Jemena Electricity Networks (Vic) Ltd

East Preston (EP) Conversion Stage 5

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

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Name	Job Title	Date	Signature
Reviewed by:			
Alan Shu	Network Capacity Planning and Assessment Manager (Acting)	20/09/2018	
Approved by:			
Johan Esterhuizen	General Manager Asset Strategy Electrical	20/09/2018	

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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
CN	Coburg North Zone Substation
CS	Coburg South Zone Substation
EP	East Preston Zone Substation (66kV/6.6kV)
EPN	East Preston Zone Substation (66kV/22kV)
JEN	Jemena Electricity Networks
MD	Maximum Demand
NEM	National Electricity Market
P	Preston Zone Substation (66kV/6.6kV)
POE	Probability of Exceedance
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability

OVERVIEW

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**).

1.1 IDENTIFIED NEED

The Preston distribution network has operated since the 1920s with a primary voltage level of 6.6kV from two 66/6.6kV Zone Substations, Preston (P), and Preston East (EP). The surrounding substations at Coburg North (CN), Coburg South (CS) and North Heidelberg (NH) all operate at 22kV.

The assets at both P and EP zone substations were mostly installed in the 1960s, although some elements are significantly older. At both zone substations there were safety concerns both for staff health and safety, and for the public due to the aging and poor condition of the plant being run at increasing demand levels.

In addition, the difference in voltage levels made it challenging to react quickly in times of peak demand (unplanned feeder outage) to transfer load from adjacent zone substations. Additionally, distribution at 6.6kV has higher electrical losses compared to distribution at higher voltages and therefore, more feeders are required. This results in congestion in the streets and utilization of all easements. There was minimal capacity to increase the number of feeders in response to the forecast demand increases in the area – any new 6.6kV feeders would have had to be undergrounded. This restricted the supply options, and increased cost of connection for new development proposals. There was also concern around the resilience of the network in the event of pole damage as several poles support up to three high voltage feeder circuits.

1.2 APPROACH

Jemena has developed a network strategy called Preston Area Conversion 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. Given the staging of the works in the Preston area, the currently proposed works could be changed in scope or otherwise altered in response to a non-network solution. Hence Jemena has undertaken to investigate 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 or supplements for the EP substation replacement works.

A non-network option would need to supply 31.2 MVA, the forecast consumer load supplied from EP zone substation. This would allow all of the assets in poor condition to be retired. A non-network solution supplying

15.3 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.

1.3 SUMMARY OF FINDINGS

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

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

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

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

Figure 1: Criteria Rating

Figure 2 shows the initial assessment of non-network options against the RIT-D criteria.

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 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)				

Figure 2: Assessment of non-network options against RIT-D criteria

The conclusion is 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 5.17.4(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.

2. BACKGROUND

The Preston distribution network has operated since the 1920s with a primary voltage level of 6.6kV from two 66/6.6kV Zone Substations, Preston (P), and Preston East (EP). The surrounding substations at Coburg North (CN), Coburg South (CS) and North Heidelberg (NH) all operate at 22kV.

The assets at both P and EP zone substations were mostly installed in the 1960s, although some elements are significantly older. At both zone substations there were safety concerns both for staff health and safety, and for the public due to the aging and poor condition of the plant being run at increasing demand levels. JEN undertook Condition Based Risk Management modelling to rank the replacement of high risk plant items, and this prioritized the decommissioning of the P zone substation (which was completed mid this year) followed by the decommissioning of the EP zone substation (noting that EP consists of two switch-houses, EP 'A' and EP 'B').

In addition, the difference in voltage levels made it challenging to react quickly in times of peak demand (unplanned feeder outage) to transfer load from other substations. Additionally, distribution at 6.6kV has higher electrical losses compared to distribution at higher voltages and therefore, more feeders are required. This results in congestion in the streets and utilization of all easements. There was minimal capacity to increase the number of feeders in response to the forecast demand increases in the area – any new 6.6kV feeders would have had to be undergrounded. This restricted the supply options, and increased cost of connection for new development proposals. There was also concern around the resilience of the network in the event of pole damage as several poles support up to three high voltage feeder circuits.

To allow the P zone substation to be decommissioned it was first necessary to transfer as much load as possible away to other substations. This work began in 2008, and means that nearby substations CN and CS are currently operating under higher levels of load than optimal. In November 2015 a new 66kV/22kV (single transformer) zone substation was completed on the East Preston site (the EPN substation).

In December 2017 all the remaining P feeders were transferred away from the old P zone substation allowing the decommissioning process to begin and a new 66kV/22kV (two transformer) substation (Preston (PTN)) to be constructed (completion date expected by end of November 2019).

Once this stage is complete the nearby substations CN and CS will be restored to sustainable operating levels. The new PTN zone substation will provide improved 22kV voltage transfer capability, and leave EP 'A' and EP 'B' as two of the last three remaining 6.6kV substations in Jemena's network, supporting the residual 6.6kV asset in the East Preston area (approximately 4,700 consumers).

Jemena has developed these 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 $5 million. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need.

Given the staging of the works in the Preston area, the currently proposed works could be changed in scope or otherwise altered in response to a non-network solution. Hence Jemena 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.

2.1 RIT-D PROCESS

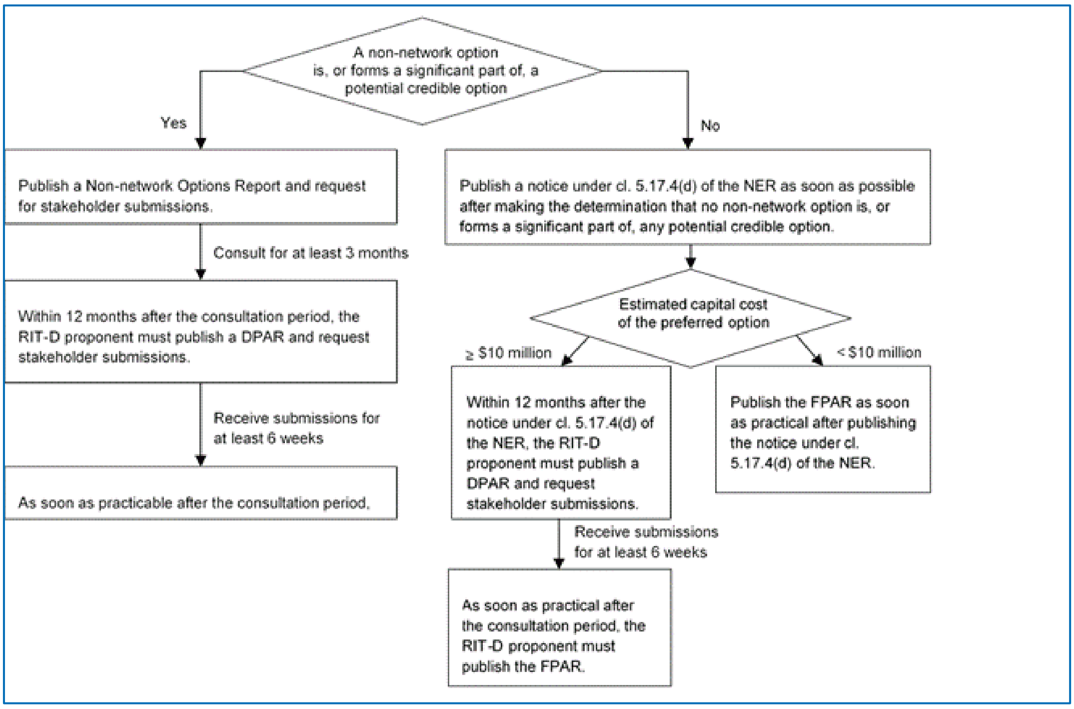
The RIT-D process is summarized in Figure 1. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- 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 3)
- describes the Identified Need the project is aiming to address (Section 4)
- describes the network options tested to date (Section 5)
- assesses the potential of non-network options to help address the identified need (Section 6)
- states the conclusion on the need for a non-network options report (Section 7).

Figure 1 RIT-D Process



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

3. 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.

3.1 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).

3.2 APPROACH

Jemena's 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 the 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.

4. IDENTIFIED NEED AND PROJECT OBJECTIVES

Jemena has commissioned this non-network screening report to assess whether the demand and safety requirements of the Preston network 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 Preston distribution network as a priority for investment based on three key needs:

- Firstly, the need to protect power sector workers and members of the public from harm caused by equipment failure (Safety);
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network now (Reliability); and,
- Thirdly, the need to support growth aspirations for the Preston area through reducing cost and complexity of connection for new residences and new businesses (Growth in the Preston Area).

When the RIT-D process was introduced in November 2017, works to address the assets in poor condition in the Preston area had commenced. The works are structured in stages some of which are linked and must be completed before further work can be reassessed for prudency and changed if necessary. Such a point will be reached in November 2019 when the currently committed works are complete, which includes the establishment of new zone substation PTN and the decommissioning of substation P. The further stages are set out in the next chapter. This non-network screening report is based on the network that will exist in November 2019 and the needs identified for that network.

4.1 SAFETY

The ability to provide a safe network is limited by the poor condition of major equipment at EP zone substation, which is at risk of failure and poses serious safety and supply reliability risks.

4.1.1 CONDITION OF PLANT

Failure of equipment at EP would lead to widespread interruptions to customers for an extended period of time and poses significant health and safety risks to any personnel working in the vicinity since the switchboards are non-arc-fault contained. The situation will worsen as the assets further deteriorate and customer demand grows.

Problems of deterioration of supply reliability due to capacity shortfall, lack of transfer capability and steady load growth will result in load shedding during times of peak demand under single contingency conditions.

Although established in the 1920s, EP substation underwent extensive refurbishment in the early 1960s, therefore the average year of installation of the major equipment, including transformers indoor and outdoor circuit breakers and buses, is 1964. From JEN’s Asset Class Strategies and with the application of JEN’s Condition Based Risk Management modelling using inputs from condition testing and monitoring, the major equipment (primarily the circuit breakers and buses) at EP are assessed to be at a ‘high’ risk of failure.

The potential safety risks of a plant failure are listed below:

- Severe injury or death to JEN’s operating personnel and the general public in the vicinity of the substation.
- Risk of step and touch potentials causing injuries to personnel.

- Risk of extended period of supply interruption due to blown-up switchgear.
- Adverse brand and reputation ramification.

The deteriorated condition of the assets and detail discussions on the need to retire and replace the major primary assets at P and EP Zone Substations are documented in the following JEN reports:

- JEN PL 0039 Circuit Breakers Asset Class Strategy
- JEN PL 0042 Transformers Asset Class Strategy

It is also expected that over the next 10 years there will be an increase in maintenance costs for repair and condition monitoring at EP zone substation as the assets reach end of life. Further details on the deteriorated condition of secondary assets are documented in JEN Zone Substation Protection & Control Equipment Asset Class Strategy (document number JEN PL 0021).

4.1.2 CREDIBLE SOLUTION REQUIREMENTS

Credible solutions would be required to allow the decommissioning of the major primary assets at EP ‘A’ and EP ‘B’, including transformers, switchgear and secondary equipment.

4.2 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, which are presented below.

4.2.1 LOAD FORECASTS

The demand forecasts for EP ‘A’ and EP ‘B’ are shown below in Figure 3 and Figure 4. The forecasts for the supply area show that the maximum expected demand for EP ‘A’ is 15.9 MVA and for EP ‘B’ is 15.3 MVA for the summer 10% PoE in 2020. The forecast demand is effectively flat (no growth) between 2019 and 2026. 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, as these are likely to exceed the capacity of the 6.6kV system and hence are likely to be supplied from the more remote 22kV system (discussed further in Section 4.3).

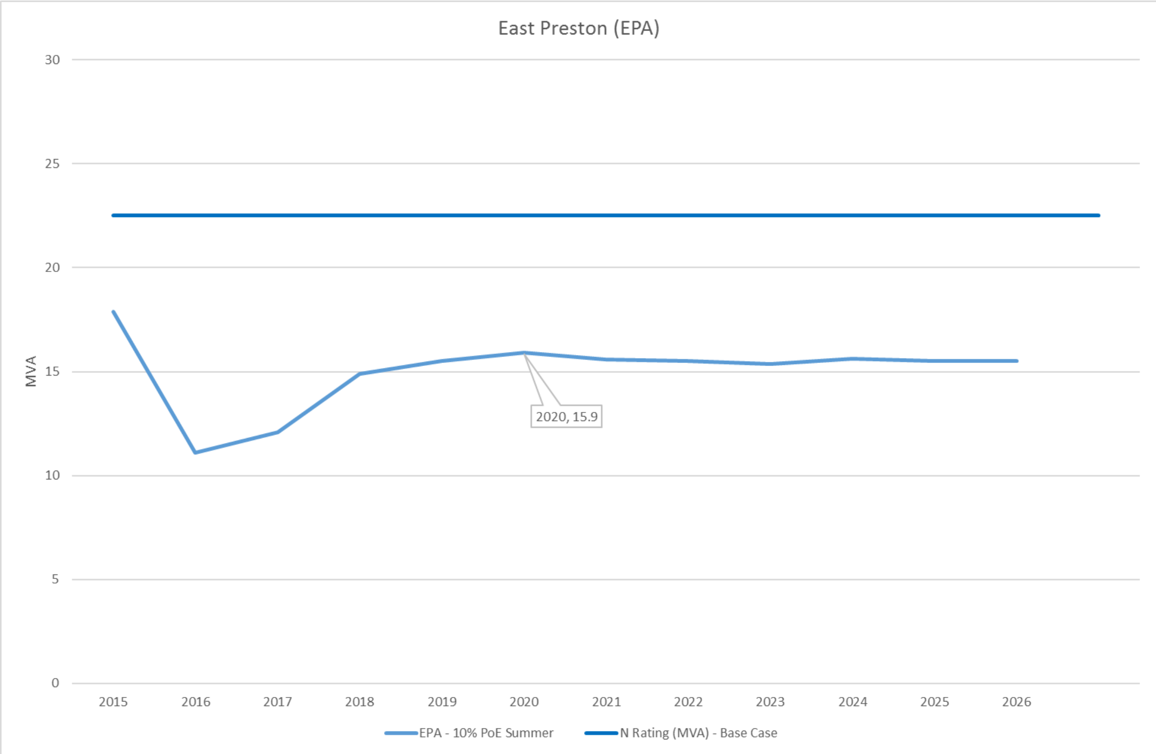


Figure 3: EP ‘A’ Demand Forecasts (10% PoE Summer MVA)

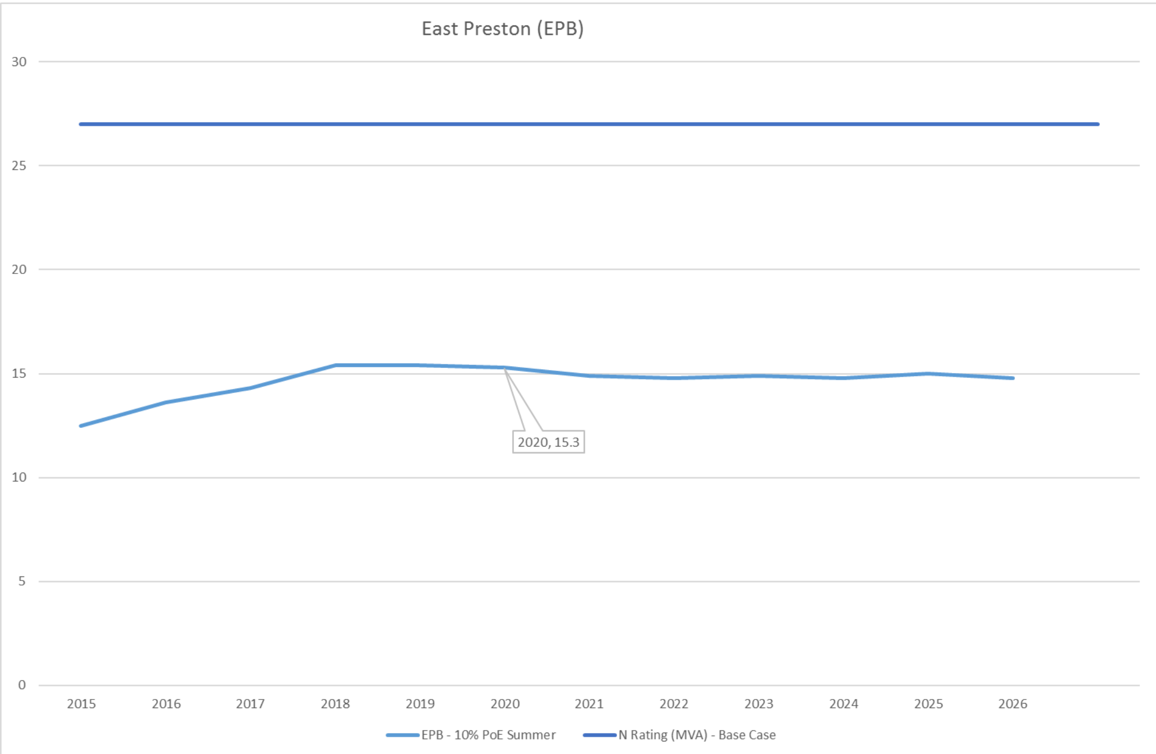


Figure 4: EP ‘B’ Demand Forecasts (10% PoE Summer MVA)

Note that the contribution of Solar energy generation within the Preston Area was 1.3 MW in 2018, derived from 470 installations. This contribution is not expected to change such that it would impact the minimum capacity required of a non-network solution.

4.2.2 SUBSTATION CAPACITIES

The station plant items limiting summer and winter capacity is the 66/6.6 kV transformer thermal limits. Both EP ‘A’ and EP ‘B’ are operated with an auto-close bus-tie circuit breaker which will close in the event of a transformer outage, which gives them a higher N-1 substation rating.

The capacities of assets (as modelled post completion of P Stage 6 in November 2019) are set out below.

Based on the preferred staging of works, the overall capacities offered across the Preston area are summarized below in Table 1.

Table 1: Preston Area Capacity (for preferred staging of works) for preferred network option

Zone Substation	Stage (planned in service date)			
	EP Stage 5 (Nov’ 2020)	EP Stage 6 (Nov’ 2021)	EP Stage 7 (Nov’ 2022)	EP Stage 8 (June 2023)
EP ‘A’	N Rating = 22.5 MVA N-1 cyclic Rating = 22.5 MVA Load transfer capacity = 2MVA	Decommissioned	Decommissioned	Decommissioned
EP ‘B’	N Rating = 27 MVA N-1 Cyclic Rating =28.5 MVA Load Transfer Capacity = 3 MVA	N Rating = 27 MVA N-1 Cyclic Rating = 28.5 MVA Load Transfer Capacity = 0 MVA	N Rating = 27 MVA N-1 Cyclic Rating = 28.5 MVA Load Transfer Capacity = 0 MVA	Decommissioned
PTN	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Cyclic Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA
EPN	N Rating = 33 MVA N-1 cyclic Rating = 0 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA

4.2.3 CREDIBLE SOLUTION REQUIREMENTS

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. Table 2 shows the forecast load required to be supplied and to assist in developing project staging, possible staging scenarios with the current network contributions, the forecast load and the gap that would form the minimum load for a credible solution.

Table 2: Credible Solution Capacity Requirements (2020)

SCENARIO	FORECAST LOAD (MVA)	CURRENT NETWORK CONTRIBUTION (MVA)	CREDIBLE SOLUTION CONTRIBUTION (MVA)
Decommissioning of EP ‘A’ and EP ‘B’	31.2	0	31.2
Scenario - Decommissioning of EP ‘A’ transformer and associated equipment	EP ‘A’: 15.9 EP ‘B’: 15.3 Total: 31.2	EP ‘A’: 0 EP ‘B’: 15.3+3=18.3 Total: 18.3	12.9
Scenario - Decommissioning of EP ‘B’ transformer or associated equipment	EP ‘A’: 15.9 EP ‘B’: 15.3 Total: 31.2	EP ‘A’: 15.9+2=17.9 EP ‘B’: 0 Total: 17.9	13.3

Note: Network contribution assumes load transfers are available between EP ‘A’ and EP ‘B’ at current levels

At present, if EP ‘A’ was to fail, EP ‘B’ 6.6kV feeders has up to 3 MVA load transfer capacity, and if EP ‘B’ was to fail, EP ‘A’ 6.6kV feeders would be able to handle up to 2 MVA of load. Hence if load transfers are included in the assessment, the load at risk at the time of maximum demand would be 12.9 MVA for EP ‘A’, and 13.3 MVA for EP ‘B’. This arrangement assumes that the nearby substations CN and CS can continue operating under higher levels of load than optimal until some load can be transferred to new zone substation PTN (due for completion in November 2019). For the purposes of this assessment, this matter is ignored.

4.3 GROWTH IN THE PRESTON AREA

The need to provide for growth is fundamental to meeting Jemena’s distribution licence requirement to make an offer to connect consumers. Credible options should consider the ability to meet reasonable predictions for growth in the Preston area. Note that the volume of potential growth and size of spot loads compared to the capability of current feeders would likely require extensive modification of current assets to increase their capacity or bypassing of the 6.6kV system and connection to the more remote 22kV system.

4.3.1 POTENTIAL GROWTH

Darebin City council has developed a Preston Central Structure Plan which will see significant expansion of Northland and the surrounding areas in future years.

Darebin Council also plans to develop two strategic corridors in the Preston areas, one along Plenty Road and the other along St. Georges Road. In particular, Plenty Road is slated for a much-needed increase in residential density with more apartment-style housing, mixed use and taller buildings in select locations. One such development in this area includes a recent planning application between High Street and Plenty Road for a new 18 level, 60 m tall, mixed use tower which is expected to deliver over 220 apartments. In addition, Darebin City Council has a strategy and plan to facilitate urban growth in the Oakover Village Precinct around the Preston area to a mixed use consisting of high-rise residential, commercial and retail developments. The estimated total maximum demand over the next 10 years is 12MVA.

Salta Properties have begun the redevelopment of Preston Market as part of a new $750 million residential and retail complex. It is expected the development will expand and connect to the Preston railway station. This redevelopment will include residential, retail, traditional market and modern shopping facilities.

With the available infrastructure, the new loads will be difficult and costly to supply at the 6.6 kV voltage level. Additional new feeders will be difficult to establish, and if physically possible, will be at a significantly higher cost due to congestion in the surrounding areas as well as other assets in the ground for which adequate clearances must be maintained. As JEN is under a legal obligation (Distribution Licence) to make offers to connect customers and if those offers are accepted then, it may be necessary to install long runs of 22 kV rated underground cables from a neighbouring zone substation through the 6.6 kV supply area to supply new large customers.

4.3.2 CREDIBLE SOLUTION REQUIREMENTS

Credible solutions would be required to be scalable to meet future load growth needs.

5. NETWORK OPTIONS

As previously noted in this report, the works to address the needs in the Preston area have already commenced. Works competed to date are shown in Table 3. P Stage 6 is committed and currently in progress for an in-service date of November 2019.

Table 3: Preston Area Network Programme

Stage(s)	In service date	Completed works
P Stage 1	Nov 2008	Conversion of P feeders and distribution substations
EP Stage 1 & 2	Nov 2008	Conversion of EP feeders and distribution substations
P Stage 2	Nov 2009	Conversion of P feeders and distribution substations
P Stage 3	Dec 2012	Conversion of P feeders and distribution substations
EP Stage 3	Nov 2015	New 66/22kV single transformer EPN zone substation
P & EP Stage 4	Nov 2016	Conversion of P & EP feeders and distribution substations
P Stage 5	Sept 2017	Conversion of remaining P feeders and distribution substations
P Stage 6	November 2019	Decommission P zone substation & establish new 66/22kV two transformers PTN zone substation

Prior to committing to the next stage to establish a new zone substation (PTN), a review was undertaken that resulted in a 2017 business case that confirmed the plan and staging of the required works. The business case considered the following options:

Option 1- Do Nothing - Stopping the Preston Conversion Programme at the end of P Stage 6 and running the remaining 6.6 kV network to failure

Option 2- Continue the Preston Conversion Programme

Option 3 – Delay Preston Conversion Programme through utilizing spare capacity at Fairfield zone substation (and installing additional 6.6kV network capacity)

The preferred option was to continue the Preston Conversion Programme as described below in Table 4.

Table 4: Preferred Network Solution (Staged)

Stage(s)	In service date	Cost estimate	Anticipated works
EP Stage 5	November 2020	$6.3M	Conversion of EP ‘A’ feeders and distribution substations
EP Stage 6	November 2021	$9.0M	Decommission of EP ‘A’ zone substation and install 2nd transformer at EPN zone substation
EP Stage 7	November 2022	$11.8M	Conversion of EP ‘B’ feeders and distribution substations
EP Stage 8	June 2023	$4.5M	Conversion of EP ‘B’ feeders and distribution substations. Decommission of EP ‘B’ Substation.
TOTAL		$31.6M	

6. 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. The 2017 breakdown of customers in Preston is shown below in Table 5.

Table 5: 2017 Preston Customer Breakdown

Customer Type	East Preston 'A'	East Preston 'B'	East Preston (EPN)	Total
Residential	688	3,501	4,181	8,370
Commercial	247	243	469	959
Industrial	7	6	12	25
Total	942	3,750	4,662	9,354

The updated figures (July 2018) for each substation are shown below in Table 6.

Table 6: 2018 Preston Customer Breakdown

Customer Type	East Preston 'A'	East Preston 'B'	East Preston (EPN)	Total
All customers	831	3,912	6,084	10,827

Note: On completion of P Stage 5 approximately 1,500 customers were transferred from P to EPN.

The forecast customer numbers for 2020 for each substation are shown below in Table 7.

Table 7: 2020 Forecast Preston Customer Breakdown

Customer Type	East Preston (EPN)	Preston (PTN)	Total
All customers	2,255	13,109	15,364

The largest industrial customers at the EP zone substation are provided below (names removed for commercially confidentiality):

HV customers (6.6kV):

- Customer One (MD is about 500 kVA) and Customer Two (700 kVA).

LV customers (433V):

- Customer Three (1 MVA), Customer Four (600 kVA), Customer Five (1 MVA) and Customer Six (1 MVA).

The EP zone substation does not have any HV connected embedded generation.

6.1 CREDIBLE SCENARIOS

The NER requires proponents to investigate whether a non-network option (or combination of non-network measures) is capable of avoiding the need for investment in a network solution or at least allows a smaller network investment to meet the identified need.

Potential non-network scenarios are:

1. Meeting the identified need in its entirety through a non-network solution
2. Installing some network assets and meeting the remaining capacity through a non-network solution.

Scenario 1

Meeting the identified need in its entirety through a non-network solution would require measures capable of meeting maximum forecast summer energy requirements (31.2 MVA) with a level of redundancy to cover this need when the largest single source of power fails.

Scenario 2

The most realistic scenarios for non-network options making a potentially credible contribution to the project's objectives are where they allow for a reduced level of investment below the preferred network solution.

Consistent with the National Electricity Objective (NEO) to maintain a safe and reliable supply to customers, a network solution ultimately requires zone substation EPN to have a minimum of two transformers. The timing of the second transformer (2021) is currently set to allow the conversion of the EP 'B' feeders to 22kV (2022) and the subsequent decommissioning of the EP 'B' substation. The installation of the second transformer could be avoided by a non-network solution that matched the difference between the current capacity of the system when operating under a N-1 condition (0 MVA) and the forecast load. This value is approximately the load currently supplied by EP 'B' (15.3 MVA). The non-network screening criteria is applied in the next section with these generation requirements or savings in mind.

6.2 NON-NETWORK ASSESSMENT OVERVIEW

This section reports on the credibility of potential non-network options as alternatives or supplements for the East Preston substation 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.

Figure 5 shows the rating scale applied for assessing non-network options.

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

Figure 5: Assessment Rating Criteria

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).

Figure 6 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.

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 options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

Figure 6: Assessment of non-network options against RIT-D criteria

6.3 NON-NETWORK ASSESSMENT COMMENTARY

6.3.1 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. Fails to reduce cost and complexity of connection for new developments (partially met).

Technical—Significant constraints and barriers to deployment of equipment to generate a minimum of 31.2 MVA in a dense urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). In addition, Jemena cannot establish the availability of a suitable high pressure gas pipeline in the locality that is essential for this type of generation (not met). Further, the solution would be dependent on a single fuel source, gas. Multiple high pressure gas sources are not available in the area, meaning that a gas turbine solution could not maintain a safe and reliable supply to customers (not met). Due to the 6.6kV fault level limitations at EP zone substation, buses EP ‘A’ and EP ‘B’ were separated. Installing generators would result in an increase in fault levels which could exceed Code Limits under N and N-1 conditions (not met).

Commercial—Costs of this type of generation appear much higher than the network alternatives. Gas fired generators would cost approximately $9.8 million each for a minimum capacity of 15.3 MVA plus installation and running costs.

- To fully replace a network solution would require three generation sets each of capacity 15.3 MVA to meet the supply capacity requirement, at a cost of more than $29 million plus installation and running costs. In this scenario, the conversion to 22kV would not proceed. Hence, this compares to a one-off network investment of approximately $27.1 million (not met).
- To reduce network investment would require one generator of 15.3 MVA capacity at a cost of approximately $9.8 million plus installation and running costs. In this scenario, the conversion of feeders to 22kV would be undertaken to meet reliability and future load growth needs. Hence, this option avoids the installation of a second transformer at EPN only, a reduction in network investment of $9 million (not met).

Timing— Planning process and nature of the investment and likely objectives, together with design requirements mean this is unlikely to be completed in the timeframe required (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. We have no information on current solar generation by customers but estimate that the generation of 15.3 MVA using solar is likely to require more than 230 thousand square meters 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. In addition, the generation profile of solar power may not align to the consumption profile of consumers. Fails to reduce cost and complexity of connection for new developments (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 either 15.3 MVA or 31.2 MVA in this locality. These include zoning, planning and environmental constraints given the land requirements and the lack of evidence of the availability of land for this 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 $3 million and in the Preston environment purchasing large areas of land is likely to be a significant investment. 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 mean this is unlikely to be completed in the timeframe required (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. We estimate that a 2 MW wind turbine would require 6000 sq.m, and a 15.3 MVA wind turbine would require approximately 49 thousand sq.m (https://sciencing.com/much-land-needed-wind-turbines-12304634.html). Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. Fails to reduce cost and complexity of connection for new developments (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 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 $2.25 million 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 this in unlikely to be completed in the timeframe required (not met).

Overall—not a potentially credible option.

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

Identified need— Reduces safety risks of running old plant beyond life. Presently there are 2 large industrial HV customers supplied by EP consuming 0.5 MVA and 0.7 MVA respectively. It's unlikely that this 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. Fails to reduce cost and complexity of connection for new developments (not met).

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—We estimate the cost of a relatively small generator (4 MVA) to be about $3.9 million excluding installation costs. This is unlikely to be commercially viable given the much lower costs of providing this capacity using a network solution.

Timing—Planning process and nature of the investment and likely objectives, together with design requirements mean this is unlikely to be completed in the timeframe required (not met).

Overall—not a potentially credible option.

Large customer energy storage (1.4)

The responses to this option 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.

6.3.2 DEMAND MANAGEMENT/EFFICIENCY

Our 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. Fails to reduce cost and complexity of connection for new developments (not met).

Technical—This type of saving is technically feasible for industrial/commercial users on a certain type of contract and is achievable. However, the magnitude of the reduction required (minimum of 15.3 MVA) is less than one half of current maximum demand (31.2 MVA), which is not able to be met by an improvement in power factor alone (not met).

Commercial—this could be cost-effective (fully met).

Timing—Due to the required demand reduction this option is unlikely to be completed in the timeframe required (not 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%. Based on an average solar generation output of 2kW per installation, (based on generation of 7.2KWH per day - https://www.solarchoice.net.au/blog/how-much-energy-will-my-solar-cells-produce/) approximately 7,800 installations would be required, which exceeds the total number of customers (4743). Even a rate of take up of solar power systems of 100% is not considered to be achievable. This solution also fails to reduce cost and complexity of connection for new developments (not met).

Technical—This option is technically feasible and the technology well understood and tested. At times of peak demand, this solution would likely require energy storage batteries to fully meet the criteria (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— There is uncertainty over whether this could be achieved 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 Option 2.2. Each of Jemena's approximately 4,743 customers would have to reduce consumption by more than 50% for the summer peak to achieve a 15.3 MVA reduction. This scale of reduction is considered unrealistic even if accompanied by incentivizing subsidies (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 and unlikely to be completed in the timeframe required (not 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. In addition, this option is unlikely to be commercially feasible or achievable within the intended timing of the network solution.

Overall—not a potentially credible option.

7. CONCLUSION, CLARIFICATIONS AND NEXT STEPS

7.1 CONCLUSION

The conclusion is 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.

7.2 NEXT STEPS

Jemena will prepare a Draft Project Assessment Report (DPAR) which will present a detailed assessment of all credible network options to address the identified need. In accordance with clause 5.17.4 of the National Electricity Rules, Jemena intend to publish the DPAR for consultation by 31 October 2018.