7.1):

- Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing)
- 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 – Glossary 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 2.1), an identified need may be addressed by either a network or a non-network 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 2.1).

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 regulatory investment test for distribution, 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 or non-network solution.

Jemena have interpreted the guidance to mean that a credible option could consist of a non-network component and a network component which combined meet the identified need. For example, where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (Application Guidelines Example 4, Section 7.2).

2.2 APPROACH

The approach to assessing the credibility of potential non-network options includes:

- Describing the identified need being addressed by this project 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 network options considered together 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 (defined in Section 3.1)
- Concluding whether there is sufficient and appropriate evidence to determine that there are no non-network options that are potential credible options and identifying any issues that require further examination.

3. IDENTIFIED NEED AND PROJECT OBJECTIVES

Jemena has prepared this non-network screening report to assess whether the demand and safety requirements of the Footscray East Zone Substation could be achieved either fully, or in part through non-network options. To assess whether the non-network options could be beneficial, it is important firstly to define the identified need for this location.

Jemena has identified the Footscray East Zone Substation 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 (Safety); and,
- Secondly, the need 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 condition of major equipment at FE zone substation. This poses a serious risk due to the possibility of failure.

3.1.1 CONDITION OF PLANT

The investment is driven by the deteriorating condition of the switchgear and circuit breakers, which are at risk of failure and pose a serious safety risk.

The two indoor 22 kV metalclad buses and associated circuit breakers manufactured by Metropolitan Vickers type SB14 are estimated to be 81 years old and the switchgear is non-compliant with current arc fault containment standards. The switchgear is showing evidence of decreased insulation resistance and polarisation index from previous testing in 2008. The magnitude of the partial discharge (PD) above the service voltage level has also increased on all phases from the previous measurements in 2008 on the no.1 22 kV bus. The 66 kV bus tie circuit breaker represents a family of breakers with a history of failure. Catastrophic failure of the primary insulation risks the safety of employees and security of customer supply. In 2015 one of its bushings was replaced with a spare due to degradation of the insulation identified during condition monitoring testing. In addition, arcing discharge and surface tracking has been witnessed on the 66 kV brown pin insulators, warranting their replacement.

The potential safety risks of a plant 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 injuries to personnel.
- Risk to public of an extended period of supply interruption.

3.1.2 CREDIBLE SOLUTION REQUIREMENTS

Credible solutions would be required to allow the decommissioning of the existing switchboard 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 which:

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options; and;
- Estimates expected unserved energy 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 asset. Typically, the expected unserved energy is calculated through understanding the load at risk for each substation. This is normally calculated through modelling loads at risk under system and if any single item of equipment was out of service (called a normal minus one or N-1 scenario). A credible non-network solution should maintain a level of supply reliability which is consistent with Regulatory obligations. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply all load under a N and N-1 network reliability scenario in which the annualised cost of expected unserved energy at risk exceeds the cost of augmentation.

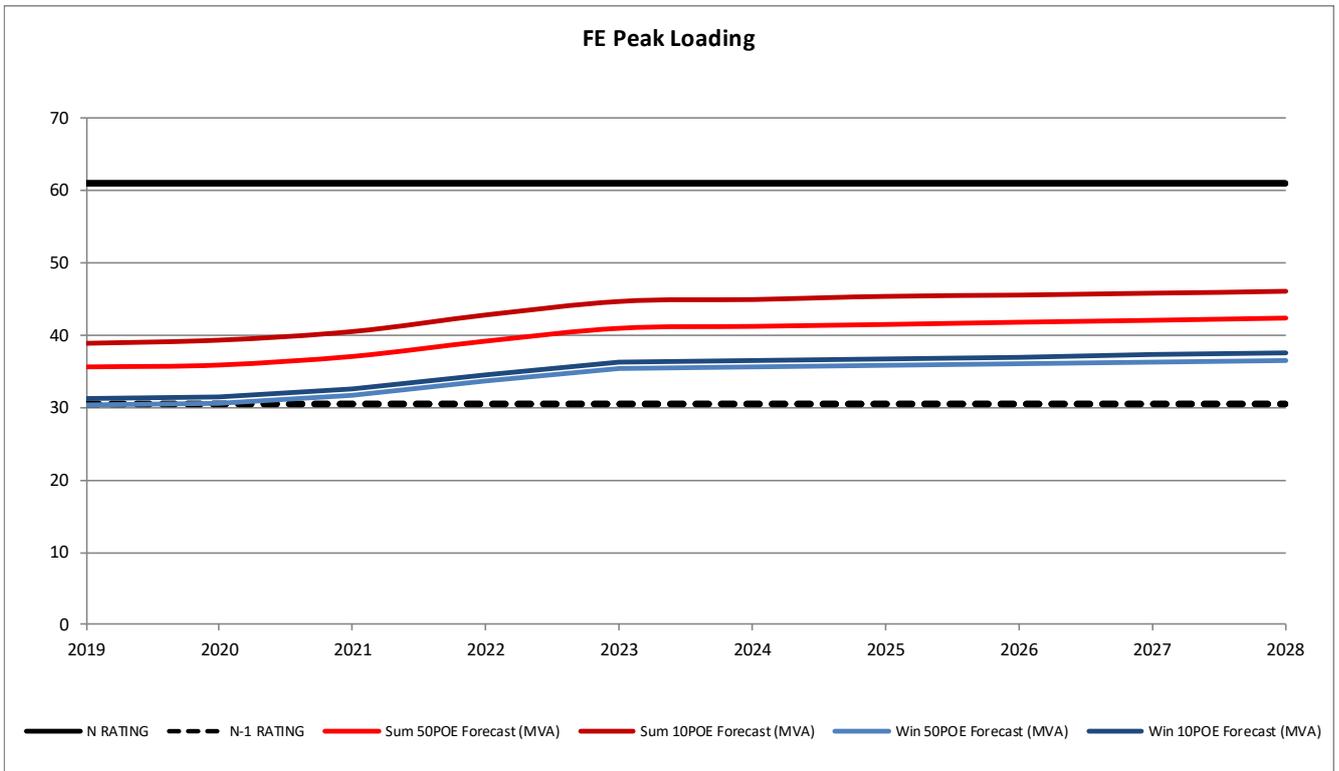
This will depend on the design and capacity of the current network and the forecast load, presented below in Sections 3.2.1 and 3.2.2.

3.2.1 LOAD FORECASTS

The demand forecasts for FE are shown in Figure 3–1. It is noted that the demand is forecast to increase slightly over the period from 2019 to 2028. These forecasts include known spot loads where a customer has made an enquiry or application but do not include potential spot loads that may arise. The load supplied by the substation under 50% PoE summer maximum demand conditions already exceeds the substation's N-1 capacity in summer. Based on the 10% PoE summer maximum demand, outage of a 66/22 kV transformer would result in involuntary load shedding of up to 8.4 MVA in 2019. The 50% PoE winter maximum demand is forecast to exceed the substation's N-1 capacity in 2020.

- The maximum expected demand is 38.9 MVA for summer 2019 under 10% Probability of Exceedance (PoE).
- By 2028, it is forecast that demand will be approximately 46.0 MVA for the summer 10% PoE.

Figure 3–1: FE maximum demand forecast



3.2.2 SUBSTATION CAPACITIES

The station plant items limiting the summer and winter capacity are the 22 kV transformer circuit breakers. Zone substation FE consists of two 66/22 kV power transformers, two 66 kV circuit breakers and has five 22 kV feeders from two indoor switchboards. The ratings of the key assets are:

- One transformer rated 66/22 kV, 20/30 MVA, one transformer rated 66/22 kV, 20/33 MVA transformer
- Each 22 kV bus is rated at 1200 A and consists of space for 5 circuit breakers on each switchboard, of which:
 - 5 are currently used for feeder breakers
 - 1 is used for capacitor banks that can provide 2 x 7.8 MVA_r for power factor correction.

The station has an N rating of 61 MVA. The station N-1 rating is based on a single transformer in service with a rating of 30.5 MVA due to the thermal rating of the existing 22 kV transformer circuit breakers.

3.2.3 CREDIBLE SOLUTION REQUIREMENTS

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. This could be achieved through a range of solutions, including:

- Meeting the identified need in its entirety through a non-network option
- Replacing one switchboard providing 30.5 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 30.5 MVA (maximum forecast varies between 38.9 MVA in 2019 to 46.0 MVA in 2028).

4. NETWORK OPTIONS

The following network options have been considered to manage the risk associated with the aging 22 kV buses and associated switchgear at FE:

- Option 1: Do nothing, run to fail;
- Option 2: Increased maintenance and monitoring;
- Option 3: Full load transfer;
- Option 4: Replace buses and associated switchgear.

The preferred switchgear replacement Option 4 would address all issues at an estimated cost of \$6.37M and would involve replacing the two 22 kV switchboards with a new 22 kV metal enclosed, fully arc contained switchboard, consisting of:

- Two 22 kV 1250 A buses of air insulated type.
- Two 3 phase limb (or 3 x 1 phase per bus) star connected bus VT with a single secondary winding.
- One bus joggle.
- Two 22 kV transformer circuit breakers of 1250 A rating.
- Two 22 kV bus tie circuit breakers of 1250 A rating.
- Eight 22 kV feeder circuit breakers of 630 A rating.
- Two 22 kV capacitor bank panels with integral earth switches.
- One 22 kV spare feeder circuit breaker.
- One 22 kV spare transformer circuit breaker.

Three options have been considered to manage the risk associated with the aging 66 kV CBs at FE:

- Option 1: Do nothing, run to fail;
- Option 2: Increased maintenance and monitoring;
- Option 3: Replace 66 kV CB with SF6 dead tank CB.

Option 3, to replace the existing 66 kV CBs with new modern equivalents at an estimated cost of \$0.35M is the preferred option and will address all the condition issues identified and maintain safety, reliability and security of customer supply. The replacement will consist of:

- Installation of a new outdoor dead tank WMTS-FE No1 66 kV line CB.
- Replacement of the 1-2 66 kV Bus Tie CB with a new 66 kV dead tank CB.
- Replacement of 66 kV hardware.

5. ASSESSMENT OF NON-NETWORK OPTIONS

Potential non-network options that could meet the project objectives (as envisaged in the AER Guidelines Section 7.1) are listed below:

- Demand Management (DM) - Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing)
- Embedded Generation (EG) - 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)

Generation solutions owned by a customer could have cost benefits to that customer and hence be more economic than a generator for the sole purpose of network support.

Potential embedded generation, energy storage or demand reduction solutions are limited by the demand of a 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

Jemena load demand forecasts 2018 report provides information on customer composition and their share of maximum peak load in 2018 estimating that there is a total of 13,932 customers consuming 33.8 MVA peak summer load in 2018 and comprising:

- 12,932 residential customers consuming 22.7 MVA peak summer load (average 0.001755 MVA)
- 1,473 commercial customers consuming 10.8 MVA peak summer load (average 0.007332 MVA)
- 25 industrial customers consuming 0.3 MVA peak summer load (average 0.012 MVA)

For FE, the largest (HV) customers are:

- Customer 1: 2018 Max demand 136 kW
- Customer 2: 2018 Max demand 2.4 MW

Currently there is no HV connected embedded generation supplied from FE zone substation other than the small residential and commercial solar PV. For FE, there are 793 solar installations with a total overall capacity of 3.1 MW.

5.1 CREDIBLE SCENARIOS

The aim is to test whether a non-network option (or combination of non-network measures) is a viable way to avoid or reduce the scale of a network investment in a way that addresses 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).

Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network option
2. Replacing one switchboard providing 30.5 MVA of capacity and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting maximum forecast summer energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). The total requirement from all power sources is in excess of 30.5 MVA (maximum forecast varies between 38.9 MVA in 2019 to 46.0 MVA in 2028).

The non-network screening criteria is applied in the next section with these generation requirements or savings in mind.

5.2 NON-NETWORK ASSESSMENT SCENARIOS

5.2.1 SCENARIO 1 – MEETING IDENTIFIED NEED THROUGH A NON-NETWORK OPTION

A viable non-network generation option that replaces the capacity currently provided by FE that reliably meets customer requirements in an N-1 situation requires:

- Two generators each supplying 40 MVA
- Or three generators each supplying 20 MVA.

This would enable the system to meet maximum demand in an N-1 situation. Adding demand management or efficiency measures to the non-network option would reduce the generation requirements stated above. For example, if management and efficiency reduced peak summer demand to 36 MVA, the non-network generation component could be reduced to two generators of 36 MVA or three generators of 18 MVA each.

The costs of the total replacement scenario are likely to exceed those of the preferred network option. For example, the cost of a 23 MVA gas fired generator is approximately \$15.9M plus installation and operating costs (Source: Gas Turbine World 2017). A non-network option is likely, therefore, to cost over \$40M (e.g. providing 3 generator each costing \$13.8M = \$41.4M plus installation and operating costs). This does not allow for some reduction in peak demand through non-network management and efficiency measures. This would lead to a much higher marginal cost to the customer compared to a network solution of around \$6M for the replacement of 22 kV switchgear and 66 kV CBs.

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 – REPLACING ONE SWITCHBOARD AND RETAINING ONE TRANSFORMER

If only one switchboard were replaced providing the network capacity equivalent to one transformer (30.5 MVA), 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 fail.

A viable non-network generation option that could meet customer requirements in an N-1 situation requires two generators each supplying 20 MVA (assuming no demand management or greater efficiency). This is likely to cost at least \$27M (gas generation of 40 MVA excluding installation and operating costs) (Source: Gas Turbine World 2017).

The requirement for generation could be reduced if coupled with some load transfer to surrounding substations. FE can transfer load to the following surrounding substations: Footscray West (FW), Yarraville (YVE) and Braybrook (BY). FE currently has up to 25.6 MVA of emergency transfer capacity in 2019 reducing the required generation to 14.4 MVA.

5.3 NON-NETWORK ASSESSMENT OPTIONS

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

1. Addresses the identified need: by delivering energy to reduce or eliminate the need for the investment
2. Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
3. Commercially feasible: non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment
4. Timely and can be delivered in a timescale that is consistent with 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	Red
Does not fully meet the criterion (or uncertain)	Yellow
Clearly meets the criterion	Green

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

Table 5–2 shows the initial assessment of non-network options against the RIT-D criteria. The assessment did not find any of the non-network 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	Green	Red	Red	Red
1.2a Generation using renewables (Solar)	Red	Red	Red	Red
1.2b Generation using renewables (Wind)	Red	Red	Red	Red
1.3 Dispatchable generation (large customer)	Red	Yellow	Red	Red
1.4 Large customer energy storage	Red	Yellow	Red	Red
2.0 Demand management				
2.1 Customer power factor correction	Red	Green	Green	Green
2.2 Customer solar power systems	Red	Green	Yellow	Yellow
2.3 Customer energy efficiency	Red	Green	Yellow	Yellow
2.4 Demand response (curtailment of load)	Red	Yellow	Red	Red

5.4 NON-NETWORK ASSESSMENT COMMENTARY

5.4.1 GENERATION AND STORAGE

The assessment commentary for each of the generation and storage options is:

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

Identified need – Reduces safety risks of running old plant beyond life. Capable of meeting identified need through provision of multiple gas generators. **(Fully met)**

Technical – Significant constraints and barriers to deployment of equipment to generate between 14.4 MVA and 40 MVA 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. For example, the minimum scenario of installing a 14.4 MVA gas fired generator at a cost of approximately \$10 million plus installation does not provide any savings compared to installing a second switchboard and requires additional network expenditure in transferring 25.6 MVA to adjacent substations, assuming a minimal feeder works. It is noted that non-network proponents rather than Jemena would bear the cost of these additions and they would recoup these costs through selling power generated at market prices. 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 and any required 22 kV connections to FE) mean this is unlikely to be completed by 2020. **(Not met)**

Overall – Not a potentially credible option.

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

Identified need – Reduces safety risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. There is no information on current solar generation by customers but estimate that the generation of 14.4 MW (the minimum required for a viable non-network option) using solar is likely to require 35 acres of land (<https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1>). Devoting this amount of land to energy production in a dense, urban environment is not feasible. As noted in Section 5 solar installations in FE provide a relatively small capacity of 3.1 MW. In addition, the generation profile of solar power may not align to the consumption profile of consumers. **(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 facility to generate 14.4 MW in this locality. These include zoning, planning and environmental constraints given the land requirements and the lack of evidence of the availability of approximately 35 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. The SolarShare 1 MW solar project in Canberra (<https://solarshare.com.au/solar-farm-project/greenfield-project/>) is costing \$3M and in the Footscray environment purchasing up to 35 acres of land is 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 22 kV connections to FE) mean this is unlikely to be completed by 2020. **(Not met)**

Overall – Not a potentially credible option.

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

Identified need – Reduces safety risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. Based on a 2 MW wind turbine requiring 1.5 acres of land (<https://sciencing.com/much-land-needed-wind-turbines-12304634.html>), a 14.4 MW wind turbine/farm would require 11 acres. Devoting this amount of land to energy production 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, wind conditions for wind generation. 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 unlikely to be allowed. **(Not met)**

Commercial – As for commercial solar generation, the cost of acquiring land and installing wind turbines is likely to significantly exceed the costs of the preferred network solution and means this form of generation is unlikely to be viable. Large scale windfarms are delivering capacity at \$2.5M per MW (<https://reneweconomy.com.au/agls-new-200mw-silverton-wind-farm-to-cost-just-65mwh-94146/>) and this small scale installation is likely to be more expensive in an urban environment. **(Not met)**

Timing – planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 22 kV connections to FE) mean this is unlikely to be completed by 2020. **(Not met)**

Overall – Not a potential credible option.

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

Identified need – Reduces safety risks of running old plant beyond life. There are 25 industrial customers consuming 0.3 MVA at the summer peak (average 0.012 MVA) and 1473 commercial customers consuming 10.8 peak MVA (average 0.007332 MVA). As noted in Section 5 there are only 3 larger industrial (HV) customers with maximum demands of 0.136 MW, 1.2 MW. It's 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 coordinating generation efforts for a large number of small consumers are too great for this to be viable. **(Not met)**

Note: Jemena's 2018 Distribution Annual Planning Report (Section 5.9.4) on customer proposals reports that:

In 2018, Jemena has received only one connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this to be a reflection of:

- *The nature of the JEN network, which services the north east of greater metropolitan Melbourne, where there is limited availability of physical space for a significantly sized embedded generator.*
- *Underlying weaker energy and maximum demand growth in the Victoria region.*
- *A preference for smaller scale embedded generation, particularly roof top solar, for which the JEN network has seen an ongoing increase in installed capacity.*

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 4 MVA to be about \$3.9 million excluding installation and operating costs. This is unlikely to be commercially viable given the much lower costs of providing this capacity using a network solution as well as the unlikelihood of multiple large customers installing a generator of this size. **(Not met)**

Timing – Planning processes, the nature of the investment and likely obstacles, together with design requirements (both for turbines and any required 22 kV connections to FE) mean this is unlikely to be completed by 2020. **(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 in relation to the marginal costs for a full network solution.

Overall – not a potentially credible option

5.4.2 DEMAND MANAGEMENT/EFFICIENCY

The assessment commentary for the demand management/efficiency options is:

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

Identified need – Reduces safety risks of running old plant beyond life. This option is unlikely to meet the identified need because of the absence of very large industrial power users where this type of action could result in significant power savings. **(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 2020. **(Fully met)**

Overall – Not a potentially credible option.

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

Identified need – Reduces safety risks of running old plant beyond life. Solar household installations in Australia is on average 20% and around 15% in Victoria (<https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy>). Satellite imagery suggests that the proportion for the FE catchment is unlikely to exceed this average figure. Approximately 7200 of the 12932 residential customers (56%) would need to have a 2 kW solar system installed to provide 14.4 MW capacity. Currently, as noted in Section 5 solar installations in FE provide a relatively small capacity of 3.1 MW. This rate of take up is not considered to be achievable. **(Not met)**

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

Commercial – Achieving a greater than average solar 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)**

Timing – This option could be completed by 2020 but there is uncertainty given the large number of customers that would need to install solar. **(Not fully met)**

Overall – not a potentially credible option.

- **Customer energy efficiency (2.3)**

Identified need – The assessment for this option is similar to the results for Option 2.2. Each of Jemena's approximately 14,000 customers would have to reduce consumption by approximately 37% for the summer peak to achieve a 14.4 MVA reduction ($14.4 \text{ MVA} / 38.9 \text{ MVA} = 37\%$). This scale of reduction is considered unrealistic even if accompanied by subsidies to consider doing this. **(Not met)**

Technical – This option is technically feasible and the type of efficiencies required achievable if sufficient customers are willing to invest in such measures. **(Fully met)**

Commercial – Unclear that this is commercially feasible. **(Not fully met)**

Timing – This type of mass action would be difficult to promote and implement by 2020. **(Not fully met)**

Overall – not a potentially credible option.

- **Demand response (curtailment of load) (2.4)**

This option has a similar assessment profile to options 1.3 and 1.4. All essentially rely on the actions of a small number of high consumption users. There is no evidence of a small number of very large users who might be persuaded to 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. CONCLUSIONS AND NEXT STEPS

6.1 CONCLUSION

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

In addition, the analysis demonstrates that there are no combinations of non-network options, or non-network and network options, that are likely to adequately meet the criteria that would necessitate the production of a non-network options report.

6.2 NEXT STEPS

Jemena has determined that non-network options are not feasible to meet the identified need. As the preferred network option is less than \$10 million, Jemena does not intend to publish a draft project assessment report per clause 5.17.4(n) of the NER. Furthermore, as the preferred option is less than \$20 million, Jemena will publish its final project assessment report summary as part of its Distribution Annual Planning Report (DAPR).