Jemena Electricity Networks (Vic) Ltd

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

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

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

Authorisation

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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 22kV switchgear and protection relays at Footscray zone substation (FW) is poor. There is an unacceptable risk of failure with significant consequences for staff safety, and the reliability of electricity supply to Jemena customers. The need to remove the asset from service has been demonstrated.

The most urgent concern for Jemena is the evidence of escalating partial discharges from the switchgear, and the threat this poses to staff safety and customer reliability. Removing the aged switchgear from service is a priority task for 2019.

Approach

Jemena has developed a set of potential network solutions to remediate the assets and has investigated whether viable non-network solutions exist. Should viable non-network solutions exist, Jemena is required to publish a non-network options report and request stakeholder submissions.

This report considers the credibility of potential non-network options as alternatives to, or supplements for the FW switchgear and protection relays replacement works.

A non-network option would need to supply the forecast maximum summer load of 45.1 MVA, the forecast 2019 consumer load supplied by FW zone substation. This would allow all of the assets in poor condition to be retired. A non-network solution supplying 30 MVA may be possible if a part of the network is also renewed. Smaller non-network solutions would not provide sufficient capacity to be viable options.

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 the 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.

Error! Reference source not found. shows the rating scale applied for assessing non-network 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	

Error! Reference source not found. shows the initial assessment of non-network 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 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

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 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

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Continuous rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Jemena Electricity Networks (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 winter) 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.
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).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.

ABBREVIATIONS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
FW	Footscray West Zone Substation (66kV/22kV)
JEN	Jemena Electricity Networks
MD	Maximum Demand
NEM	National Electricity Market
POE	Probability of Exceedance
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability

1. BACKGROUND

The condition of the 22kV switchgear and protection relays at Footscray zone substation (FW) is poor. There is an unacceptable risk of failure, with significant consequences for staff safety, and the reliability of electricity supply to Jemena customers. The need to remove the asset from service has been demonstrated. The most urgent concern for Jemena is the evidence of escalating partial discharges from the switchgear and the threat this poses to staff safety and customer reliability. Removing the aged switchgear from service is a priority task for 2019.

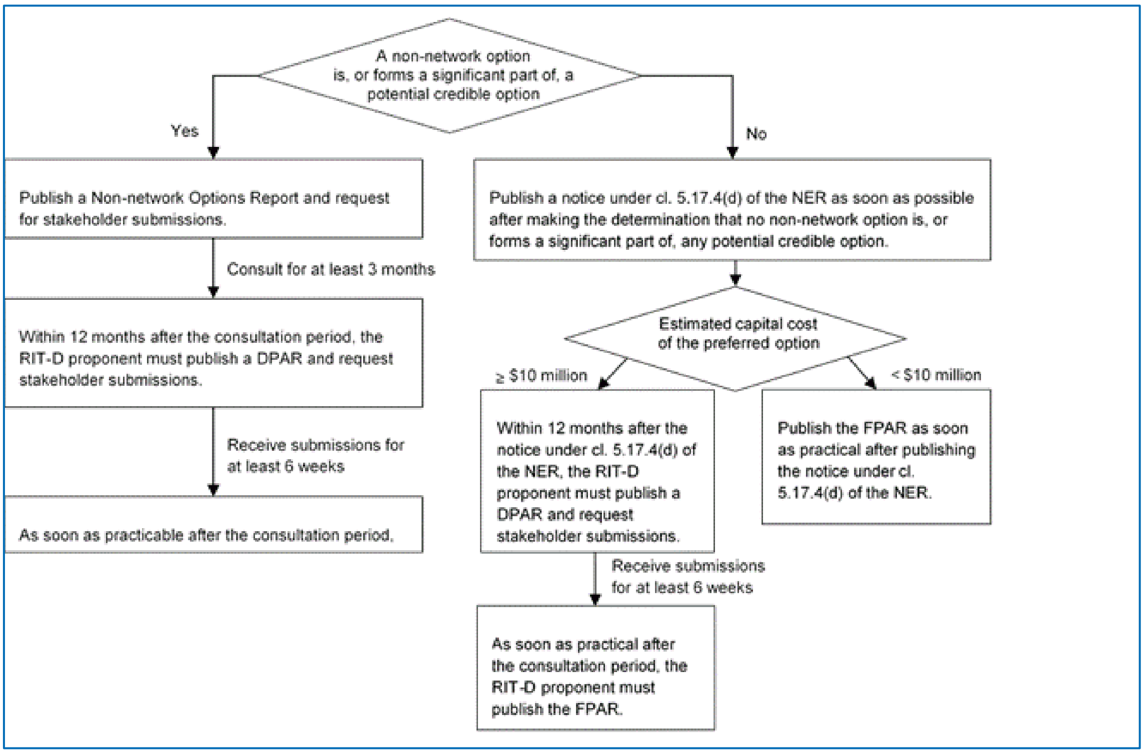
Jemena has developed network solutions to remediate the assets that are in poor condition and to meet the long term demand for electricity in the area.

In November 2017, the Australian Energy Regulator 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 $10M 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 summarized in Figure 1–1: RIT-D process



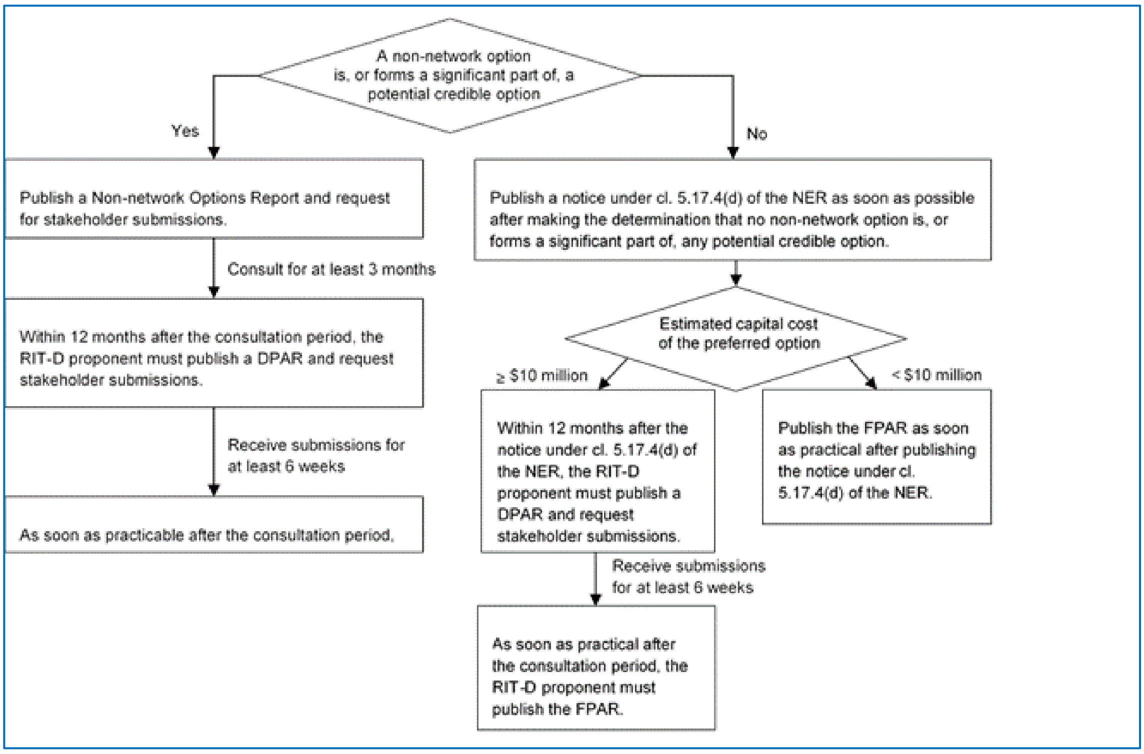
. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- 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/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017)
  - National Electricity Rules (NER) Version 111 (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 on page 1314 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, page 26).

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 West 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 West 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 FW zone substation, This poses a serious safety risk due to the possibility of failure.

3.1.1 CONDITION OF PLANT

This investment is driven by the poor condition of the switchgear and circuit breakers, which are at risk of failure and pose a serious safety risk. The presence of partial discharges mean that the switchgear needs to be replaced as an urgent priority to mitigate significant safety risks to Jemena staff.

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

The April 2015 switchgear and relays replacement business cases (submitted as part of the 2016-2020 EDPR) provide more detail on the age, condition and risks of the equipment to justify the urgent consideration of options for addressing these issues.

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 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 which:

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluation 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 ($/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.

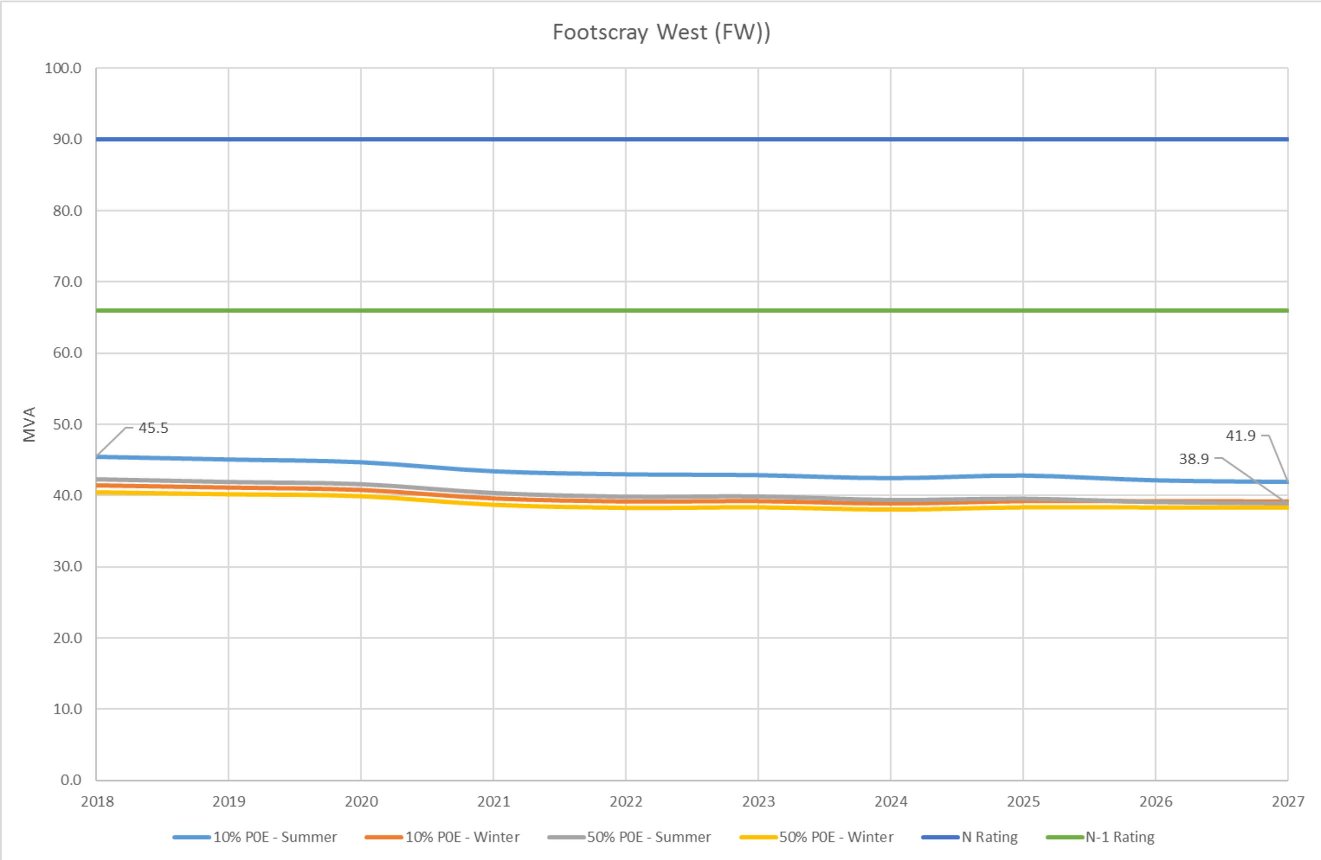
3.2.1 LOAD FORECASTS

The demand forecasts for FW are shown below in Figure 3–1: FW maximum demand forecast

. It is noted that demand is forecast to decline slightly over the period from 2018 to 2027. 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 maximum expected demand is 45.5 MVA for the summer 2018 under 10% Probability of Exceedance (PoE).
- By 2027 it is forecast that demand will be approximately 39 MVA (in most cases) although slightly higher at 42 MVA for the Summer 10% PoE.

Figure 3–1: FW maximum demand forecast



3.2.2 SUBSTATION CAPACITIES

The station plant items limiting summer and winter capacity are the 66/22 kV transformer thermal limits. Zone Substation FW consists of three 66kV/22kV power transformers, two 66kV circuit breakers and has eight 22kV feeders from three indoor switchboards. The ratings of the key assets are:

- Three transformers rated at 30 MVA each, with a cyclic rating of 33 MVA;
- Each 22kV bus is rated at 1,200 Amps and consist of space for 4 circuit breakers on each switchboard, of which:
  - 8 are currently used for feeder circuit breakers
  - 2 are used for capacitor banks that provide 9.14 MVAr and 14.6 MVAr for power factor correction.

The total nameplate rating of the station is 90 MVA. The N-1 rating is based on the transformer cyclic rating of 33 MVA. With two of the three transformers in service, the N-1 rating is 66 MVA.

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 MVA of capacity and meeting the remaining capacity through a non-network option
- Replacing two switchboards, each providing 30 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 45 MVA (maximum forecast varies between 45.5 MVA in 2018 to 41.9 MVA in 2027).

4. NETWORK OPTIONS

4.1 2015 SWITCHGEAR AND RELAYS BUSINESS CASES

The April 2015 switchgear business case submitted to the AER as part of EDPR 2016-2020 considered the following options:

- Option 1-Do Nothing: running the switchgear to failure
- Option 2-Maintenance: as for Option 1 but with more intensive maintenance
- Option 3-Refurbishment: addressing some problems through the refurbishment of equipment
- Option 4-Load transfer: involving the transfer of all load from FW and the temporary or permanent retirement of the substation
- Option 5-Replace switchgear: this is seen as the preferred option in terms of adequately addressing the full range of problems and risks
- Option 6-Staged replacement: Seen as partly addressing the identified problems and risks.

The preferred switchgear replacement Option 5 would start in 2019 and be completed in 2020 at a total cost of $5.6M ($2014 real) replacing:

- Three 22kv buses
- Two bus tie circuit breakers
- No. 3 transformer enclosure roof
- As part of this work, all protection schemes associated with 22kV and 66kV bus and circuit breaker protections.

The April 2015 relays business case submitted to the AER as part of EDPR 2016-2020 considered the following options:

- Option A1-Do Nothing: running the relays to failure and then like for like replacement with business as usual maintenance
- Option A2-Similar to Option A1 but replace failed relays with new relays that will required additional detailed design
- Option B-Increased routine maintenance and testing to reduce the likelihood of a relay failure
- Option C-Planned replacement of Transformer and Capacitor Bank protection relays and the DC supply system
- Option D-Planned replacement of all secondary equipment at FW.

The preferred switchgear Option D replacing all secondary equipment would start in 2019 and be completed in 2020 at a total cost of $4.9M ($2014 real) replacing:

- X & Y Transformer Protection Relays;
- No.1 & No.3 Capacitor Bank Protection & Control Relays;

- DC Supply Systems;
- Feeder Management Relays; and
- Backup Earth Fault and Master Earth Fault Relays.

4.2 LATEST JEMENA REVIEW

In July 2018 Jemena undertook an analysis of the following options for completing the switchgear and secondary equipment replacement task. This review confirmed Option 4 - Replace three switchboards at FW and operate with three transformers with cost estimate of approximately $9.8M as the preferred network option. The other options could potentially allow a non-network proponent to offer a partial solution (this possibility is explored further in Section 6.2).

- Option 1-Do Nothing: running assets till they fail
- Option 2-Replace two switchboards and secondary plant at FW (use two transformers) and transfer 15 MVA from FW to TH (requires additional feeder works)
- Option 3-Replace two switchboards and secondary plant at FW (use two transformers) with no feeder augmentation and availability of one cold transformer
- Option 4-Replace three switchboards and secondary plant at FW and operate with three transformers.

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 2017 report provides information on customer composition and their share of maximum peak load in 2017 estimating that there is a total of 14,094 customers consuming 42.4MVA peak summer load in 2017 and comprising:

- 13,275 residential customers consuming 18.062 MVA peak summer load (average 0.0014 MVA)
- 789 commercial customers consuming 8.014 MVA of peak summer load (average 0.0102 MVA)
- 30 industrial customers consuming 16.324 MVA of peak summer load (average of 0.5441 MVA).

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

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

Currently there is no HV connected embedded generation supplied from FW zone substation other than the small residential and commercial solar PV. For FW, there are 576 solar installations with a capacity of 1.51 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 MVA of capacity and meeting the remaining capacity through a non-network option
3. Replacing two switchboards, each providing 30 MVA of capacity and meeting the remaining capacity through a non-network option.
4. 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 45 MVA (maximum forecast varies between 45.5 MVA in 2018 to 41.8 MVA in 2027).

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 FW that reliably meets customer requirements in an N-1 situation requires:

- Either, two generators each supplying 45 MVA
- Or three generators each supplying 23 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 42 MVA the non-network generation component could be reduced to two generators of 42 MVA or three generators of 21 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 $50M (e.g. providing 3 generator each costing $15.9M = $48M 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 $10M for the replacement of all three switchboards 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 – REPLACING ONE SWITCHBOARD AND RETAINING ONE TRANSFORMER

If only one switchboard and related protection relay assets were replaced providing the network capacity equivalent to one transformer (30 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 23 MVA (assuming no demand management or greater efficiency). This is likely to cost at least $32M (gas generation of 46 MVA excluding installation and operating costs) (Source: Gas Turbine World 2017).

5.2.3 SCENARIO 3 – INSTALLING TWO SWITCHBOARDS, EACH OF 30 MVA CAPACITY (WITH AND WITHOUT TRANSFERS)

The most realistic scenarios 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, we considered the potential credibility of non-network options for covering the gap when only two switchboards are replaced at FW so it has a new configuration of two switchboards and two transformers with a capacity of 60 MVA and N-1 capacity of 33 MVA. With this reduced investment (and no permanent load transfers) a non-network option would need to cover for the failure of a transformer or one of the switchboards which would leave a shortfall of maximum required load in 2018 of 12.4 MVA (45.4 MVA – 33 MVA – the cyclic rating of the remaining transformer). By 2019 this shortfall is expected to be 12.0 MVA and by 2020, 11.6 MVA.

The cost of providing this scale of generation is likely to be in the order of $10M plus installation and operation costs (Source: Gas Turbine World 2017).

The required output of a non-network solution might be further reduced if the renewal of two switchboards was coupled with some load transfer to surrounding substations. In this situation, non-network options might need to deliver half the required load (e.g. 6 MVA) with load transfers covering the remainder. The non-network generation cost is likely to be in the order of $7M for gas generation and $5.5M for diesel generation plus installation and operating costs (Source: Gas Turbine World 2017).

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:

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: Assessment criteria rating

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 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: Assessment of non-network options against RIT-D criteria

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 insolation, and in combination with network solutions). The assessment commentary for each of the generation and storage options is set out in the following sections.

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

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 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 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

5.4 NON-NETWORK ASSESSMENT COMMENTARY

5.4.1 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 (Met).

Technical - Significant constraints and barriers to deployment of equipment to generate between 6 MVA and 45 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 6 MVA gas fired generator at a cost of approximately $5.6M plus installation compares to a saving of just over $1M from not installing a third bus at FW and requires additional network expenditure of $0.2M in transferring 6 MVA of load to adjacent substations, assuming minimal feeder works (not met). 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 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 22kV connections to FW) 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 6 MW (the minimum required for a viable non-network option) using solar is likely to require 15 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 6 solar installations in FW provide a relatively small capacity of 1.51 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 6 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 15 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 1MW solar project in Canberra (https://solarshare.com.au/solar-farm-project/greenfield-project/) is costing $3M and in the Footscray environment purchasing up to 15 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 22kv connections to FW) 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 6 MW wind turbine would require 4.5 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 (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 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 $2.25M 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—The requirement to coordinate the installation of generation across a relatively large number of industrial power consumers together with likely planning requirements mean it is uncertain that a 2020 completion date could be achieved (not fully met).

Overall—not a potentially credible option.

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

Identified need—Reduces safety risks of running old plant beyond life. There are 30 industrial customers consuming 16.324 MVA at the summer peak (average 0.5441 MVA) and 789 commercial customers consuming 8.104 peak MVA (average 0.0102 MVA). As noted in Section 6 there are only two larger industrial (HV) customers with maximum demands of 1.7 MVA and 1.4 MVA. 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.

Note: Jemena's 2017 Distribution Annual Planning Report (Section 5.10.4) on customer proposals reports that:

> *In 2017, Jemena has not received any 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 $3.9M and 6.5 MVA about $5.6M both 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.

Timing—Planning processes, the nature of the investment and likely obstacles, together with design requirements (both for turbines and any required 22kV connections to FW) 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 penetration in Australia is on average 16%. Satellite imagery suggests that the proportion for the FW catchment is unlikely to exceed this average figure. Approximately 850 of the 1,362 residential customers (62%) would need to have a 2kw solar system installed to provide 6 MW capacity (based on generation of 7.2 kWh per day - https://www.solarchoice.net.au/blog/how-much-energy-will-my-solar-cells-produce/). Currently, as noted in Section 6 solar installations in FW provide a relatively small capacity of 1.51 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 13% for the summer peak to achieve a 6 MVA reduction (6 MVA/45.4 MVA = 13.2%). 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. CONCLUSION 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 will prepare a Draft Project Assessment Report (DPAR) which will present a detailed assessment of all network options to address the identified need. The DPAR will apply the latest available information on demand forecasts, VCR estimates and project cost estimates.

We intend to publish the DPAR by 31 October 2018. Further consultation, in accordance with the RIT-D process set out in the Rules, will then procced.