Jemena Electricity Networks (Vic) Ltd

East Preston (EP) Conversion Stage 6

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

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East Preston (EP) Conversion Stage 6
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Name	Job Title	Date	Signature
Reviewed by:			
Rudi Strobel	Customer & System Planning Manager	26/08/2020	
Approved by:			
Karl Edwards	General Manager Asset Management – Electricity Distribution	27/08/2020	

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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 Preston distribution network has operated since the 1920s with a primary voltage level of 6.6 kV from two 66 kV / 6.6 kV zone substations, Preston (**P**), and East Preston (**EP**), with EP consisting of two switch-houses, EP 'A' and EP 'B'. The surrounding zone substations at Coburg North (**CN**), Coburg South (**CS**) and North Heidelberg (**NH**) all operate at 22 kV. 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 health and safety concerns for staff and the public due to the aging and poor condition of the plant with a high probability of failure and risk of step and touch potentials.

The lower voltage levels in the Preston area limits the ability to provide adequate emergency feeder load transfer during outage conditions, particularly at times of peak demand, resulting in heightened risk to supply reliability for customers in the area. Additionally, as distribution at 6.6 kV has significantly lower transfer capacity than distribution at 22 kV, more feeders are required which results in overhead network congestion in the road reserves. Due to the lack of space in the road reserves, there are minimal opportunities to increase the number of feeders in response to the forecast demand increases in the area. As a result, any new 6.6 kV feeders would need to be undergrounded, which restricts supply options and increases the costs of connection for new customer developments.

The supply arrangements in the Preston area also raises concern regarding the resilience of the network in the event of pole damage, as several poles adjacent to main roads support up to three high voltage feeder circuits—meaning that a vehicle impact to a pole could result in the simultaneous loss of three feeders and loss of supply to a large number of customers. A further issue is that the 6.6 kV network has higher electrical losses compared to a higher voltage (e.g. 22 kV), resulting in higher costs to customers and higher greenhouse gas emissions.

Given the above background, Jemena has previously identified the present Preston distribution network as a priority for investment based on three needs:

- Firstly, the need to protect workers and members of the public from harm caused by equipment failure and risk of step and touch potentials (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 (Reliability); and
- Thirdly, the need to support customer growth in the Preston area by reducing the cost and complexity of connection for new residences and new businesses (Growth).

Summary of findings

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

- Addresses the identified need: by delivering energy to reduce or eliminate the need for investment;
- Technically feasible: there are no constraints or barriers that mean an option cannot be delivered in the context of this investment;

- Commercially feasible: non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment; and
- Timely and can be delivered in a timescale that is consistent with the identified need.

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

Table ES–1: Assessment criteria rating

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

Table ES– shows the initial assessment of non-network options against the Regulatory Investment Test for Distribution (RIT-D) criteria.

Table ES–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 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)				

Jemena has concluded that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Hence, under National Electricity Rules (**NER**) clauses 5.17.4(c) and 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.

Table of contents

List of tables

List of figures

Glossary

Constraint	Refers to a constraint on network power transfers that affects customer service.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 350,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or inter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($6M), in the National Electricity Market (NEM).

Abbreviations

AER	Australian Energy Regulator
CN	Coburg North Zone Substation
CS	Coburg South Zone Substation
DAPR	Distribution Annual Planning Report
DM	Demand Management
EG	Embedded Generation
EP	East Preston Zone Substation (66 kV/6.6 kV)
EPN	East Preston Zone Substation (66 kV/22 kV)
HV	High Voltage
JEN	Jemena Electricity Network
NEM	National Electricity Market
NER	National Electricity Rules
NH	North Heidelberg Zone Substation
NSP	Network Service Provider
P	Preston Zone Substation (66 kV/6.6 kV retired)
PoE	Probability of Exceedance
PTN	Preston Zone Substation (66 kV/22 kV new)
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability

1. Background

The Preston distribution network, located in Melbourne's northern suburbs, has operated since the 1920s with a primary voltage level of 6.6 kV from two 66 kV / 6.6 kV zone substations, Preston (**P**), and East Preston (**EP**), with EP consisting of two switch-houses, EP 'A' and EP 'B'. The surrounding zone substations at Coburg North (**CN**), Coburg South (**CS**) and North Heidelberg (**NH**) all operate at 22 kV.

The assets at both P and EP zone substations were mostly installed in the 1960s, although some elements are significantly older dating back to 1920s. At both zone substations, there were health and safety concerns for staff and the public due to the aging and poor condition of the plant, with a high probability of asset failure and risks associated with step and touch potential. 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 in 2018) followed by the decommissioning of the EP zone substation (noting that EP consists of two switch-houses, EP 'A' and EP 'B').

The difference in voltage levels (P and EP being effectively islanded) limits the ability to provide adequate feeder load transfer during outage conditions, particularly at times of peak demand, further contribution to the risk that customers could experience extended outages under some circumstances. Furthermore, distribution at 6.6 kV has significantly lower transfer capacity than distribution at 22 kV and hence more feeders are required to meet local demand, resulting in overhead network congestion in the road reserves. This congestion results in limited ability to further increase the number of feeders in response to the forecast demand increases in the area. As a result, any new 6.6 kV feeders would need to be undergrounded, which restricts the supply options and increases the cost of connection for new customer developments.

In addition, concerns also arise in relation to the resilience of the network in the event of pole damage, as several poles support up to three high voltage feeder circuits, meaning that a vehicle impact to a pole could result in the simultaneous loss of three feeders and loss of supply to a large number of customers. A further issue is that the 6.6 kV network has higher electrical losses compared to a higher voltage (e.g. 22 kV), resulting in higher costs to customers and higher greenhouse gas emissions.

Given the above issues, JEN developed the Preston area network development strategy to address the assets that are in poor condition and to meet the long term demand for electricity in the area. As an output from the strategy, Jemena embarked on a program of works to convert the P and EP distribution network from 6.6 kV to 22 kV, which formed the Preston conversion program. The construction work under the Preston conversion program began in 2008. To allow the P and EP zone substation to be decommissioned it was first necessary to transfer as much load as possible away to adjacent 22 kV zone substations by converting the assets from 6.6 kV to 22 kV voltage.

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 66 kV / 22 kV zone substation (Preston (PTN)) to be constructed. In 2018 the old P zone substation was decommissioned, and the new PTN zone substation was constructed on the same site which was recently commissioned with two new 66 kV / 22 kV 20/33 MVA transformers in March 2020. The new PTN zone substation provides improved 22 kV capacity and leaves EP as one of the last two remaining 6.6 kV zone substations in the JEN's network, supporting the residual 6.6 kV assets in the East Preston area, supplying approximately 4,900 consumers.

In November 2017, the Australian Energy Regulator (**AER**) introduced a new requirement that impacts these plans. It required that a Regulatory Investment Test (**RIT-D**) should be undertaken that includes the issue of a non-network options report for those projects greater than $10 million[1] 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).

[1] In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 to end of December 2021, this cost threshold will be $11 million. Also see AER, Final determination: Cost thresholds review, November 2018, p.14.

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[2]. 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] In accordance with the AER Final Application Guidelines RIT-D (14 December 2018), from 1 January 2019 this cost threshold will be $6 million.

1.1 RIT-D Process

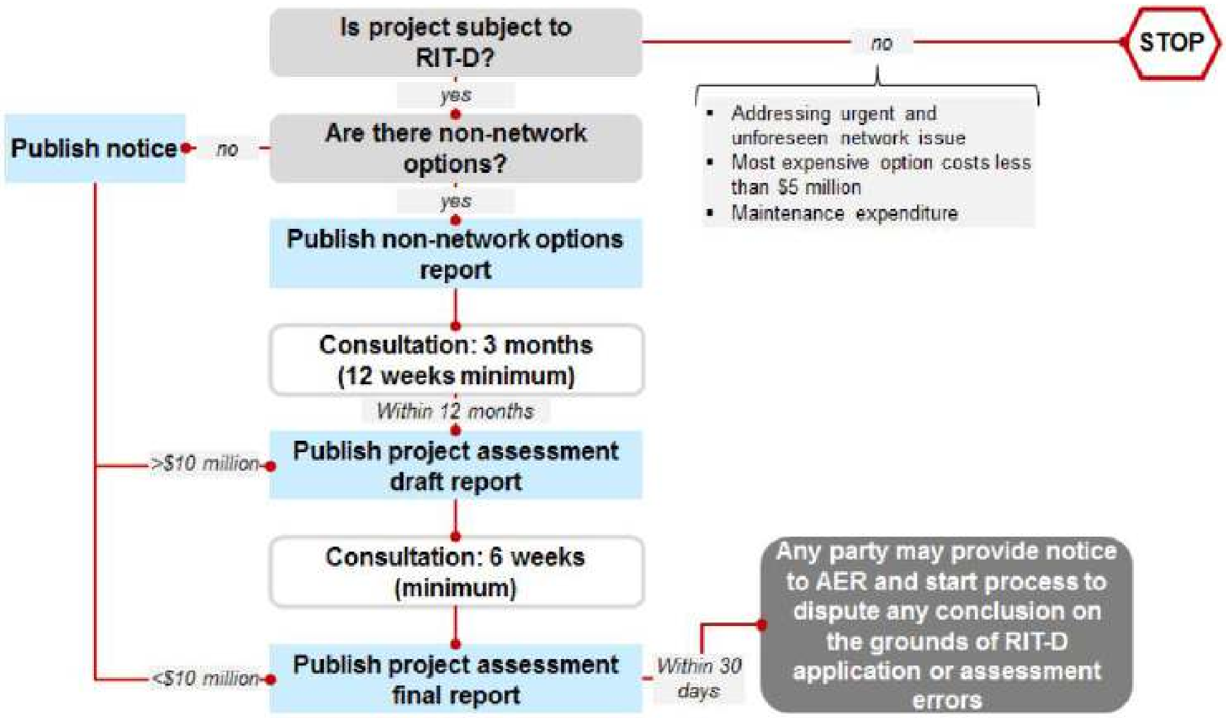
The Regulatory Investment Test for Distribution (RIT-D) process is summarised in Figure 1–1. This shows that the first step is to screen for non-network options by determining whether they are likely to form:

- A potential credible option(s); or
- A significant part of one or more potential credible options to address the identified need.

This report:

- Summarises the non-network screening requirements and the assessment approach (Section 2)
- Describes the identified need the project is aiming to address (Section 3)
- Describes the network options tested to date (Section 4)
- Assesses the potential of non-network options to help address the identified need (Section 5)
- States the conclusion reached on the need for a non-network options report (Section 6).

Figure 1–1: The RIT-D Process[3]



[3] Source: AER Final Application Guidelines RIT-D (14 December 2018).

2. Screening Requirements and Approach

This section of the report:

- Defines the Australian Energy Regulator's (AER) screening requirements as set out in the documents:
  - *AER-Final Application guidelines RIT-D - December 2018* (https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018);
  - National Electricity Rules (NER) Version 145 (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 (AER's Application Guidelines Section 6.1):

- Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or Smart meters and associated cost-reflective pricing);
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity).

An identified need is defined in Chapter 10 of the NER as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network.

According to the AER's Application Guidelines (Section 3.1), an identified need may be addressed by either a network or a non-network option and:

- May consist of an increase in the sum of consumer and producer surplus in the NEM, or an identified need may be for reliability corrective action as per NER 5.17.1(b), where the NER 5.10.2 defines reliability corrective action as a NSP investment in its network to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.
- 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. This objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in the RIT-D report. Framing the identified need as a proposal to consumers should assist the RIT-D proponent in demonstrating why the benefits to consumer would outweigh the costs. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

A credible option is defined in Clause 5.15.2(a) of the NER as an option, or group of options that:

- Addresses (or address) the identified need;
- Is (or are) commercially and technically feasible; and
- Can be implemented in sufficient time to meet the identified need.

NER 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 option.

Jemena have interpreted the guidance to mean that a credible option could also 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 (AER's Application Guidelines Example 22, page 73).

2.2 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 2.1);
- 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 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 workers and members of the public from harm caused by equipment failure and risk of step and touch potentials (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 (Reliability); and
- Thirdly, the need to support customer growth in the Preston area by reducing the cost and complexity of connection for new residences and new businesses (Growth).

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 when the currently committed works are complete, which includes the transfer and conversion of four EP feeders from 6.6 kV to 22 kV. The further stages are set out in the next chapter. This non-network screening report is based on the network that will exist in June 2021 and the needs identified for that network.

3.1 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.

3.1.1 Condition of Plant

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 critical point with a very high probability of failure. The results demonstrate the switchgear and circuit breakers at EP (Type J18 and OLX) are at risk of increased failures and have an increased probability of a catastrophic failure.

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 will further deteriorate over time.

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

- Severe injury or death to operating personnel and the general public in the vicinity of the substation.
- Risk of step and touch potentials causing injuries to personnel.
- Risks to JEN customers associated with an extended period of supply interruption.

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

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

- ELE PL 0029 Preston Area Network Development Strategy

In addition to the deteriorated condition of primary equipment at EP, the secondary equipment (e.g. relays, DC batteries etc.) are also operating well beyond their engineering life and are installed on asbestos type panels. 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). It is also expected that over the coming 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.

3.1.2 Credible Solution Requirements

Credible solutions would be required to allow the decommissioning of the existing assets at EP zone substation, including transformers, switchgear and secondary equipment to ensure 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 zone substation. This is normally calculated through modelling load at risk under system normal condition 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 annualised cost of augmentation.

This will depend on the design and capacity of the current network, transfer capability and the forecast load, which are presented below.

3.2.1 Load Forecasts

The actuals demand and forecasts for EP 'A' and EP 'B' are shown below in Figure 3-1 and Figure 3-2. The forecasts for the supply area show that the maximum expected demand for EP 'A' is 10.8 MVA and for EP 'B' is 15.5 MVA for the summer 10% PoE in 2021. It is noted the forecast demand at EP zone substation is relatively flat between the 2021 and 2026 period. 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 6.6 kV system and hence are likely to be supplied from the more remote 22 kV system (discussed further in Section 3.2.4).

Figure 3–1: EP ‘A’ Demand Forecasts

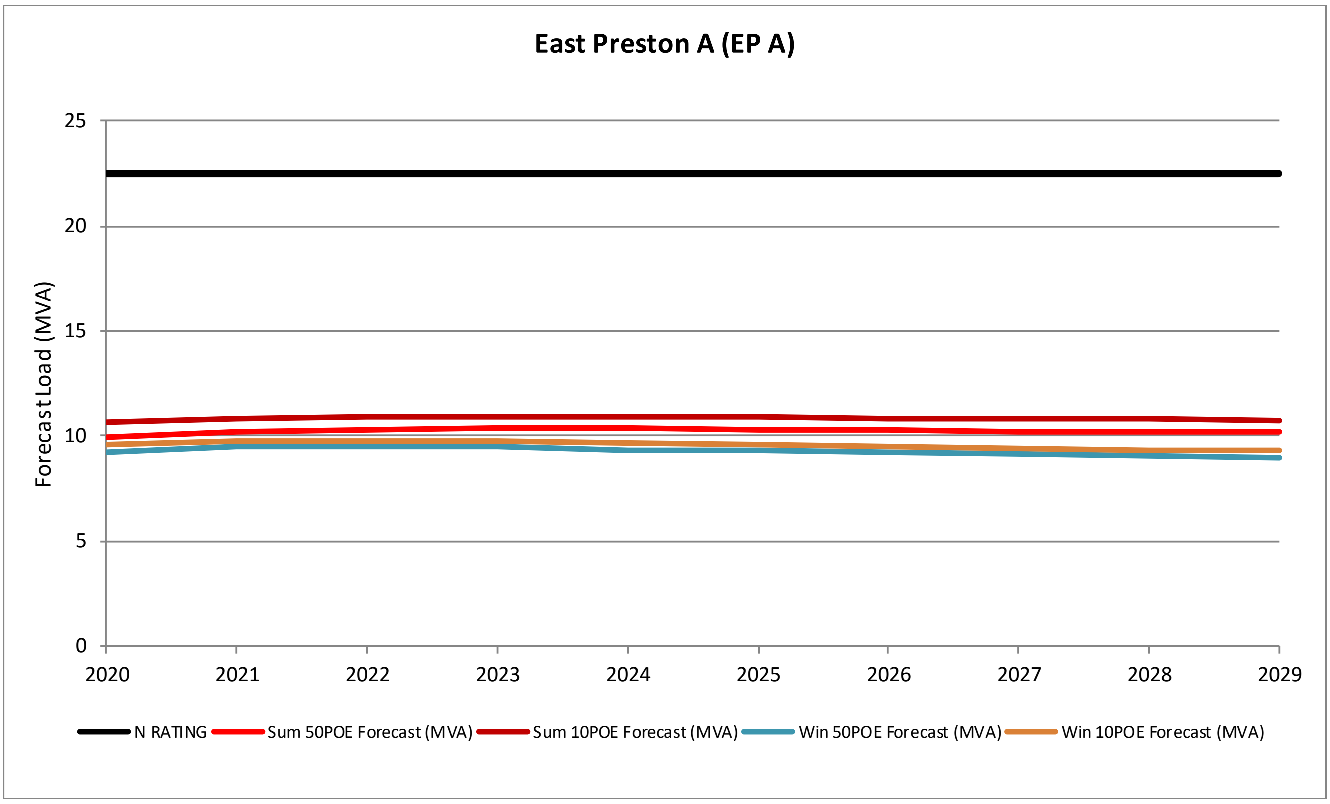
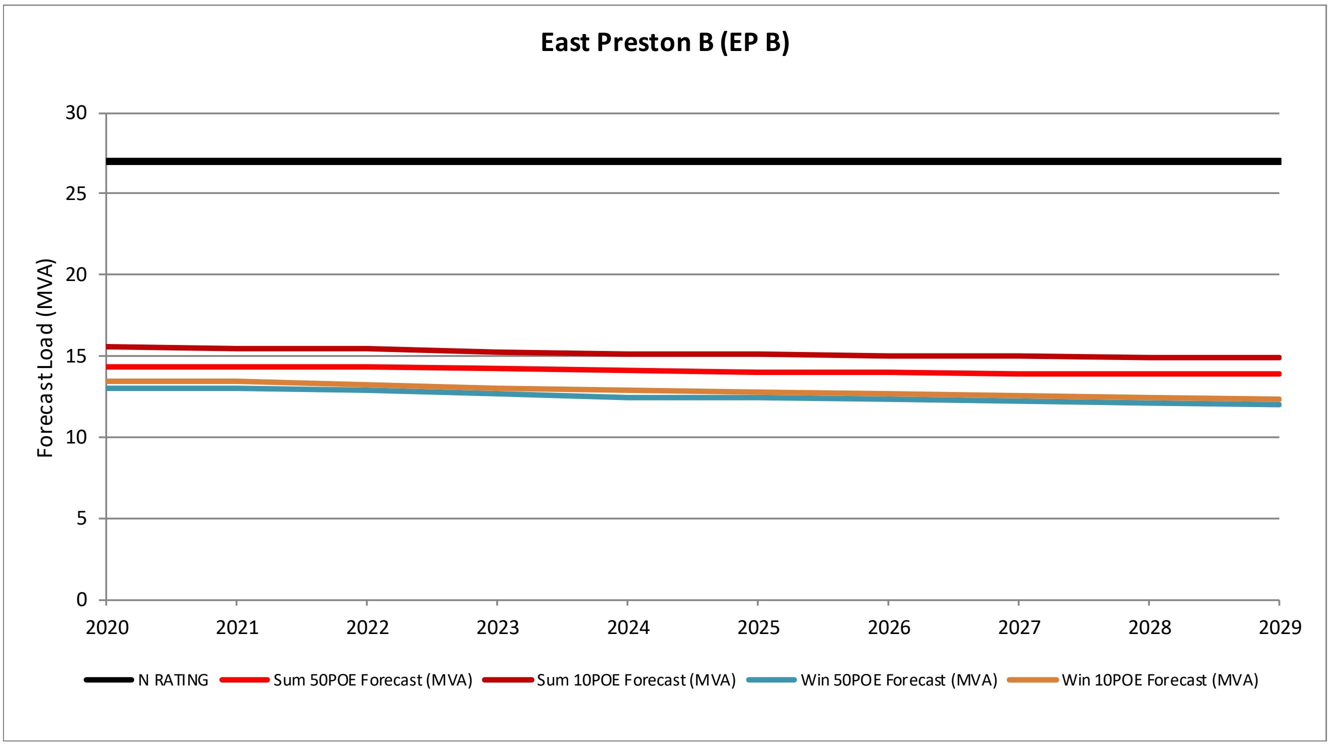


Figure 3–2: EP ‘B’ Demand Forecasts



3.2.2 Zone Substation Capacities

The zone 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 are set out below.

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

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

Zone Substation	Stage (planned in service date)			
	EP Stage 5 (Jun' 2021)	EP Stage 6 (Nov' 2022)	EP Stage 7 (Nov' 2023)	EP Stage 8 (Nov' 2024)
EP 'A'	N Rating = 22.5 MVA N-1 cyclic Rating = 22.5 MVA Load transfer capacity = 0 MVA	Decommissioned	Decommissioned	Decommissioned
EP 'B'	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	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

3.2.3 Credible Solution Requirements

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. Table 1- 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 1-2: Credible Solution Capacity Requirements (2021)

SCENARIO	FORECAST LOAD (MVA)	CURRENT NETWORK CONTRIBUTION (MVA)	CREDIBLE SOLUTION CONTRIBUTION (MVA)
Decommissioning of EP 'A' and EP 'B'	26.3	0	26.3
Scenario - Decommissioning of EP 'A' transformer and associated equipment	EP 'A': 10.8 EP 'B': 15.5 Total: 26.3	EP 'A': 0 EP 'B': 15.5+0=15.5 Total: 15.5	10.8
Scenario - Decommissioning of EP 'B' transformer or associated equipment	EP 'A': 10.8 EP 'B': 15.5 Total: 26.3	EP 'A': 10.8+0=10.8 EP 'B': 0 Total: 10.8	15.5

By June 2021 following the completion of EP Stage 5, the transfer capability between EP 'A' and EP 'B' switchhouse will reduce to zero. Hence the load transfers between the two switchhouse does not impact the assessment, and the load at risk at the time of maximum demand would be 10.8 MVA for EP ‘A’, and 15.5 MVA for EP ‘B’.

3.2.4 Potential Growth

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 6.6 kV system and connection to the more remote 22 kV system.

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 12 MVA.

Salta Properties have plans for 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.

3.2.5 Credible Solution Requirements

Credible solutions would be required to be scalable to meet future load growth needs for the wider Preston supply area.

4. 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 1-2. EP Stage 5 is committed and currently in progress for an in-service date of June 2021.

Table 1-2: Preston Area Network Program

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	Mar 2020	Decommission P zone substation & establish new 66/22kV two transformers PTN zone substation
EP Stage 5	Jun 2021	Conversion of EP 'A' feeders and distribution substations

Prior to committing to the next stage to progress with the conversion of EP 'A' feeders and distribution substations, a review was undertaken that resulted in a 2020 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 Program at the end of P Stage 6 and running the remaining 6.6 kV network to failure
- Option 2 – Continue the Preston Conversion Program which includes a 2nd transformer at EPN
- Option 3 – Continue the Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN
- Option 4 – Delay Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to Fairfield (FF)

The preferred option was to continue the Preston Conversion Program as described below in Table 1-3.

Table 1-3: Preferred Network Solution (Staged)

Stage(s)	In service date	Cost estimate	Anticipated works
EP Stage 6	November 2022	$7.7M	Decommission of EP 'A' zone substation and install 2nd transformer at EPN zone substation
EP Stage 7	November 2023	$13.2M	Conversion of EP 'B' feeders and distribution substations

EP Stage 8	November 2024	$8.4M	Conversion of EP ‘B’ feeders and distribution substations. Decommission of EP ‘B’ zone substation.
TOTAL		$29.3M	

5. Assessment of non-network options

Potential non-network options that could meet the project objectives (as envisaged in the AER RIT-D application guidelines Section 6.1) are listed below:

- Demand Management (DM) - Any measure or program targeted at reducing peak demand (e.g. automatic control schemes, energy efficiency programs or demand response arrangements with customers)
- 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 1-4.

Table 1-4: 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 (June 2020) for each substation are shown below in Table 1-5.

Table 1-5: 2020 Preston Customer Breakdown

Customer Type	East Preston ‘A’	East Preston ‘B’	East Preston (EPN)	Total
All customers	903	3,933	1,714	6,550

Figure 5–1, Figure 5–2 and Figure 5–3 below shows the customer contribution to peak demand at EP ‘A’, EP ‘B’ and EPN zone substations. Commercial and Industrial customers account for approximately:

- 7 MW load during peak demand at EP ‘A’;
- 10 MW load during peak demand at EP ‘B’; and
- 23 MW load during peak demand at EPN.

Figure 5–1: EP 'A' Customer Contribution to Peak

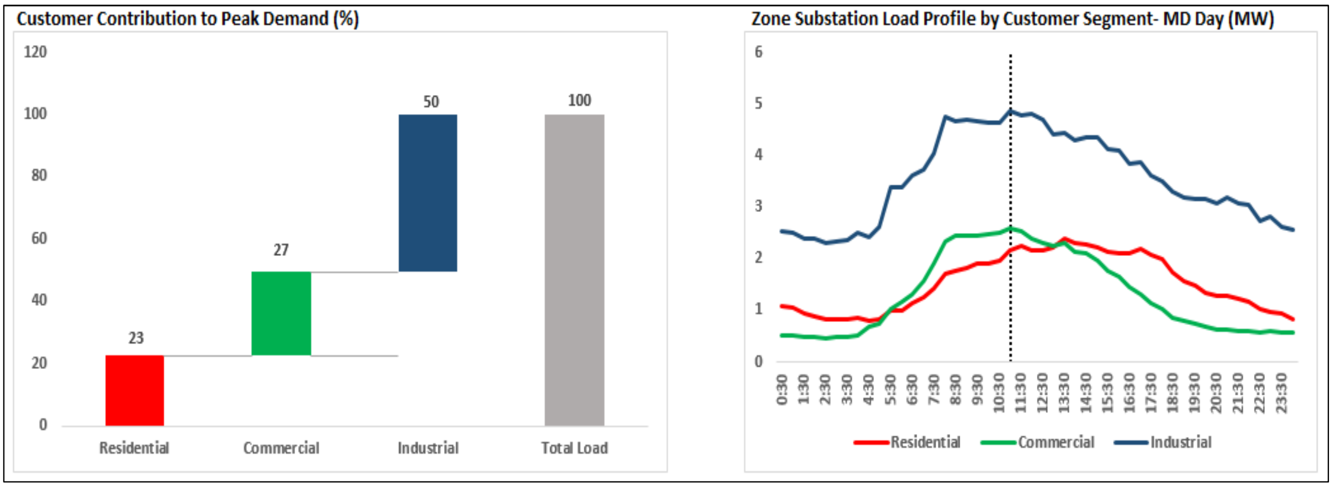


Figure 5–2: EP 'B' Customer Contribution to Peak

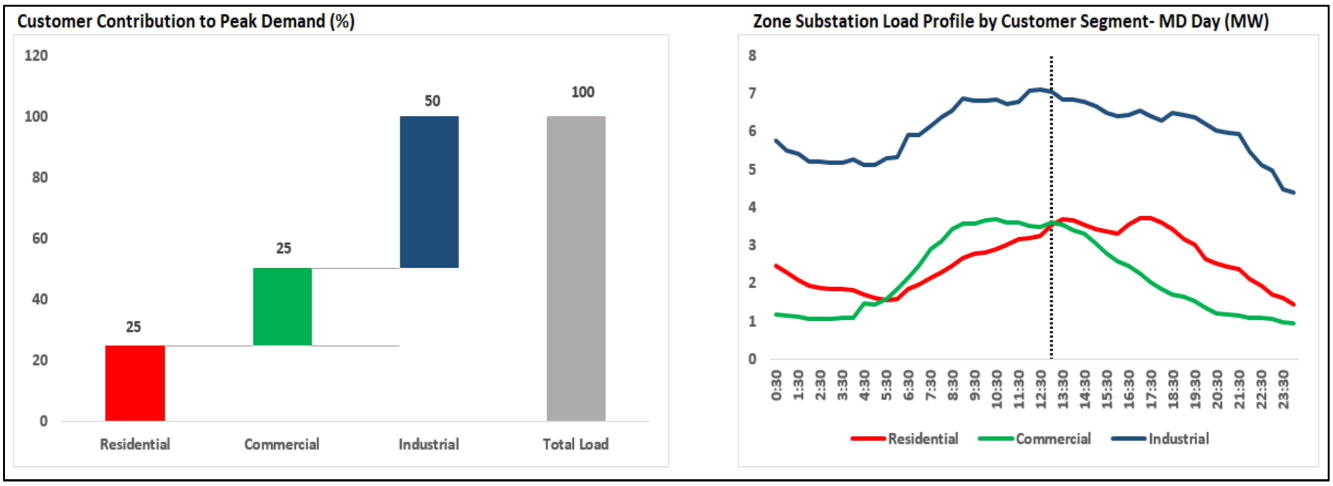
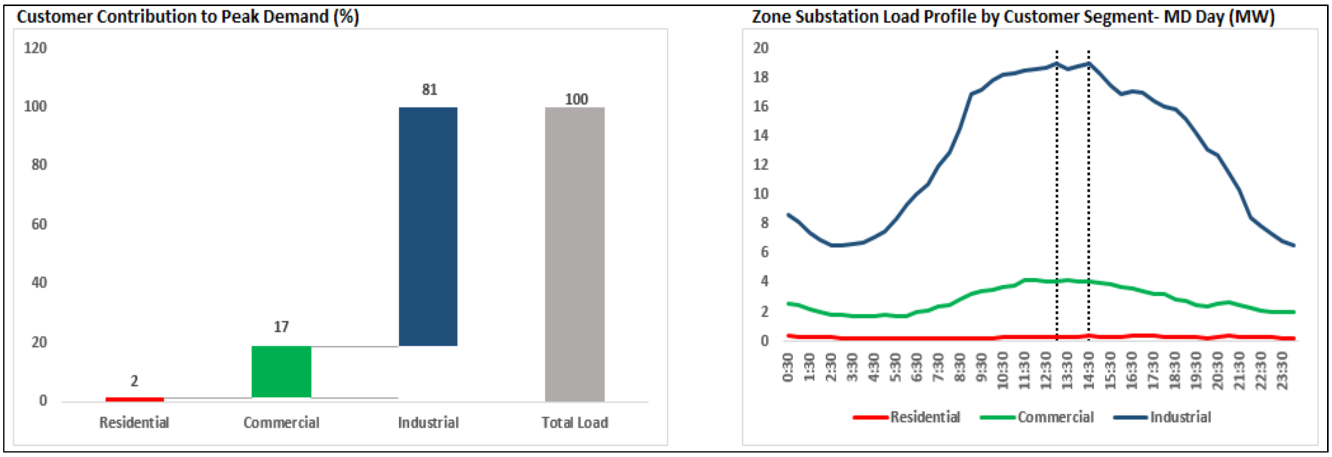


Figure 5–3: EPN Customer Contribution to Peak



At EP, there is currently one HV customer with a maximum demand of 375 kVA. In addition, there is no HV connected embedded generation supplied from EP zone substation apart from small residential and commercial solar PV. The total overall capacity from small solar PV at EP is 1.8 MW (in March 2020), derived from 490 solar installations. This contribution is not expected to change materially such that it would impact the minimum capacity required of a non-network solution.

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. Installing some network assets and meeting the remaining capacity through a non-network option.

A viable non-network solution would involve implementing measures capable of meeting the maximum forecast demand 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 26.3 MVA.

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

- Two generators each supplying 26 MVA
- Or three generators each supplying 13 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 20 MVA, the non-network generation component could be reduced to two generators of 20 MVA or three generators of 10 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 $27M (e.g. providing 3 generator each costing $9.0M = $27M 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 preferred network option of around $7.7M for installation of a 2nd 66/22 kV transformer.

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 – Installing some network assets and meeting the remaining capacity through a non-network option

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 EPN zone substation to have adequate capacity to enable EP zone substation to be retired. The timing of the second transformer at EPN (2022) is currently set to allow the conversion of the

EP ‘B’ feeders to 22 kV (2023) and the subsequent decommissioning of the EP ‘B’ zone substation (2024). 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 at EPN when operating under a N-1 condition (0 MVA) and the forecast load. This value is approximately the load currently supplied by EP ‘B’ (15.5 MVA) if the remaining feeders from EP ‘A’ are converted over to EP ‘B’ which allows for EP ‘A’ to be retired in which this network element would costs around $1.5M.

A viable non-network generation option that could meet EP ‘B’ load demand requires one generator supplying 15.5 MVA (assuming no demand management or greater efficiency). This is likely to cost at least $11M (gas generation excluding 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 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 5–4 shows the rating scale applied for assessing non-network options.

Figure 5–4: 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).

Figure 5–5 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.

Figure 5–5: 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 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)				

5.4 Non-network assessment commentary

5.4.1 Generation and storage

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

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

Identified need – Reduces safety and reliability risks of running old plant beyond end of 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 26.3 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. 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. Due to the 6.6 kV 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. For example, the minimum capacity of installing a 15.5 MVA gas fired generator at a cost of approximately $11M plus installation and running costs which does not provide any savings compared to installing a second transformer which costs $7.7M. It is noted that non-network proponents rather than Jemena would bear the cost of these additions and they would recoup these costs through selling power generated at market prices. The scale of estimated capital costs illustrates the quantum of additional capital costs compared to a network solution and this will lead to a much higher cost per MWh compared to the preferred network solution (**Not met**).

Timing – Planning process and nature of the investment and likely objectives, together with design requirements 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 and reliability 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 15.5 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. As noted in Section 5, solar installations in EP provide a relatively small capacity of 1.8 MW. 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 15.5 MVA or 26.3 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. In addition solar generation alone does not provide the base-generation required (**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 (both for the generators and any required 6.6 kV connections to EP) 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 and reliability 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 15.5 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 unlikely there is adequate site available in terms of elevation and wind conditions for wind generation within a densely urban suburb. The planning constraints and environmental factors involved in securing planning permission for using land for this purpose are very significant and the use of land for this purpose unlikely to be allowed (**Not met**).

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

Timing – The requirement to coordinate the installation of generation across a relatively large number of industrial power consumers together with likely planning requirements mean this is 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 and reliability risks of running old plant beyond life. Presently there is only one industrial HV customer supplied by EP consuming up to 0.4 MVA during peak loading periods. 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 *2019 Distribution Annual Planning Report* (Section 5.9.4) on customer proposals reports that:

In 2019, Jemena has received three connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this low level of enquiries 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 particularly due to the current high fault levels at EP (**Not fully met**).

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

Timing – Planning process and nature of the investment and likely objectives, together with design requirements (both for turbines and any required 6.6 kV connections to EP) 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 (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

Under both non-network assessment scenarios, there is a requirement to meet the maximum demand forecast energy requirements with a level of redundancy to cover this need when the largest single source of power fails (an N-1 situation). As there is no transfer capability to surrounding zone substations, there is no way a fully demand management solution could be implemented without a combination of embedded generation as all load would be required to be shed. A combination of embedded generation and demand management would lead to a reduction in the required generating capacity for non-network solutions. In the assessment commentary for the demand management/efficiency options, non-network assessment scenario 2 is considered with embedded generation of 10 MVA.

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

Identified need – Reduces safety and reliability 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 15.5 MVA) is less than one half of current maximum demand (26.3 MVA), which is not able to be met by an improvement in power factor alone. In addition, a 10 MVA of embedded generation would face planning and technical constraints (**Not fully met**).

Commercial – this could be cost-effective however the estimated cost of 10 MVA embedded generation is unlikely to be commercially viable (**Not met**).

Timing – Due to the required demand reduction this option is unlikely to be completed in the timeframe required (**Not fully met**).

Overall – Not a potentially credible option.

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

Identified need – Reduces safety and reliability risks of running old plant beyond life. In 2019, solar household penetration in Australia is on average 22% of the country's total electricity (https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy). Satellite imagery suggests that the proportion for the EP catchment is unlikely to exceed this average figure. Based on an average solar generation capacity of 3 kW per installation, approximately 5,400 installations would be required to provide 16.3 MVA capacity (26.3 MVA demand – 10 MVA of embedded generation), which exceeds the total number of customers at EP of 4,866. Currently, as noted in Section 5 solar installations in EP provide a relatively small capacity of 1.8 MW. This rate of take up 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. 10 MVA of embedded generation would face planning and technical constraint **(Not 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. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable (**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 JEN's approximately 4,866 customers at EP would have to reduce consumption by approximately 62% during the summer peak period to achieve a 16.3 MVA reduction (16.3 MVA / 26.3 MVA = 62%). 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. 10 MVA of embedded generation would face planning and technical constraint (**Not fully met**).

Commercial – Unclear that this is commercially feasible. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable (**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 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. 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.

6. Conclusions and next steps

6.1 Conclusion

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

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

6.2 Next steps

Jemena 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 30 October 2020.