# Jemena Electricity Networks (Vic) Ltd

## East Preston (EP) Conversion Stage 7 and 8

RIT-D Stage 1: Notice of Determination

# Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east. JEN supplies electricity distribution services to more than 370,000 customers.

Our customers expect us to deliver a reliable electricity supply at an efficient cost. To do this, we must choose the most efficient solution to address current and emerging network limitations. This means choosing the prudent 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 level in the East Preston area limits the ability to provide adequate emergency feeder load transfer during outage conditions, particularly during peak demand. 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 connection costs for new customer developments.

The supply arrangements in the East Preston area also raises concern regarding the resilience of the network in the event of pole damage, as several poles support up to three high voltage feeder circuits. A further issue is that the 6.6 kV network has a higher percentage of electrical losses compared to a higher voltage (e.g. 22 kV).

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

- The need to protect power sector workers and members of the public from harm caused by equipment failure and risk of step and touch potentials (Safety);
- 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
- The need to support growth aspirations for the wider Preston area by reducing the cost and complexity of connection for new residences and new businesses (Customer Connections).

## Approach to screening options

JEN has developed a set of potential network solutions aimed at addressing the identified need. JEN has also investigated whether viable non-network or stand-alone power system (**SAPS**) solutions exist, in which case JEN is required to publish an options screening report and request stakeholder submissions, as detailed in National Electricity Rules (**NER**) clause 5.17.4, paragraph (e).

However, in the event that there are no potential credible non-network or SAPS options that could address the identified need (or any combination of those options with or without a network option), JEN is instead required to publish a Notice of Determination in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the NER.

## Summary of findings

The criteria used by JEN to assess the potential credibility of non-network and SAPS options included:

- **Addressing the identified need**: reducing or eliminating the supply reliability risks associated with the identified need.
- **Being technically feasible**: there are no technical constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 1–1 shows the rating scale JEN has applied for assessing credibility of non-network and SAPS options.

**Table 1–1: Assessment criteria rating**

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

Table 1–2 shows the initial assessment of potential non-network and SAPS options against the RIT-D criteria.

**Table 1–2: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Economic | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Generation using gas turbines or diesel | | | | |
| 1.2 Generation using grid-scale solar and storage | | | | |
| 1.3 Standby generation (existing large customer) | | | | |
| 1.4 Storage only using grid-scale batteries | | | | |
| **2.0 Demand Management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power and storage systems | | | | |
| 2.3 Broad-based demand response | | | | |
| 2.4 Targeted demand response | | | | |

Based on these results, JEN has concluded that none of the potential non-network or SAPS options investigated (or a combination of options) could represent technically or economically feasible alternatives to adequately address the identified need.

Hence, under NER clause 5.17.4(b), 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. Instead we are required to publish a notice of determination, under clause 5.17.4(d) of the NER, which sets out the reasons for our determination including any methodologies and assumptions used.

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

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# Glossary

| | |
|---|---|
| Amperes (A) | Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps. |
| Capital expenditure (CAPEX) | Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits. |
| Contingency (or 'N-1' condition) | An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements. |
| Energy-at-risk | The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions. |
| Expected unserved energy (EUE) | Refers to an estimate of the probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy. |
| Load-at-risk | The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions. |
| Jemena Electricity Network (JEN) | One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 370,000 customers 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. |
| Network | Refers to the system of 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 capability 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) | An economic viability test that establishes consistent, clear and efficient planning processes for assessing and consulting on distribution network investments over a prescribed limit. |
| Stand Alone Power System | An embedded power system that operates disconnected (islanded) from the network. |
| System Normal (or 'N' condition) | The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration. |
| Value of Customer Reliability (VCR) | Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted). |
| Zone Substation | Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the network. |

| | |
|---|---|
| 10% POE condition (summer) | Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC. |
| 50% POE condition (summer) | Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC. |
| 50% POE and 10% POE condition (winter) | Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC. |

# 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) |
| HV | High Voltage |
| JEN | Jemena Electricity Network |
| NER | National Electricity Rules |
| NH | North Heidelberg Zone Substation |
| NSP | Network Service Provider |
| PoE | Probability of Exceedance |
| PTN | Preston Zone Substation |
| RIT-D | Regulatory Investment Test for Distribution |
| VCR | Value of Customer Reliability |
| 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 |
| EPN | East Preston Zone Substation (66 kV/22 kV) |
| HV | High Voltage |
| JEN | Jemena Electricity Network |
| NEM | National Electricity Market |
| NER | National Electricity Rules |

# 1. Introduction

This section outlines the purpose of the Regulatory Investment Test for Distribution (RIT-D) in relation to the East Preston supply area.

## 1.1 RIT-D purpose and process

Jemena Electricity Networks (Vic) Ltd (**JEN**), being a regulated distribution network service provider (**DNSP**), is required to undertake the RIT-D consultation process in accordance with clause 5.17 of the National Electricity Rules (**NER**). The purpose of the RIT-D is to identify the investment option that best addresses an identified need on JEN's electricity 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 (**NEM**) as well as that arising from changes in Australia's greenhouse gas emissions (the preferred option).[1]

The RIT-D applies in circumstances where a network limitation (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $7 million[2].

As part of the RIT-D process, distribution businesses must also consider non-network and standalone power system (**SAPS**) options when assessing credible options to address the identified need. We are also required to screen for non-network and SAPS options by determining whether they are likely to form a:

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

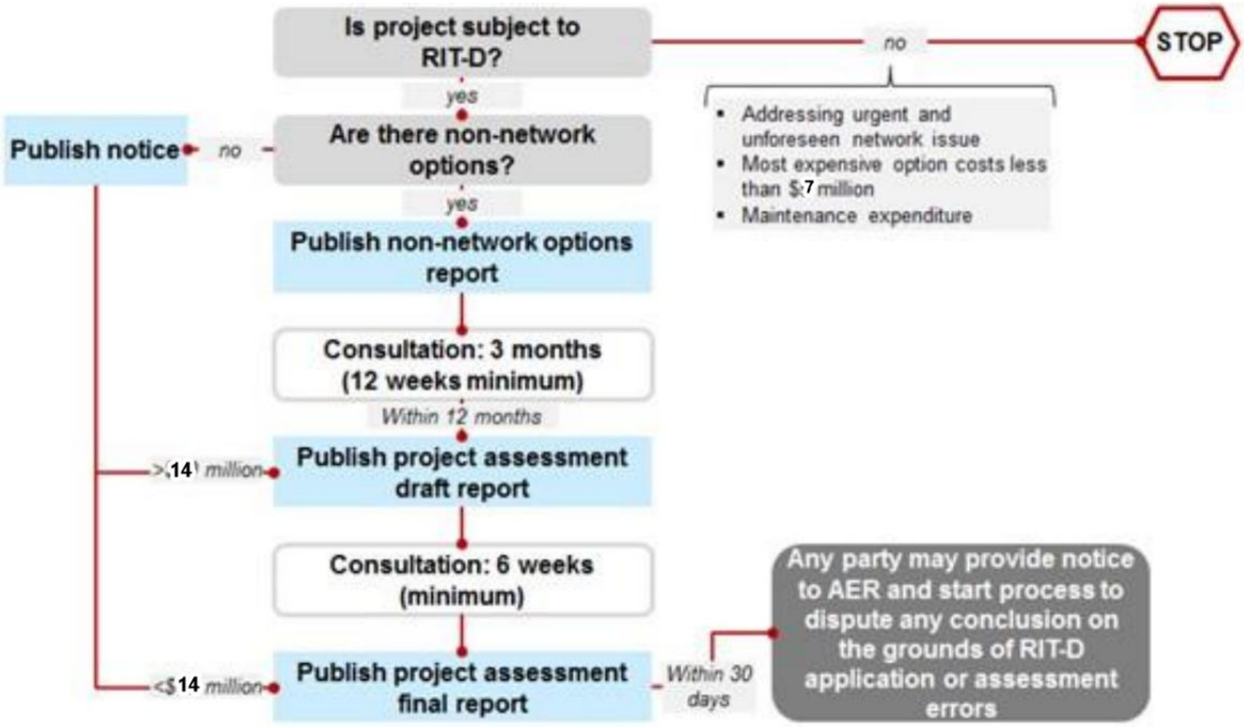
Our evaluation shows that none of the potential non-network or SAPS options JEN has investigated (or a combination of options) forms a significant part of a potential credible option that could adequately address the identified need.

The RIT-D process is summarised in Figure 1–1.

[1] The net economic benefit is defined in the NER to include the sum of (a) the net economic benefit, other than of changes to Australia's greenhouse gas emissions, to all those who produce, consumer or transport electricity in the NEM; and (b) the net economic benefit of changes to Australia's greenhouse gas emissions, whether or not that net benefit is to those who produce, consume or transport electricity in the NEM.

[2] Source: AER 2024 RIT and APR cost thresholds review (November 2024).

**Figure 1–1: The RIT-D Process[3]**




This notice of determination report:

- Summarises the non-network and SAPS screening requirements and the assessment approach (Section 2).
- Describes the identified need JEN is aiming to address (Section 3).
- Describes the network options tested to date (Section 4).
- Describes the potential of non-network and/or SAPS options assessed to help address the identified need (Section 5).
- States the conclusion reached on potential non-network and SAPS options, and next steps (Section 6).

[3] Source: AER Application Guidelines RIT-D (November 2024).

# 2. Screening requirements and approach

This section:

- Defines the option screening requirements as set out in the:
  - AER - Regulatory Investment Test for Distribution application guidelines - 2024 - Version 6; and
  - National Electricity Rules (NER), Version 230, Dated 8th June 2025.
- Describes the approach to assessing the credibility of non-network and SAPS options.

## 2.1 Definitions

Non-network and SAPS options include (from Application Guidelines Section 6.1):

- Any measure or program targeted at reducing peak demand (e.g. direct load control schemes, broad-based or targeted demand response programs)
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity)

An **identified need** is defined in Chapter 10 of the NER as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network. According to the Application Guidelines Section 3.1, an identified need may be addressed by either a network, non-network or SAPS option and:

- May involve meeting any of the service standards linked to the technical requirements of schedule 5.1 of the NER, or in applicable regulatory instruments (reliability corrective action) and/or an increase in the sum of consumer and producer surplus in the NEM.
- RIT-D proponents should express an identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

In describing an identified need, a RIT-D proponent may find it useful to explain what will or may happen if the RIT-D proponent fails to take any action (Application Guidelines Section 3.1).

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

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

Clause 5.15.2(c) conveys that: In applying the RIT-D, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- Energy source;
- Technology;
- Ownership; and
- Whether it is a network, non-network or SAPS solution.

JEN has interpreted the guidance to mean that a credible option could consist of a non-network component and a network component which, when 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 22, page 74).

## 2.2 Approach

JEN's approach to identifying and assessing the credibility of potential non-network and SAPS options for this notice of determination report includes:

- Describing the identified need, by the network limitations driving the proposed investment including the capacity, demand and the minimum contribution required if non-network options are to be potentially credible.
- Describing the credible network options that address the identified need, with a preliminary designation of the preferred network solution.
- Documenting an initial assessment of the range of non-network options against the criteria in clause 5.15.2(a) of the NER described above.
- Concluding whether there is sufficient and appropriate evidence to determine if there are any potential credible non-network or SAPS options, identifying any issues that require further examination.

# 3. Identified need

## 3.1 Description of the identified need

JEN has prepared this non-network screening report to assess whether the demand and safety requirements of the East 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.

JEN has identified the East 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 East 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 2025 and the needs identified for that network.

## 3.2 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.

### 3.2.1 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 detailed 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 East 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.

### 3.2.2 Credible Solution Requirements

Credible solutions would be required to allow the decommissioning of the existing assets at EP zone substation, including transformers, switchgear, secondary and distribution equipment to ensure safety of staff and the public.

## 3.3 Reliability

JEN'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 evaluatign 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)[4].

JEN 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/replacement.

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

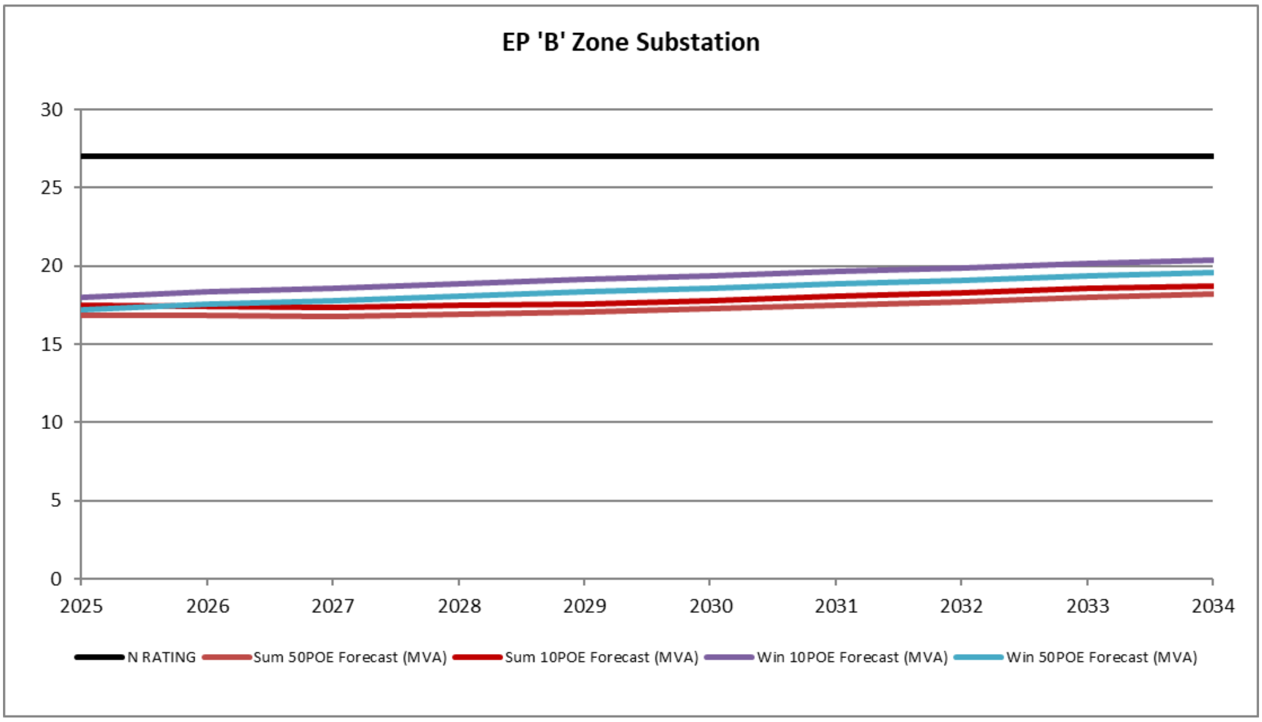
[4] The value of customer reliability is set by the Australian Energy Regulator. The latest VCR was published in December 2024.

### 3.3.1 Network capacity and maximum demand forecasts

As part of the current EP Stage 6 works, EP ‘A’ Zone Substation was decommissioned in late 2023 with EP ‘B’ being the remaining 6.6 kV Zone Substation supplying part of the Preston area. EP has one 66/6.6 kV 27 MVA transformer with two 66/6.6 kV 13.5 MVA, as hot standby transformers supplying ten 6.6 kV feeders

Based on our 2024 load demand forecast, the demand forecast for EP ‘B’ switch-house is shown below in Figure 2–1. The forecasts for the supply area show that the maximum expected demand is 20.4 MVA for EP ‘B’ for the winter 10% PoE in 2034. For EP ‘B’ the forecast demand is relatively flat between 2026 and 2033 following a large step up in demand in the year prior caused by load transfer from EP A as part of EP Stage 6. This forecast includes known spot loads where a customer has made an enquiry or application but does 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.

**Figure 3–1: EP ‘B’ zone substation load forecast**




The N rating of EP ‘B’ is the rating of the No.2 transformer. Given that the condition of the No.3 and No.4 transformers (operating as hot-standby) are in such poor condition and need to be retired, and this means EP ‘B’ will effectively only has one transformer No. 2 that can supply it reliably under N. This is problematic for a reliable supply because EP ‘B’ has no transfer capacity to adjacent zone substations to back it up under N-1 through the 6.6 kV network.

With EP 6.6. kV distribution feeders, there is limited capacity for load transfers on feeders EP33, EP34, and EP36 in the event of an outage. Typically, due to the radial network of a distribution feeder, a feeder should not be loaded well above 85% utilisation under system normal conditions to allow sufficient emergency transfer under outage conditions. In addition to the shortfall of transfer capacity, one of these feeders is forecast to exceed its thermal line carrying capacity during system normal conditions. Table 3-1 present the 10% PoE forecast utilisation for three of EP heavily loaded feeders. The limitations on the EP ‘B’ 6.6 kV feeders are associated with the inability to restore feeder supply under N-1 only due to a lack of spare capacity.

**Table 3-1: Feeder Forecast Utilisation**

| Feeder | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|
| EP33 | 97% | 100% | 103% | 107% | 111% |
| EP34 | 79% | 80% | 81% | 83% | 85% |
| EP36 | 84% | 83% | 82% | 83% | 83% |

The need to provide for growth is fundamental to meeting JEN's distribution licence requirement to make an offer to connect consumers.

Darebin City Council has developed an East Preston Central Structure Plan, which will see significant expansion of Northland and the surrounding areas in future years, including the following initiatives:

- Continuing with Darebin City Council's climate emergency plan to achieve zero greenhouse gas emissions by 2030, a new Zero Emission Bus (ZEB) depot is under construction with the goal to replace all existing busses with electric busses. Over the next 10 years it is forecast 56 EV Busses will be in operation.
- 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 forecast total maximum demand over the next 10 years is 12 MVA.

Other significant developments in the East Preston area include:

- Several large organisation have begun the redevelopment of Preston Market as part of a new 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.
- Northland shopping centre is beginning to develop a new residential precinct which is outlined to include a new high rise building with commercial and residential facilities. It is forecast this will provide 20,000 residents with housing.

With the available infrastructure, the new loads will be difficult and costly to supply at the 6.6 kV voltage level; more so than the recommended solution. At 6.6 kV, 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.

## 3.4 Credible solution requirements to address the identified need

Credible solutions would be required to be scalable to meet future load growth needs and must allow the decommissioning of the existing assets at EP zone substation, including transformers, switchgear, secondary and distribution equipment to ensure safety of staff and the public.

# 4. Network options

As previously noted in this report, the works to address the needs in the East Preston area have already commenced. Works completed to date are shown in Table 4-1. EP Stage 6 is currently in delivery with a in-service date of November 2025.

**Table 4-1: East Preston conversion program status**

| Staging of works | In Service Year | Status | Anticipated Works |
|---|---|---|---|
| P Stage 1 | 2008 | Completed | Conversion of P feeders and distribution substations |
| EP Stage 1 & 2 | 2008 | Completed | Conversion of EP feeders and distribution substations |
| P Stage 2 | 2009 | Completed | Conversion of P feeders and distribution substations |
| P Stage 3 | 2012 | Completed | Conversion of P feeders and distribution substations |
| EP Stage 3 | 2015 | Completed | New 66/22 kV single transformer EPN zone substation |
| P & EP Stage 4 | 2016 | Completed | Conversion of P & EP feeders and distribution substations |
| P Stage 5 | 2017 | Completed | Conversion of remaining P feeders and distribution substations |
| P Stage 6 | 2020 | Completed | Decommission P zone substation & establish new 66/22 kV two transformers PTN zone substation |
| EP Stage 5 | 2022 | Completed | Conversion of EP feeders and distribution substations |
| EP Stage 6 | 2025 | In Construction | Decommission of EP ‘A’ zone substation & install 2nd transformer at EPN zone substation |

Prior to committing to the final stages to progress with the conversion of all EP feeders and distribution substations, a review was undertaken as part of an update to our network development strategy that confirmed the plan and staging of the required works. The network development strategy considered and assessed the following network options:

- Option 1: Do Nothing - Stopping the East Preston Conversion Program at the end of EP Stage 6 and running the remaining 6.6 kV network to failure;
- Option 2: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN) (preferred option);
- Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN);
- Option 4: Complete EP Stage 7 of the 6.6 kV to 22 kV East Preston Conversion and transfer the remaining EP load to Fairfield (FF);
- Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets.

The preferred option was to continue the final two stages of the East Preston conversion from EPN as described below in Table 4–2.

**Table 4–2: Option 2 Remaining Stages of Work**

| Staging of works | In Service Year | Cost Estimate | Anticipated Works |
|---|---|---|---|

| | | | |
|---|---|---|---|
| EP Stage 7 | 2028 | $30.0M | Conversion of EP 6.6 kV feeders and distribution substations to 22 kV, supplied by EPN. |
| EP Stage 8 | 2030 | $18.4M | Conversion of remaining EP 6.6 kV feeders and distribution substations. Decommission EP ‘B’ Zone Substation and convert a portion of FF90 from 6.6 kV to 22 kV, supplied by EPN. |

## 4.1 Option 1 - Do nothing (base case)

Option 1 involves maintaining the current operating regime. The capital cost of this option is assumed to be zero, with the cost of unplanned outages due to network asset loading and running the assets to failure through involuntary load shedding represented by the value of EUE.

## 4.2 Option 2 - Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN) (preferred option)

Option 2 involves:

**EP Stage 7:** Establish two new 22 kV feeders from EPN zone substation from the new No.2 22 kV bus to transfer and convert eight 6.6 kV feeders (EP27, EP28, EP32, EP33, EP35, EP37, EP41 and EP42) from EP ‘B’ to 22 kV.

**EP Stage 8:** Establish one new 22 kV feeder from EPN zone substation No.2 22 kV bus to convert the remaining feeders EP34, EP36 and EP41 from EP ‘B’ from 6.6 kV to 22 kV and convert an isolated section of feeder FF90 from 6.6 kV to 22 kV. Once completed, decommission and remove of all EP ‘B’ assets. EP zone substation will then be fully decommissioned by 2030.

| Stages | In Service Year | Cost estimate (Real 2024 $) |
|---|---|---|
| EP Stage 7 | 2028 | $30.0M |
| EP Stage 8 | 2030 | $18.4M |

## 4.3 Option 3 - Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)

Option 3 involves:

**EP Stage 7:** Establish two new 22 kV feeders from PTN zone substation and convert eight 6.6 kV feeders (EP27, EP28, EP32, EP33, EP35, EP37, EP41 and EP42) from EP ‘B’ to 22 kV.

**EP Stage 8:** Transfer load from EPN33 to PTN14 and extend EPN33 to convert the remaining feeders EP34, EP36 and EP41 from EP ‘B’ from 6.6 kV to 22 kV and convert an isolated section of feeder FF90 from 6.6 kV to 22 kV. Once completed, decommission and remove of all EP ‘B’ assets.

| Stages | In Service Year | Cost estimate (Real 2024 $) |
|---|---|---|
| EP Stage 7 (two new feeders from PTN) | 2028 | $38.6M |
| EP Stage 8 | 2030 | $18.4M |

## 4.4 Option 4 – Complete EP Stage 7 of the 6.6 kV to 22 kV East Preston Conversion and transfer the remaining EP load to Fairfield (FF)

Option 4 involves:

**EP Stage 7:** Establish two new 22 kV feeders from EPN zone substation from the new No.2 22 kV bus to transfer and convert eight 6.6 kV feeders (EP27, EP28, EP32, EP33, EP35, EP37, EP41 and EP42) from EP 'B' to 22 kV.

**EP Stage 8:** Establish three new 6.6 kV feeders from FF zone substation No.4 6.6 kV bus to transfer the remaining feeders EP34, EP36 and EP41 from EP 'B' from 6.6 kV to 22 kV and convert an isolated section of feeder. Once completed, decommission and remove of all EP 'B' assets.

| Stages | In Service Year | Cost estimate (Real 2024 $) |
|---|---|---|
| EP Stage 7 | 2028 | $30.0M |
| Install three new FF feeders and load transfer | 2030 | $14.9M |
| On-going distribution replacement works and retire EP | 2031-35 | $16.8M |

## 4.5 Option 5 – Undertake Like For Like Replacement Of The Remaining EP 6.6 KV Distribution Assets

Option 5 involves retaining 6.6 kV as the primary distribution voltage level for the East Preston areas and replacing the ageing 6.6 kV distribution assets progressively as the end of life is reached and maintenance becomes expensive and inefficient.

This option involves building a new 66/6.6 kV zone substation on a new site. JEN does not own any spare zone substation land in Preston and therefore land would need to be purchased. Building a new zone substation on another site would involve expensive alterations to 66 kV lines, feeder routes and communications cables. It would require land purchased in the Preston area which would be a costly exercise due to high land prices and there would be difficulty finding a suitable industrial site in a well-established high-density urban residential and commercial area.

| Stages | In Service Year | Cost estimate (Real 2024 $) |
|---|---|---|
| Establish a new 66/6.6 kV zone substation and retire EP zone substation | 2028 | $49.0M |
| Distribution replacement works and feeder augmentation | 2029 | $8.2M |
| Distribution replacement works | 2030 | $4.8M |
| Distribution replacement works and feeder augmentation | 2031 | $6.7M |
| Distribution replacement works | 2032 | $3.7M |
| On-going distribution replacement works | 2033-38 | $29.9M |

# 5. Non-network and SAPS options

Potential non-network and SAPS options that could meet the investment objectives (as envisaged in the Application Guidelines Section 6.1) are listed below:

- **Demand Management** - Any measure or program targeted at reducing peak demand, including direct load control, broad-based demand management, or targeted customer demand response programs; and/or
- **Embedded Generation** - Increased local or distributed generation/supply options, including using capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity.

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

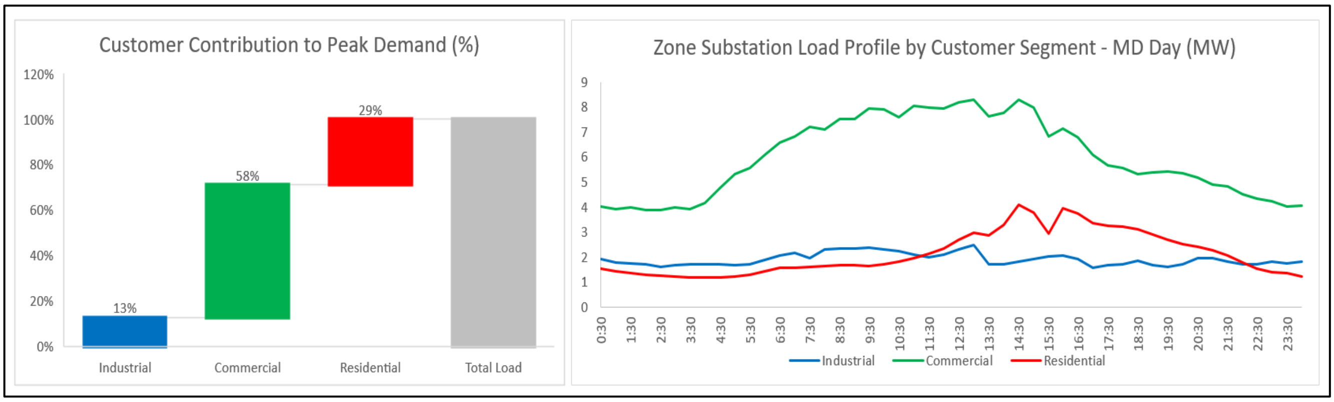
Potential embedded generation, energy storage or demand reduction solutions are limited by the demand of a customer, i.e. an individual customer can only reduce its demand to zero. Typically, the absence of large customers limits the potential for large demand side solutions. The 2024 breakdown of customers in East Preston is shown below in Table 5–1.

**Table 5–1: East Preston customers by category (2024)**

| Customer Type | EP ‘B’ |
|---|---|
| Residential | 3,632 |
| Commercial | 325 |
| Industrial | 16 |
| Total | 3,974 |

Figure 5-1 below shows the customer contribution to peak demand at EP ‘B’ zone substation servicing the East Preston supply area. Commercial and Industrial customers account for approximately 14 MW load during peak demand at EP ‘B.

**Figure 5-1: EP ‘B’ Customer Contribution to Peak**




At EP, 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 4.3 MW (in April 2024), derived from 642 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 and SAPS 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 and SAPS option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

Potential non-network 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 and SAPS option.

A viable non-network and SAPS 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 20.4 MVA.

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

## 5.2 Non-network and SAPS options assessment scenarios

The aim in defining potential non-network and SAPS scenarios, is to test whether a non-network or SAPS option (or combination of options) is a viable way to avoid or reduce the scale of a network investment in a way that efficiently addresses the identified need. A non-network or SAPS option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g., generation plus demand management).

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

A viable generation and storage SAPS options that that replaces the capacity currently provided by EP that reliably meets customer requirements in an N-1 situation requires:

- Two generators each supplying 20 MVA; or
- Three generators each supplying 6.7 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 demand to 20 MVA, the non-network generation component could be reduced to two generators of 20 MVA or three generators of 6.7 MVA each.

The costs of the total replacement scenario are likely to exceed those of the preferred network option. For example, the Engineer Procure and Construct (EPC) Capex cost of small gas-fired generator is approximately $1.25 million (real 2024) per MW[5]. For two 20 MW of generation, the cost will be over $50 million (real 2024), once operating costs are included. 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. Additionally, the maximum demands of individual customers indicate that no potential existing customer owned generation would be large enough to meet the need.

[5] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

### 5.2.2 Scenario 2 – Non-network or SAPS option to meet identified need in part

Alternative 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 EP zone substation to be retired and support 20 MVA of load securely under N-1 condition. For a non-network or SAPS option to meet part of the identified, it would be required to support either the amount of load converted from EP Stage 7 or EP Stage 8 which is approximately 10 MVA. The timing of the second transformer installation at EPN (2025) is currently set to allow the conversion of the EP 'B' feeders to 22 kV (EP Stage 7 in 2028) and the subsequent decommissioning of the EP 'B' zone substation (EP Stage 8 in 2030). The converting of Stage 7 or Stage 8 could be avoided by a non-network solution that matches the forecast load transferred. This value is approximately part of the load currently supplied by EP 'B' (10 MVA).

A viable non-network generation option that could meet part of the EP 'B' load demand to replace Stage 7 or Stage 8 requires two generators supplying 10 MVA (assuming no demand management or greater efficiency). This is likely to cost over $25 million (real 2024), once land, operating and other establishment costs are included.

The maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need, hence the generation would likely be a majority of new grid-connected systems. Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

## 5.3 Non-network and SAPS options assessment criteria

This section reports on the credibility of potential non-network and SAPS options as alternatives or supplements for the preferred network option. The criteria used to assess the potential credibility was:

- **Addressing the identified need**: reducing or eliminating the supply reliability risk associated with the asset overloads.
- **Being technically feasible**: there are no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 5–2 shows the rating scale applied for assessing non-network options.

**Table 5–2: Assessment criteria rating**

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

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

Table 5–3 shows the initial assessment of non-network and SAPS options against the RIT-D criteria. The assessment identified some non-network or SAPS 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, demand response and storage options are set out in the following sections.

**Table 5–3: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Economic | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Generation using gas turbines or diesel | | | | |
| 1.2 Generation using grid-scale solar and storage | | | | |
| 1.3 Standby generation (existing large customer) | | | | |
| 1.4 Storage only using grid-scale batteries | | | | |
| **2.0 Demand Management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power and storage systems | | | | |
| 2.3 Broad-based demand response | | | | |
| 2.4 Targeted demand response | | | | |

## 5.4 Non-network and SAPS options assessment commentary

### 5.4.1 Generation and storage

The assessment rationale for each of the generation and storage options is as follows, with their potential ability to meet the assessment criteria:

- **Generation using gas turbines or diesel (1.1):**

*Identified need (partially met)* - 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.

*Technical (not met)* – Significant constraints and barriers to deployment of multi-megawatt generation equipment 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, installing generators would result in an increase in fault levels which could exceed Code Limits under N and N-1 conditions

*Economic (not met)* – Costs of this type of generation appear much higher than the network alternatives. 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.

*Timing (not met)* - 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.

*Overall* – Generation using gas turbines or diesel (or other similar technology) is not a potentially credible option.

- **Generation using grid-scale solar and storage (1.2):**

*Identified need (not met)* – Reduces safety and reliability risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. Solar installations in EP provide a relatively small capacity. 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.

*Technical (not met)* – Significant constraints and barriers to deployment of multi-megawatt generation equipment in a dense urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). Energy and reliability requirements may be difficult to meet using solar generation alone without oversizing the batteries.

*Economic (not met)* - Costs of this type of generation appear appear much higher to the network alternatives. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated/stored (and other services) through the market. The scale of estimated capital costs illustrates the quantum of additional capital costs compared to a network solution and this will lead to a much higher cost per MWh compared to the preferred network solution.

*Timing (not met)* - 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.

*Overall* – Generation using grid connected solar and battery storage (or other similar technology) is not a potentially credible option.

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

*Identified need (not met)* – Reduces safety and reliability risks of running old plant beyond life. Presently there are no industrial HV customers supplied by EP. It's unlikely that this number of industrial customers are 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.

*Technical (partially met)* - This type of standby generation technically feasible within existing industrial sites but would face planning and technical constraints particularly due to the current high fault levels at EP.

*Economic (not met)* – The economic viability of this model is dependent on the customer uptake and the load of those customers wishing to participate. Smaller load customers will require more installations for the same delivered response. 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.

*Timing (not met)* – 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.

*Overall* – Standby generation at customer premises is not a potentially credible option.

- **Storage only using grid-scale batteries (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* – Generation using grid connected battery storage (or other similar technology) is not a potentially credible option.

### 5.4.2 Demand management

Under this non-network assessment scenario, 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 is considered with embedded generation of 10 MVA.

The assessment rationale for the demand management/efficiency options is as follows, with their potential ability to meet the assessment criteria:

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

*Identified need (not met)* - 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.

*Technical (partially met)* – 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 is less than one half of current maximum demand, which is not able to be met by an improvement in power factor alone.

*Economic (not met)* - This solution could be cost-effective however the estimated cost of embedded generation is unlikely to be commercially viable.

*Timing (partially met)* - Due to the required demand reduction this option is unlikely to be completed in the timeframe required.

*Overall* – Power factor correction is not a potentially credible option.

**Customer solar power and storage systems (2.2)**

*Identified need (not met)* – As noted in section 5, solar PV customer premises in the EP supply area is around 16% with 4.3 MW of installed capacity. Approximately 2,000 additional EP supply area customers (58% of remaining customers) would need to have a 5 kW solar PV system installed to provide 10 MW capacity. This rate of take-up is considered to be achievable, but not within the timeframe. This solution also fails to reduce cost and complexity of connection for new developments.

*Technical (partially met)* – This option is technically feasible and the technology is well understood and tested. Two 10 MVA of embedded generations would face planning and technical constraint.

*Commercial (partially met)* – This option is commercially feasible as the appetite for customers to take up solar PV is high and the opportunity for customers to take up electric vehicles and behind the meter storage is emerging with aggregator functions starting to develop in the market.

*Economic (partially met)* – 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 economically viable.

*Timing (partially met)* – There is uncertainty over whether this could be achieved given the large number of customers that would need to install solar by the required timeframe.

*Overall* - Customer solar power and storage systems is not a potentially credible option to be used for network support purposes in aggregate.

- **Broad-based demand response (2.3)**

*Identified need (not met)* – The assessment for this option is similar to Option 2.2. Each of JEN's approximately 4,000 customers at EP would have to reduce consumption by approximately 32% during the summer peak period to achieve a 6.4 MVA reduction (6.4 MVA / 20.4 MVA = 32%). This scale of reduction is considered unrealistic even if accompanied by subsidies to consider doing this.

*Commercial (partially met)* – To implement a broad-based demand response program across the supply area, each of JEN's customers would need to be approached to participate in a managed program to reduce consumption. There are a relatively large number of commercial and industrial customers in the supply area that could be well equipped to provide such a service to reduce their demand, and the demand response could be expanded to cover residential demand to allow some level of control over air-conditioning demand at times of peak, both using financial incentives program.

*Technical (partially met)* - This option is technically feasible and the type of efficiencies required achievable if sufficient customers are willing to invest in such measures. Two 10 MVA of embedded generations would face planning and technical constraint.

*Economic (partially met)* - Unclear that this is commercially feasible. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable.

*Timing (partially met)* - This type of mass action would be difficult to promote and implement and unlikely to be completed in the timeframe required

*Overall* – Broad based demand response is not a potentially credible option, particularly in the initial years of the 10-year period.

- **Targeted demand response (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* – Targeted demand response is not a potentially credible option, particularly in the initial years of the 10-year period.

# 6. Conclusion and next steps

## 6.1 Conclusion

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

In addition, the analysis demonstrates that there are no combinations of non-network 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 intends to publish the DPAR for consultation by 19 January 2026.