Jemena Electricity Networks (Vic) Ltd

East Preston (EP) Conversion Stage 7 and 8

RIT-D Stage 2: Draft Project Assessement Report

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East Preston (EP) Conversion Stage 7 and 8
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Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the north-west 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.

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 identifying the credible option that maximises the present value of the net economic benefit (the preferred option).

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).

RIT-D process

Distribution businesses are required to undertake the Regulatory Investment Test for Distribution (**RIT-D**) consultation 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 NEM, as well as that arising from changes in Australia's greenhouse gas emissions (the preferred option).

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[1].

[1] AER 2024 RIT and APR cost thresholds review final determination (November 2024).

For stage 1 of the RIT-D process, JEN consulted on the credibility of potential non-network and stand-alone power system (**SAPS**) options as alternatives or supplements for the network options being considered. A Notice of Determination[2] for the EP Conversion Stage 7 & 8 was published which determined whether the proposed network solutions to address the need could be changed in scope or otherwise altered in response to a non-network or SAPS solution. No submissions were received on the Notice of Determination.

We have now proceeded to stage 2 of the RIT-D process and have published this Draft Project Assessment Report (**DPAR**) because the cost of the most expensive credible network option to address the identified need is greater than the trigger threshold of $14 million[1.] . This report quantifies the reliability of supply risks associated with asset condition base failure at EP zone substation. This DPAR analyses alternative credible options for economically mitigating those risks, and identifies the preferred option at this stage of the draft RIT-D assessment.

Options considered

The Notice of Determination Report presented network options designed to address the identified need for continuing to reliably meet the supply reliability risk of customers in the East Preston supply area. The credible options considered were:

- Option 1 – Base case “Do Nothing”;
- Option 2 – Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN);
- 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); and
- Option 5 – Undertake like for like replacement of the remaining EP 6.6 kV distribution assets.

The Notice of Determination also considered the credibility of potential non-network and SAPS options as alternatives to, or supplements for the identified network options to meet the identified need. The assessment within the Notice of Determination 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, leaving only options 1, 2, 3, 4 and 5 for assessment in this DPAR. No submissions were received on the Notice of Determination.

Proposed preferred option

The preferred option is that option which maximises the present value of the net economic benefit, weighted across a set of reasonable state-of-the-world scenarios. Table 1–1 below summarises the cost-benefit analysis for each option, based on the weighted outcome across the three scenarios considered.

Table 1–1: Summary of cost benefit analysis (PV, $M, 2025), weighted outcome

Present Value	Option 1	Option 2	Option 3	Option 4	Option 5
Capital costs	0	42	50	50	70
Avoided expected unserved energy (EUE)	0	321	306	314	288
Net Market Benefits (NPV)	**0**	**278**	**256**	**264**	**218**

The option that has been found to maximise the present value of net market benefits, both on a weighted basis and in each scenario, is Option 2. The robustness of this conclusion has been tested under a range of sensitivities.

[2] RIT-D Stage 1: Notice of Determination Report, Jemena, 27 October 2025.

In each case, Option 2 was confirmed to provide positive economic benefits and is the highest ranked option. Option 2 therefore satisfies the requirements of the RIT-D and is the proposed preferred option at this draft stage.

It should be noted that the preferred option is expected to generate additional benefits which were not quantified as part of this appraisal, and further support the case for prompt investment:

- Safety - Jemena did not undertake a quantified assessment of the safety benefits of each option as the likelihood and impact of major safety events cannot be reliably quantified without introducing speculative assumptions. In line with common practice within the electricity sector, JEN has qualitatively considered how each credible option reduces asset failure risk and operational hazards. Although unquantified, these safety benefits are expected to be significant and will not likely affect the ranking of options.
- Secondary asset failure - the supply risk associated with the replacement of secondary asset such as relays was also not quantified, as it was considered second order, and unlikely to affect the ranking of options.
- Reduction in network losses - the reduction in network losses associated with converting the old 6.6 kV network and to a 22 kV network was not quantified. This benefit is also expected to be significant, but was not quantified given the proportionality test – the case for investment was made without consideration of these benefits.

The scope of the proposed preferred option involves:

- **EP Conversion Stage 7:** Continue with the feeder conversion works to transfer load from EP ‘B’ to EPN. This involves establishing 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. The construction work is planned to be completed by 2028. It will involve the conversion of feeders and distribution substations from 6.6 kV to 22 kV.
- **EP Conversion Stage 8:** Install a 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, all load on EP ‘B’ will have been transferred to EPN to allow the decommissioning and removal of all EP ‘B’ assets. EP zone substation will then be fully decommissioned by 2030.

The capital cost of Option 2 is approximately $48.4 million (real 2025). The assessment finds that the optimal completion date for the entire option is by 2030.

Submission and next steps

We now invite written submissions on this report from interested stakeholders identified as “East Preston (EP) Conversion Stage 7 and 8 RIT-D”.

All submissions and enquiries should be directed to:

Hung Nguyen
Network Planning Team Leader
Email: PlanningRequest@jemena.com.au

Submissions should be lodged with us within 6 weeks after the publication of this report, on or before 3 April 2026. All submissions will be published on JEN’s website. If you do not wish to have your submission published, please indicate this clearly in your submission.

Following consideration of any submissions on this DPAR, JEN will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will be the final stage of the RIT-D process.

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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 long-term, probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Limitation	Refers to a constraint on a network asset's ability to transfer power.
Load-at-risk	The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions.
Jemena Electricity Networks (Vic) Ltd (JEN)	One of five licensed electricity distribution networks in Victoria, Jemena Electricity Networks (Vic) Ltd 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 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 prescribed limit, in the National Electricity Market (NEM).
Stand Alone Power System (SAPS)	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 according to normal daily network operation practices
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 Jemena's Electricity 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

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CPI	Consumer Price Index
DAPR	Distribution Annual Planning Report
DPAR	Draft Project Assessment Report
EP	East Preston Zone Substation
EPN	East Preston North Zone Substation
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
FPAR	Final Project Assessment Report
HV	High Voltage
JEN	Jemena Electricity Networks (Vic) Ltd
kV	Kilo-Volts
LV	Low Voltage
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
N	System normal condition
N-1	Single contingency condition
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
O&M	Operations and Maintenance
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
SAPS	Stand-alone Power System
VCR	Value of Customer Reliability

1. Introduction

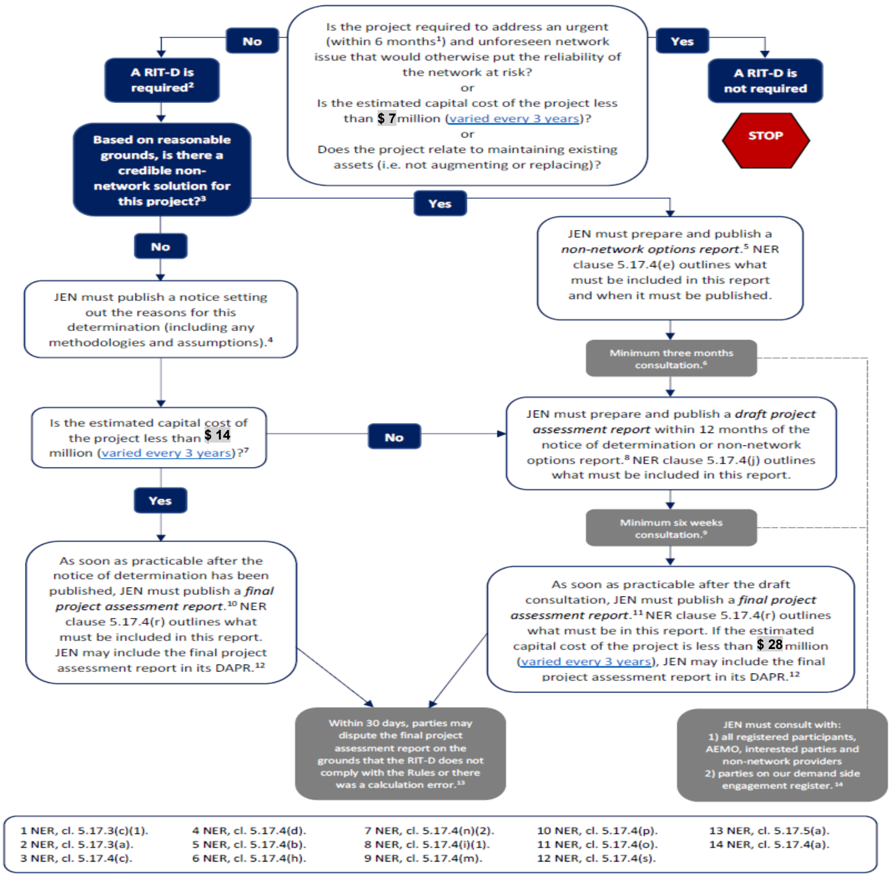
This section outlines the purpose of the Regulatory Investment Test for Distribution (**RIT-D**) in relation to the East Preston supply area, and the structure of this Draft Project Assessment Report (**DPAR**).

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**), to identify the investment option that best addresses an identified need on its 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).[3] The identified need in this RIT-D is to maintain the reliability of supply in the East Preston supply area, whilst accommodating new customer connections and growth in customer maximum demand.

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[4]. JEN has identified four potential credible network options. The capital cost of each of the credible options to address this identified need within the East Preston supply area is above this threshold and so has triggered the requirement for a RIT-D. The RIT-D process is summarised in Figure 1–1.

Figure 1–1: The RIT-D Process



[3] 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.

[4] Source: AER 2024 RIT and APR cost thresholds review final determination (November 2024). The RIT-D also applies where the identified need is reliability corrective action.

JEN must consider non-network and stand-alone power system (**SAPS**) options when assessing credible options to address the identified need. As part of the first stage of the RIT-D process for the East Preston supply area, a Notice of Determination report was published which determined that a none of the non-network or SAPS options may be potentially viable to address the identified need. We also received no submissions on the Notice of Determination. JEN has now prepared this DPAR to commence the second stage of RIT-D consultation.

1.2 Structure of this report

The objective of this DPAR is to present the results of an economic evaluation that assesses the credible options for addressing the identified need within the East Preston supply area, and to identify the proposed preferred option.

The contents of this DPAR is set out as follows:

- Section 3 articulates the identified need in relation to the East Preston supply area;
- Section 4 sets out the key assumptions relating to the identified need;
- Section 5 provides a summary of, and commentary on, the submissions on the options screening report (noting that no submissions were received);
- Section 6 sets out the credible options assessed to address the identified need;
- Section 7 summarises the assessment method applied;
- Section 8 presents the net present value assessment results for the credible options assessed; and
- Section 9 details the technical characteristics, costs and optimal timing of the proposed preferred credible option, and next steps.
- Appendix A sets out the RIT-D compliance checklist.

2. Background

This section provides an overview of the Preston supply area; describes the general arrangement of Preston and East Preston network supply areas; provides a brief overview of the network limitations; and highlights the projects (staging of works) that have been completed and committed for the East Preston conversion program. The assessment is based on the latest 2025 Load Demand Forecast.

2.1 Network Supply Arrangements

Jemena Electricity Networks Vic Ltd. (JEN) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. JEN service area covers 950 square kilometres of northwest greater Melbourne and includes some major transport routes and the Melbourne International Airport, which is located at the approximate physical centre of the network. The network comprises over 6,800[5] kilometres of electricity distribution lines and cables, delivering approximately 4,374 GWh of energy to around 375,000 homes and businesses for several energy retailers. The network service area spans 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.

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 failure and risk of step and touch potentials.

In addition to the addressing the safety issues, the Preston area network development plan focused on addressing the following needs:

- maintain supply availability and reliability to customers with a long-term strategy to address the deteriorated condition of primary, secondary and distribution plant at EP zone substations (replacement expenditure, or repex); and
- meet the supply capacity shortfall forecast for the Preston and adjacent zone substation supply areas due to increased load demand (augmentation expenditure, or augex).

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. Distribution at 6.6 kV has significantly lower transfer capacity than distribution at 22 kV and hence more feeders are required, resulting in overhead network congestion in the road reserves. There is limited opportunity 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 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. 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 issues, JEN embarked on a program of work to convert the P and EP distribution network from 6.6 kV to 22 kV, which formed the Preston conversion program. 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 and establishing two new 66/22 kV zone substations Preston (PTN) and EPN respectively on the same sites.

[5] Does not include low voltage services.

The Preston conversion program was designed to follow a particular sequence, as described in Table 2-1, to deliver the optimal outcome for JEN's customers. The timing and scope of conversion stages have undergone minor changes since the program commenced in 2008.

Table 2-1: Preston conversion program objective

Objective	Conversion Stage(s)
(1) Transfer as much load as possible away from P/EP 6.6 kV to nearby CS/CN/NH 22 kV zone substations	P Stages 1, 2 and 3, and EP Stages 1 and 2
(2) Establish 22 kV supply capacity (EPN[6]) within the P/EP area to enable converting / transferring load away from P to continue	EP Stage 3
(3) Transfer all load away from P and retire P zone substation 6.6 kV assets	P & EP Stage 4 and P Stage 5
(4) Add additional 22 kV supply capacity within the P/EP area to enable converting / transferring load away from EP to continue, and enable some load to be transferred back from CS and CN to address capacity constraints	P Stage 6
(5) Transfer all load away from EP and retire EP zone substation 6.6 kV assets to 22 kV	**EP Stages 5, 6, 7 and 8**

To date with the first four objectives being completed, the program is currently focused on delivering the fifth objective with EP Stage 6 currently in the delivery phase. All the remaining P feeders have been transferred away from the old P zone substation allowing the decommissioning and construction of a new 66 kV/22 kV zone substation called Preston (PTN) at the existing Preston site, which was commissioned June 2020.

The fifth and last objective of the program has started, with EP Stage 5 completed in June 2022 and EP Stage 6 completed in December 2025 with EP 'A' switch house decommissioned in December 2023.

Based on the 2025 Load Demand Forecast, EP 'B' experiences maximum demand during winter under 50% probability of exceedance (PoE) and under 10% PoE, with:

- 50% PoE maximum demand forecast to increase from 18.9 MVA in 2025 to 22.2 MVA by 2035.
- 10% PoE maximum demand forecast to increase from 23.9 MVA in 2025 to 27.8 MVA in 2035.

2.2 General Arrangement

Figure 2-1 below shows the Preston and East Preston supply areas and surrounding suburbs prior to the works for the Preston conversion program. It indicates the different voltage levels and other distribution businesses' networks.

[6] New East Preston zone substation (EPN) established in 2015 operating at 66 kV/22 kV.

Figure 2-1: Original Preston and East Preston supply area (2008)

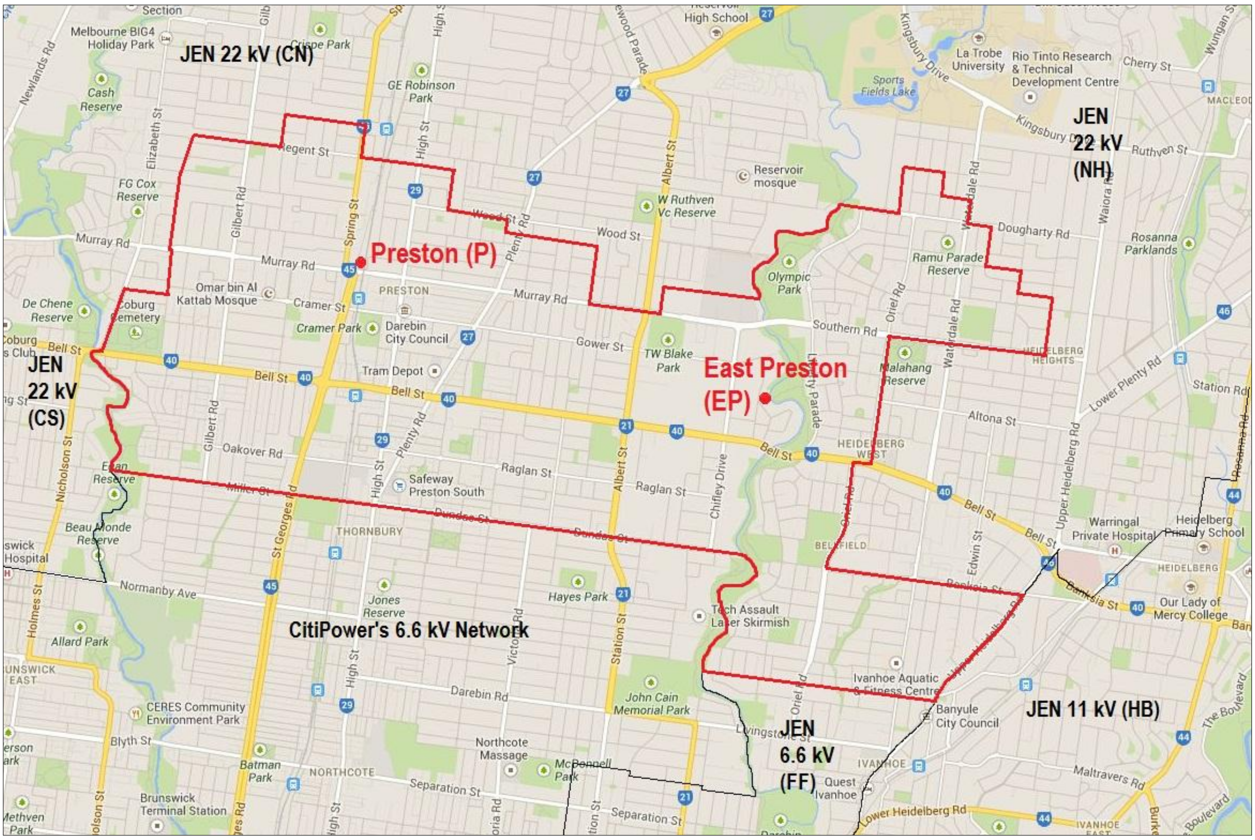
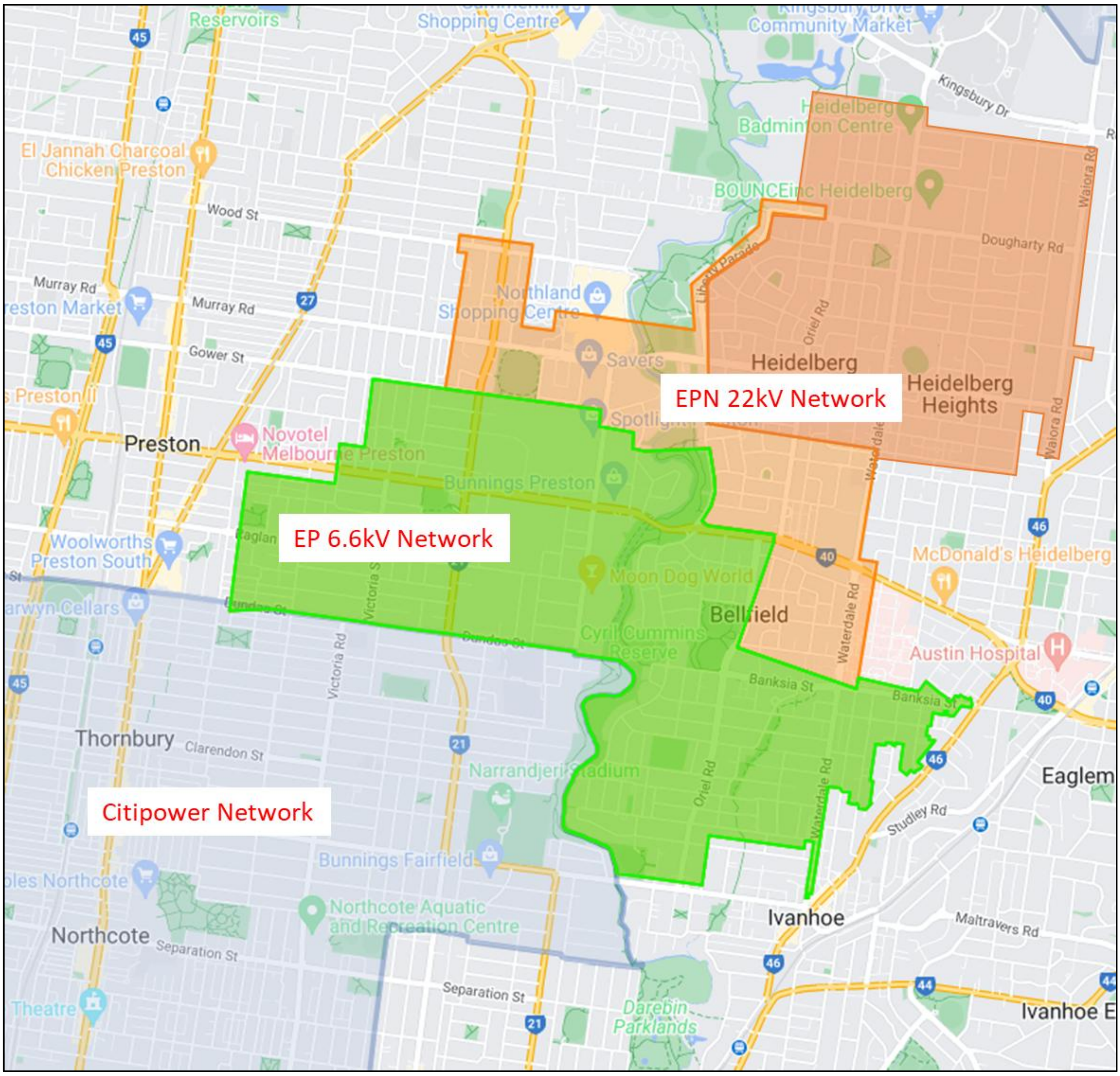


Figure 2-2 Forecast East Preston supply area (December 2025)



3. Identified Need

JEN has identified the present East Preston distribution network as a priority for investment based on three key 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 East Preston area by reducing the cost and complexity of connection for new residences and new businesses (Customer Connections).

Each of these are addressed in turn below.

3.1 First Identified Need – Safety

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

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

The deteriorated condition of the assets, along with detailed discussions on the need to retire and replace the major primary and secondary assets at EP Zone Substation, are documented in the following JEN reports:

- Primary Plant Asset Class Strategy (document number ELE-999-PA-IN-008)
- Secondary Plant Asset Class Strategy (document number ELE-999-PA-IN-010)
- Distribution Asset Class Strategy (document number ELE-999-PA-IN-007)

The safety risk at EP zone substation are as a result of the following:

- Deteriorating poor condition of the switchgear;
- The switchboard is non-arc fault contained;
- There is no Neutral Earthing Resistor (NER) at the zone substation and non-Common Multiple Earthing Neutral (CMEN) on the distribution network; and
- The secondary equipment (e.g. relays) are well beyond their economic life and are installed on asbestos type panels.

3.1.1 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 Second Identified Need – 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;

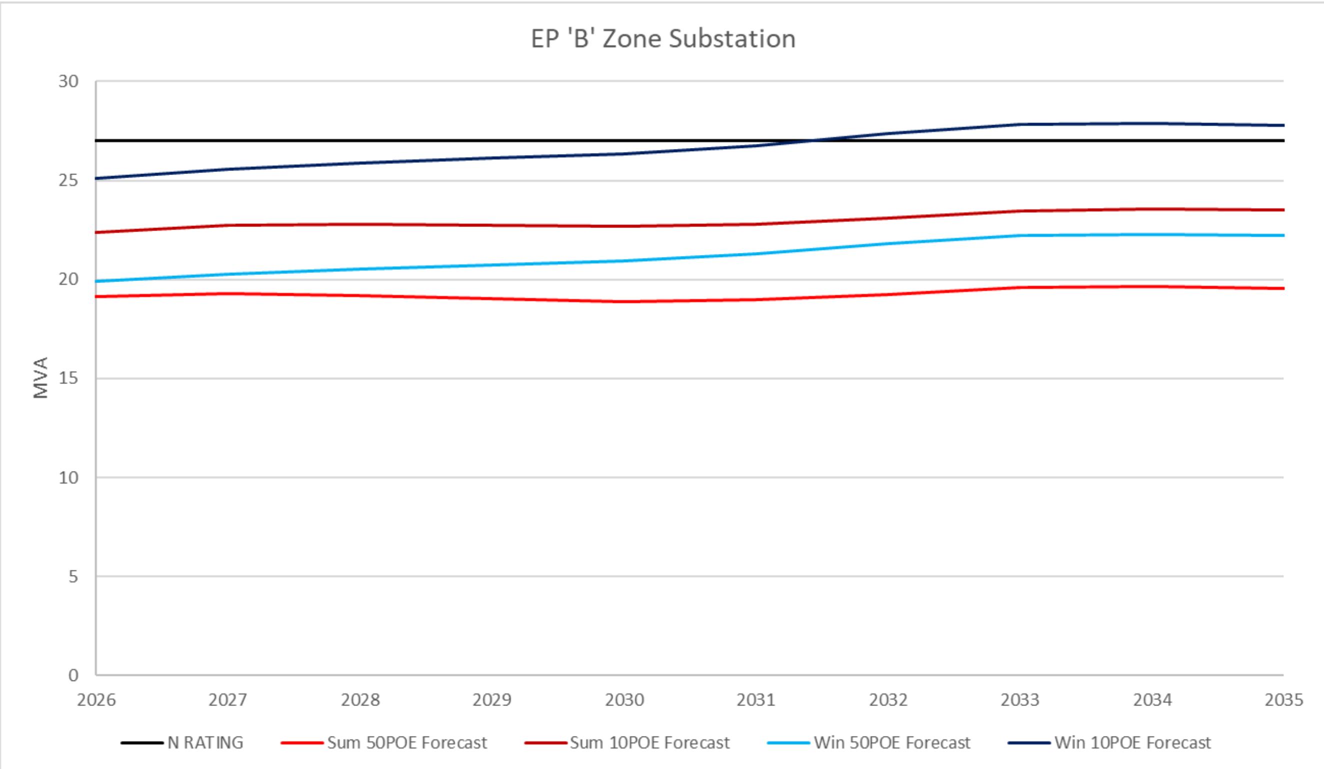
- Provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options; and
- Estimates expected unserved energy which is defined in terms of megawatt hours (MWh) per annum and expresses this economically by applying a value of customer reliability ($/ MWh).

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 loads at risk under system normal conditions and if any single item of equipment was out of service or credible contingency conditions (i.e., N-1 condition).

An option is viable where the annualised cost of expected unserved energy at risk exceeds the cost of augmentation. The expected unserved energy increases in circumstances where there is a deterioration in supply reliability due to capacity shortfall and limited ability to transfer capability during times of peak demand under single contingency conditions. The risk of unserved energy depends on the design and capacity of the current network, its transfer capacity and the forecast load, which is discussed below.

The demand forecast for EP 'B' switch-house is shown below in Figure 3–1. The forecasts for the supply area show that the maximum expected demand is 23.9 MVA for EP 'B' for the winter 10% PoE in 2025. For EP 'B' the forecast load demand is increasing between 2026 and 2035. This forecast includes known spot loads where a customer has made an 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. The condition of the No.3 and No.4 transformers are in such poor condition that they must be retired, leaving EP 'B' effectively reliant on a single transformer (No. 2) to supply the load under system normal conditions. 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 presents 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 due to a lack of spare capacity.

Table 3-1: Feeder Forecast Utilisation

Feeder	2026	2027	2028	2029	2030	2031
EP34	99%	102%	103%	105%	107%	108%
EP36	95%	97%	98%	98%	99%	100%
EP37	89%	90%	90%	89%	88%	89%

3.2.1 Credible Solution Requirements

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario and meet EP 'B' zone substation demand forecast.

3.3 Third Identified Need – Customer Connections

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 has been constructed 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 organisations 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.

JEN is under a regulatory obligation to make offers to connect customers. 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.

3.3.1 Credible Solution Requirements

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

4. Assumptions relating to the identified need

In line with the purpose of the RIT-D, as outlined in clause 5.17.1 (b) of the NER, an investment to address the identified need relating to the reliability of supply risks at EP, would be expected to result in an increase in net economic benefits. This net economic benefit increase is driven by avoiding EUE (reduced involuntary load shedding) as maximum demand at EP increases. The present value of these net economic benefits has been compared to the present value of the costs of each credible option to determine the net benefit – see section 8. The ranking of options by net benefit is then used to identify the preferred option.

JEN applies a probabilistic planning method that considers the likelihood and severity of critical network conditions and outages, based on the forecast demand and associated capacity ratings, asset condition and the associated asset failure rates. The method compares the forecast cost to consumers of energy supply interruptions (e.g., when demand exceeds available capacity) against the proposed investment cost to mitigate the EUE. The annual cost to consumers is calculated by multiplying the EUE by the locational value of customer reliability (VCR). This is then compared with the annualised investment cost, to identify optimal timing.

To ensure the net economic benefit is maximised, an investment will only be undertaken if the present value of benefits outweigh the present value of costs of the proposed investment to reduce the unserved energy. Investments are not always economically feasible and this planning method therefore carries an inherent risk of not being able to fully supply demand under some possible (but rare) events, such as a network outage coinciding with peak demand periods. The probabilistic planning method that we apply is further detailed in our Distribution Annual Planning Report (**DAPR**).

The key assumptions that have been applied in quantifying the East Preston supply area limitations for this DPAR are outlined in this section, and include:

- Network asset ratings; and
- Network outage rates.

4.1 Network Asset Ratings

4.1.1.1 Primary Plant assets

Although established in the 1920's, EP Zone Substation underwent extensive refurbishment in the early 1960's. 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 (ACS) and with the application of JEN's Condition Based Risk Management (CBRM) modelling, using inputs from condition testing and monitoring, the major equipment (primarily the circuit breakers and buses) at EP are assessed to be at a 'high' risk of failure.

The deteriorated condition of the assets and detailed information on the need to retire and replace the major primary assets at EP Zone Substation are documented in the following JEN Asset Class Strategy documents (ACS):

- Primary Plant Asset Class Strategy (document number ELE-999-PA-IN-008).

JEN has developed an indicator of asset condition referred to as a 'health index' which takes into account asset age and condition as revealed by condition monitoring tests. This is a practice adopted by leading asset managers in Australia and overseas referred to as Condition Based Risk Management (CBRM).

The CBRM Health Index is a numeric representation of the condition of each asset. Essentially, the health index of an asset is a means of combining information that relates to its age, environment and duty, as well as specific condition and performance information to give a comparable measure of condition for individual assets in terms of proximity to end of life (EOL) and probability of failure. The concept is illustrated schematically in Figure 4-1. A health index exceeding 7 represents serious deterioration with a high risk of failure.

Figure 4-1: CBRM Health Index

Condition	Health Index	Remnant Life	Probability of Failure
Bad	10	At EOL (<5 years)	High
Poor		5 - 10 years	Medium
Fair		10 - 20 years	Low
Good	0	>20 years	Very low

Coupled with risk assessments of the consequences of failure, JEN develops a prioritised asset replacement program using the CBRM tool. The program represents the forecast asset replacement requirements in the next five years. JEN notes this asset replacement approach provides the best balance between operational risk, customer supply reliability and ensuring network costs are minimised.

Switchgear

JEN's CBRM modelling was introduced in 2014 for switchgear assets and is used to assist in the development of asset investment plans using existing asset data and other information.

The CBRM modelling indicates that on average the health index results (as of 2024) for most of the circuit breakers and buses at EP are greater than 7 and will have experienced further deterioration by 2028. The result indicates that the remaining 6.6 kV circuit breakers and 6.6 kV buses at EP are in poor condition with an expected remnant life of less than 5 years with a high probability of failure, which means that all circuit breakers are already operating beyond their regulatory life of 45 years. In this condition the probability of failure of the switchgear at EP is significantly raised and the rate of further degradation will be relatively rapid[7]. This modelling result is consistent with the defects and issues identified at EP zone substation in recent years, which are further detailed below. The health index and consequent risk of failure of assets at EP zone substation will continue to increase if no action is taken.

A summary of the CBRM results at EP 'B' switch-house are provided in Table 4–1.

Table 4–1: CBRM Result Summary EP 'B'

Equipment	No. of equipment	Average Age (years)	Expected Life (years)	Health Index forecast (derived from CBRM)	
				2024	2028
6.6 kV bus tie CB	2	56	50	7.0	7.9
6.6 kV feeder and cap bank CB	11	53	45	9.0	10.6
6.6 kV transformers CB	4	56	48	8.4	9.6
6.6 kV buses	3	56	50	9.2	10.2

Bushing replacements were undertaken at EP zone substation, with spares taken from P zone substation and Pascoe Vale (PV) zone substation, to replace 6.6 kV CB bushings showing a high level of insulation degradation. There are no spares available for replacement of faulty bushings or bushings with high Dielectric Dissipation Factor (DDF) readings at EP zone substation. This is further supported by independent tests undertaken, which demonstrated that the DDF values on section of the EP switchgear of up to and exceeding 5%, which means the switchgear is severely degraded.

[7] JEN Primary Plant Asset Class Strategy (document number ELE-999-PA-IN-008).

The bushing construction is resin bonded paper with the majority of the bushing length exposed to air. Once there is moisture ingress the bushings cannot be repaired. Bushings with high DDF readings indicate current leakage to earth due to moisture ingress in the insulating medium, which then leads to thermal runaway, and can cause catastrophic insulation failure and fire. In the event of a circuit breaker bushing failure at EP there are no spares available to reinstate the circuit breaker or rebuild the bus work this is due to the equipment being no longer supported by manufacturer.

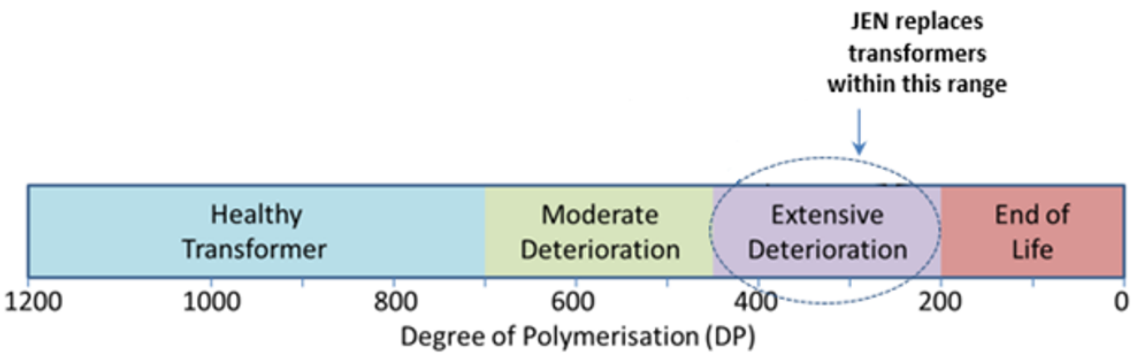
Transformers

Currently, the accepted method of life assessment for transformers is Degree of Polymerisation (DP) which quantifies transformer paper condition and strength. A DP value of between 200 and 450 signifies that transformer insulation has experienced extensive deterioration and should be scheduled for replacement before failure occurs. The tensile strength of paper in this condition is approximately 20% of fresh paper and is considered to be the end of life for the transformer.

DP values can either be measured directly by taking samples of the winding paper or indirectly through measurement of furan levels in the oil or by conducting PDC/RVM (Polarising, Depolarising Current method/Recovery Voltage Method). The DP value derived by measurement of furan levels in oil is less accurate and typically results in DP values twice that of testing directly on paper. DP values derived from PDC/RVM testing are more accurate than the value derived from furan levels but still not as accurate as paper testing. Furthermore, the DP value varies greatly depending on the location of the paper tested within the winding. It is expected to be lowest in the centre of the winding where it is hotter. Replacing or refurbishing oil also reduces furan levels and results in an apparent improvement in the DP values.

The calculated DP from the PDC/RVM analysis done in 2024 for EP transformer No.2, 3 & 4 are provided in the table below. The results do not account for the DP value variation throughout the winding, therefore the actual DP value is now expected to be 700, 600 & 650 for transformers EP No.2, 3 & 4 respectively, which indicates the transformer are within moderate deterioration. This is further illustrated in Figure 4-2 below.

Figure 4-2: Transformer Condition Scale



The transformers at EP zone substation undergoes a condition based monitoring regime, including the DP assessment outlined above. The current Condition Monitoring Index for the transformer at EP is shown in Table 4–2 and demonstrates that EP transformer No.3 and No.4 are within the extensive deterioration range and in need of retirement. However, EP transformer No.2 is relatively new (16 years old) and has a good health index, therefore it is planned this transformer will be retained as a spare emergency transformer on the JEN network.

Table 4–2: CBRM Result Summary EP (transformer)

Equipment	Age (years)	Health Index forecast (derived from CBRM)	
		2024	2028
EP transformer No.2	17	1.6	2.0
EP transformer No.3	64	7.6	8.5

EP transformer No.4	65	7.3	8.1

4.1.1.2 Secondary Plant assets

In addition to the primary plant assets' deteriorating condition, the secondary plant (e.g. protection relays, CTs and VTs) at EP zone substation is well over 50 years old and installed on asbestos type panels. The majority of the protection relays (such as feeder and transformer protection relays) have reached the end of their useful engineering life and are prone to age related performance deterioration such as drift, which makes the relay operation inconsistent and unreliable.

The electromechanical protection relays at EP zone substation are no longer supported by the manufacturer and there are no spare relays available. Furthermore, the electromechanical relays do not provide any self-diagnostics or failure monitoring. Consequently, relay failures can remain undetected and as a result, there is a risk that primary plant (e.g. transformers and switchgear) will remain unprotected without knowledge of their failure.

Protection relays are designed to isolate a fault as quickly as possible to provide protection to primary plant, personnel and the environment. The failure of a protection relay (e.g. feeder protection) to clear a fault will result in the operation of its backup protection (e.g. 6.6 kV bus overcurrent), which is designed to isolate the fault more slowly than the primary protection and will also isolate all feeders connected to this bus rather than just the faulted feeder. The additional time required to clear the fault will increase the risk and severity of damage to primary plant as well as resulting in a much greater impact on the number of customers being off supply. Given the higher fault levels at 6.6 kV voltage, this will also expose the primary plant equipment to heightened mechanical and electrical stress, which will increase the risk of failure.

It is expected that maintenance costs for repair and condition monitoring at EP zone substations will increase over the next 10 years as the assets reach end-of-life. Further details on the deteriorated condition of secondary assets are documented in the JEN Secondary Plant Asset Class Strategy (document number ELE-999-PA-IN-010).

4.2 Network Outage Rates

The network outage rates applied in a probabilistic economic planning assessment can have a large impact on the selection of the preferred option and the optimal timing of that option. JEN has considered the potential failure of transformer, bus and circuit breaker in its assessment of the options.

4.2.1.1 EP transformer and switchgear failure rates

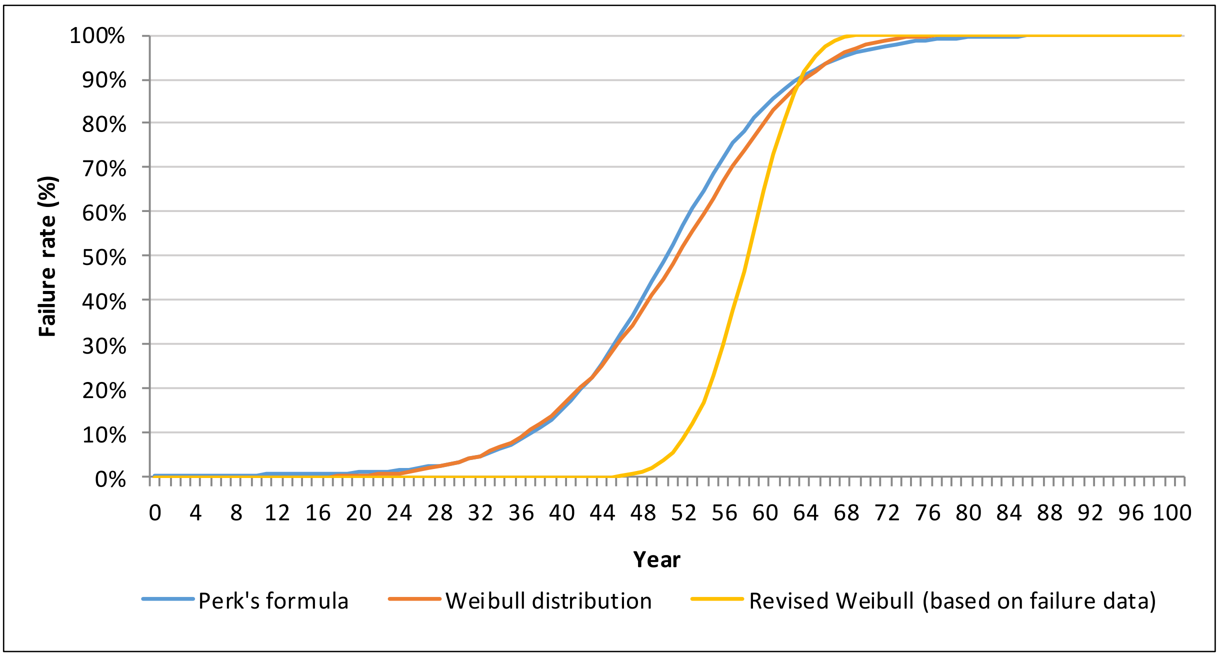
The probability of failure of the EP transformers and switchgear is based on predictions of remaining life taken from our CBRM assessments. Distribution curves were fitted to the data to establish a probability of failure curve. This was then compared to Perk's formulae as a sense check[8].

When considering the switchgear at EP, it was possible to correlate a good fit with a Weilbull failure curve based on the condition monitoring results and the output of CBRM's health index for the EP switchgear. Adding data for similar switchgear at other zone substations did not provide a better distribution fit and were discarded.

Figure 4-3 shows the cumulative distribution curve for the EP switchgear probability of failure. It shows the Perk's formula distribution, the general Weibull distribution for circuit breakers, and the revised Weibull distribution based on the EP switchgear. As expected, the revised curve is steeper than the others, as the data does not contain any failures to date, whereas the other curves represent a more general failure rate for the 6.6 kV switchgear fleet. With the revised curve in the correct relationship to the other curves, we accept it is fit for use as a failure curve for the EP switchgear.

8 Perk's formula is an exponential distribution optimised for electrical assets, primarily transformers.

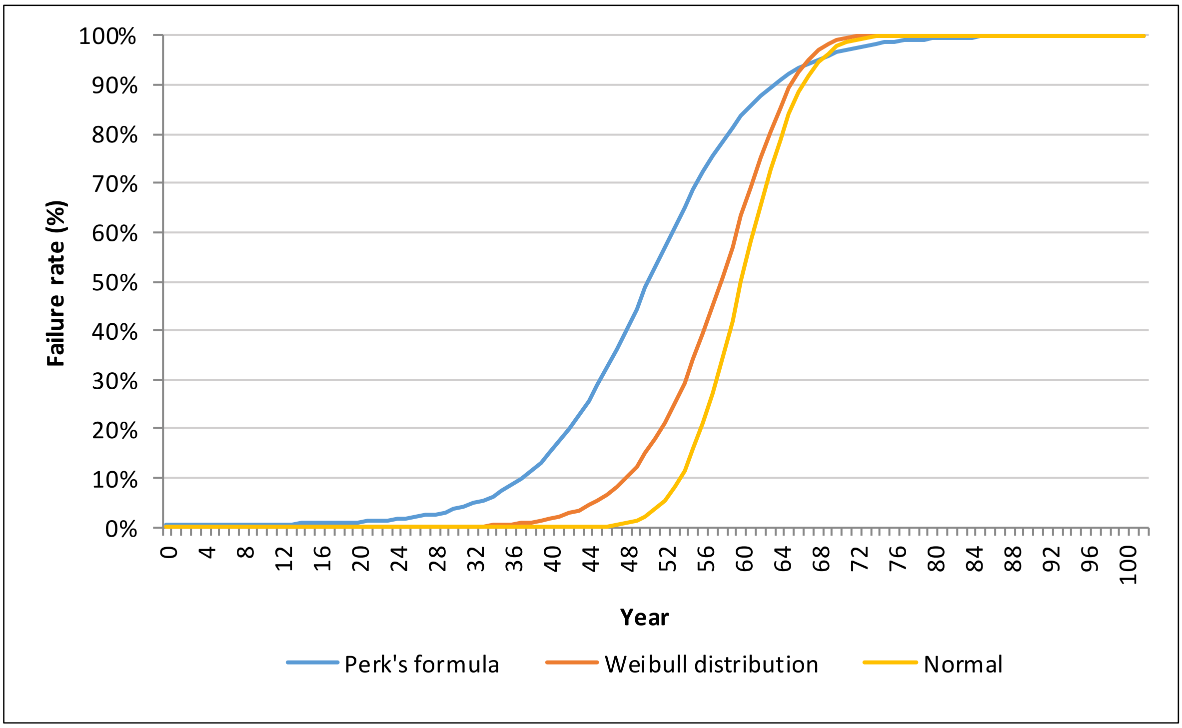
Figure 4-3: EP switchgear failure curve



JEN also reviewed the CBRM data for the EP transformers to identify the most appropriate failure curve for the transformers. There was only a small data set available for this analysis, and based on the data available the most appropriate failure curve for the EP transformers was a Normal distribution, noting that the software used in the curve fitting did not converge on the preferred Weibull distribution.

Figure 4-4 shows the cumulative distribution curve for EP transformer probability of failure. It shows the Perk's formula distribution, the general Weibull distribution for transformers, and the Normal distribution based on the EP transformers' forecast remaining life. As expected, the revised curve is steeper than the others, as the data does not contain any failures to date, whereas the other curves represent a more general failure rate for the transformer fleet. With the revised curve in the correct relationship to the other curves, we accept it is fit for use as a failure curve for the EP transformers.

Figure 4-4: EP transformer failure curve



4.2.1.2 Probability of EP bus unavailability

The probability of failure of the EP buses was developed based on historical equipment failure data collected from the JEN network and other electricity networks with the same or similar equipment type. Failure was defined as any functional failure, ranging from mechanism failure to insulation failure.

The forecast probability of explosive failure of a section of bus, a circuit breaker or a cable termination resulting in a fire and extensive damage to the entire switchboard of 1 in 30 years is based on an actual event that occurred on JEN's network at Flemington (FT) zone substation over 30 years ago with the same type of switchgear. Although JEN has not been able to find details of this event, there are still some photos of this event, which shows the 3 panels of the switchboard were destroyed because of a catastrophic circuit breaker failure. Consistent with the CBRM model output which show the condition of the bus and circuit breakers seen from condition monitoring and test results are well deteriorated, the following probability and assumptions have been applied in the economic assessment.

- Probability of a bus failure affecting multiple buses is 1 in 30 years.
- Repair / replacement time is forecast to be 6 weeks (repair) and 8 months (replacement). For this assessment, it is assumed that repair can be undertaken within 6 weeks.

There are three 6.6 kV buses on EP 'B', therefore the probability of bus unavailability is (1/30) x 3 x (6/52) = 1.15% pa.

In undertaking the cost benefit analysis, the key assumptions that have a relatively high uncertainty in the future are asset failure rate and maximum demand, which together determine the quantity (MWh) of the EUE. To account for this uncertainty and consistent with the AER's requirements for businesses to undertake sensitivity analysis[9], we adopted three future state-of-the-world scenarios, which each adopt different and consistent assumptions in relation to these two key variables. We discuss the details in sections 7.5 and 7.6.

[9] AER, Regulatory investment test for distribution, Application Guidelines, November 2024, section 3.8

5. Submissions on the Notice of Determination

This section summarises the consultation to date and the submissions received on the notice of determination report.

A RIT-D stage 1 consultation notice of determination was published on JEN's website on 27 October 2025. This report was prepared to present the potential credible options being considered and establish whether the proposed network solutions to address the need, could be changed in scope or otherwise altered in response to a non-network or SAPS solution. It was concluded from the analysis presented in that report that there are no potential credible non-network or SAPS option (or any combination of those options, or with a network option) that could address the identified need within the East Preston supply area.

Notwithstanding this analysis, JEN did not receive any submissions, nor any proposals for alternative non-network or SAPS solutions, during the stage 1 consultation period.

6. Options considered in the RIT-D

This section outlines the credible options that have been considered in the RIT-D, and outlines the proposed works associated with each credible option. The base case is established, to compare the net benefits of options identified.

As previously noted in this report, the works to address the identified needs in the East Preston area have already commenced. Works completed to date for the East Preston conversion program are shown in Table 6-1. EP Stage 6 has recently been completed and has been in-service since December 2025.

Table 6-1: Preston conversion program – completed works

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	Completed	Decommission of EP 'A' zone substation and install 2nd transformer at EPN zone substation

Prior to committing to the final stages to complete the East Preston conversion program (as described in Table 6-2), a review in 2024 was undertaken that resulted in a revision of the East Preston Area Network Development strategy that confirmed the plan and staging of the required works where JEN has identified four network options (in addition to the base case) that attempt to address the identified need:

- Option 1: Do Nothing (BAU);
- Option 2: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN);
- 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; and

In addition to Option 1 (the 'Do Nothing' option), Option 2 and Option 5 were assessed in the latest version of this network development strategy and are retained and reviewed within this latest revision. Two revised network options have also been considered with Option 3 and Option 4. These two options re-assess the optimal scope for the remaining East Preston conversion program based on the latest load demand forecast.

Table 6-2: East Preston conversion program – remaining works

Staging of works	In Service Year	Cost Estimate	Status	Anticipated Works
EP Stage 7	2028	$30.0M	Not Started	Conversion of EP feeders and distribution substations
EP Stage 8	2030	$18.4M	Not Started	Conversion of EP feeders, distribution substations and an isolated section of FF90 feeder. Decommission of EP 'B' Zone Substation

6.1 Option 1 - “Do nothing” option (base case)

The assessment of credible options is based on a cost-benefit analysis that considers the future expected unserved energy of each credible option compared with the base case, where no augmentation option is implemented.

Under this base case, the action required to ensure that loading levels remain within asset capabilities is involuntary load shedding of JEN’s customers. The cost of involuntary load shedding is calculated using the value of customer reliability (VCR) which, for the JEN, is currently $37,972/MWh (2025 $), as described in Section 7.1.2.

The ‘Base Case’ option gives the basis for comparing the cost-benefit assessment of each credible option. The base case is presented as a ‘Do Nothing’ option, where we would continue managing network asset loading and run the assets to failure through involuntary load shedding.

Since there is no augmentation associated with the base case (Do Nothing) option, this option assumes to generate zero capital cost.

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

As recommended in the East Preston Area Network Development Strategy paper, this continues the conversion of the East Preston area in stages from 6.6kV to 22 kV. Under this strategy, the next stage is EP Stage 7.

For this report, the remaining stages of the Preston Conversion Program are summarised below at a high level.

EP Stage 7: Continue with the feeder conversion works to transfer load from EP ‘B’ to EPN. This involves establishing 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. The construction work is planned to be completed by 2028. It will involve the conversion of feeders and distribution substations from 6.6 kV to 22 kV.

EP Stage 8: Install a 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, all load on EP ‘B’ will have been transferred to EPN to allow the decommissioning and removal of all EP ‘B’ assets. EP zone substation will then be fully decommissioned by 2030.

Table 6-3 shows the planned in-service year and cost estimate for the remaining stages of the East Preston conversion program under this option.

Table 6-3: Option 2 staging and costs

Stages	In Service Year	Cost estimate (Real 2025 $)
EP Stage 7	2028	$30.0M

EP Stage 8	2030	$18.4M

The remaining works for the program will address the following problems:

- Maintain supply reliability to customers supplied from EP by addressing the physical asset risk at EP zone substation;
- Reduce the personnel safety risk associated with equipment that are not built to current safety standards and the high probability of failure due to their deteriorated condition;
- Reduce the risk of step and touch potentials;
- Improved the transfer capability for the East Preston area and provide more effective supply restoration by enabling the existing feeder automatic circuit reclosers to be utilised; and
- Several 6.6 kV EP feeders in the area are forecast to be reaching its safe operating thermal limits and do not have transfer capacity under single contingency conditions.

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

This option re-assesses the optimal scope for the remaining Preston conversion program (Option 2).

Due to the relatively flat load forecast on EP zone substation over the next planning period post-2026, this option examines if continuing the remaining 6.6 kV to 22 kV conversion from EPN zone substation as part of EP Stage 7 can be replaced with a more cost-effective option. Essentially around 20 MVA of additional capacity is required after EP Stage 6 to continue with the conversion works to retire EP. Under Option 2, this is achieved by utilising the second transformer and 22 kV bus with minimal works to establish new 22 kV feeders from EPN zone substation−where the load centre is for EP to continue with the conversion works.

Instead of establishing supply from the second transformer at EPN zone substation and 22 kV bus, this option would require a minimum of two new 22 kV feeders from PTN (approximately 1.3km and 1.8km of new underground cable for each feeder respectively). This option will also involve re-configuring existing feeders EPN-035, EPN-033 and further extending EPN-033 and PTN-014 feeders as an alternative sub-option on the current East Preston conversion program to provide sufficient feeder capacity to continue with the remaining 6.6 kV to 22 kV conversion works to retire EP. The two new feeders from PTN will be extended into the EP distribution area to convert the remaining 6.6 kV feeders from EP to 22 kV.

Under this option the following residual supply related risks are as follows:

- Introduces substantial supply risk under N-1 condition at PTN due to limited amount of spare transformation capacity.
- EPN zone substations will have two transformers which would not be utilised effectively.
- Operationally the new feeders from PTN extending into the EP area will be highly utilised with limited 22 kV transfer points to adjacent feeders due to the extension from PTN with the two new feeders. This arrangement will limit the ability to restore supply under emergency outage condition on these two feeders (i.e. low supply reliability and security for unplanned outages during peak times).

Table 6-4 shows the planned in-service year and cost estimate for the remaining stages of the East Preston conversion program under this option.

Table 6-4: Option 3 staging and costs

Stages	In Service Year	Cost estimate (Real 2025 $)

EP Stage 7 (two new feeders from PTN)	2028	$38.6M
EP Stage 8	2030	$18.4M

6.4 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)

This option assesses a partial conversion of the remaining EP feeders and transferring of load to the adjacent Fairfield (FF) zone substation.

With FF zone substation being the only remaining 6.6 kV network on the JEN network, this option explores the possibility of transferring 6.9 MVA load from EP onto FF following the completion of EP Stage 7 works. This would then still allow the remaining works for the East Preston conversion program to continue and enable EP zone substation to be retired. However, this option will place additional supply risk on FF zone substation and its 6.6 kV feeders because FF is an islanded 6.6 kV network.

Presently, there is one 6.6 kV FF feeder (FF0-90) which has ties to EP zone substation. Due to the low capacity of the 6.6 kV network, a minimum of three new 6.6 kV feeders would be required from FF zone substation in order to provide sufficient feeder capacity to the transfer 6.9 MVA from EP to FF (approximately 1.6km, 1.8km, 1.7km, of new line for each feeder respectively). Due to the locality of FF zone substation in respect to the East Preston 6.6kV area and the Citipower boundary, in order to facilitate the additional feeders from FF the new routes will cause significant congestion along local streets and will need to cross Darebin Creek.

In addition to the feeder augmentation, it would assume the following planned upstream network augmentation would be completed to provide sufficient capacity to cater for the additional load transferred onto FF.

- Install a new 22/6.6 kV 18 MVA transformer and a new 6.6kV bus at FF zone substation.
- Augment the BTS-FF sub-transmission lines.

Under this option the following residual supply related risks are as follows:

- There still will be costs to replace the end of life distribution assets that have been transferred onto FF.
- EPN zone substations will have two transformers which would not be utilised effectively
- Significant works causing further congestion will be necessary to connect customers and support growth due to 6.6kV distribution voltage, alternatively, long runs of 22kV rated underground cables for neighbouring zone substations will be needed to supply new large customers

Table 6-5 shows the planned in-service year and cost estimate for the EP Stage 7 and with the load transfer to FF under this option.

Table 6-5: Option 4 staging and costs

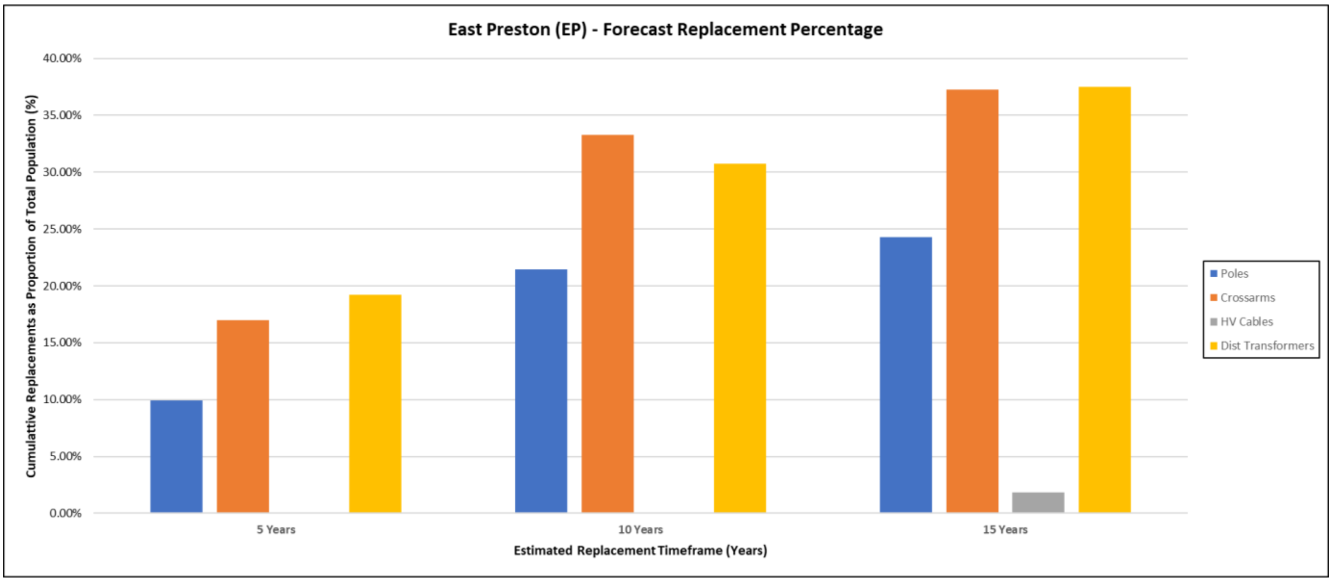
Stages	In Service Year	Cost estimate (Real 2025 $)
EP Stage 7	2028	$30.0M
Install three new FF feeders and load transfer	2030	$14.9M
On-going distribution replacement works and retire EP	2031-35	$16.8M

6.5 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.

The 6.6 kV distribution assets in the Preston area were established over many decades, dating back to as early as the 1920's. Based on the age profiles of the assets, Figure 6-1 shows the cumulative percentages of HV underground cables, distribution substations, poles and cross arms which will require replacement over the next five, ten and fifteen years. Pole replacement is shown to give an indication of asset replacement requirements in the coming fifteen-year period only and not as a comparison to the works required in Option 2. Generally, poles will not need to be replaced if a feeder is converted unless they are found to be unserviceable.

Figure 6-1: EP distribution assets requiring replacement over the next 15 years



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.

Under this option the following residual supply related risks are as follows:

- EPN zone substations will have two transformers which would not be utilised effectively
- Significant works causing further congestion will be necessary to connect new customers and support growth due to 6.6kV distribution voltage, alternatively, long runs of 22kV rated underground cables for neighbouring zone substations will be needed to supply new large customers

Table 6-6 shows the planned in-service year and cost estimate for undertaking like-for-like of the EP 6.6 kV distribution network under this option.

Table 6-6: Option 5 staging and costs

Stages	In Service Year	Cost estimate (Real 2025 $)

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

7. Assessment methodology

This section outlines the key parameters used in the economic assessment and the methodology that JEN has applied in assessing the market benefits associated with each of the credible options considered in this RIT-D. It describes how the classes of market benefits have been quantified and outlines why particular classes of market benefits are considered not material to the outcome of this RIT-D. It also describes the sensitivities applied and the reasonable scenarios considered in comparing the base case 'state of the world' to the credible options.

Our approach aligns with the AER's RIT-D application guidelines, including the principles on reasonable inputs proportionate analysis and treatment of VCR and discount rates.[10]

7.1 Key parameters

7.1.1 Discount rate

We use a regulatory discount rate to express future costs and benefits in present value terms for the central scenario, being 5.24%. For the high scenario we use AEMO's IASR assumption for a commercial discount rate of 7.0%. For the low scenario we use our 2.45% pre-tax real WACC.

7.1.2 Value of customer reliability

Location-specific load-weighted VCR is used to value the EUE representing the deterioration in supply reliability. The locational VCR for the East Preston supply area was derived from the sector VCR estimates provided by the AER, weighted in accordance with the composition of the load, by sector, and escalated by CPI. The base assumption VCR used in this RIT-D is $37,972 per MWh.

Table 7-1: Load weighted VCR calculation

Parameter	Residential	Commercial	Industrial
East Preston supply area load composition	25%	59%	16%
AER VCR (Dec 2025)	$12.36/kWh	$20.25/kWh	$5.36/kWh
Load weighted VCR	$37.97/kWh		
Load weighted VCR (MWh)	$37,972/MWh		

7.1.3 Assessment period

This RIT-D analysis has been undertaken over a twenty-year period, from 2026-27 to 2045-46. We consider that the length of this assessment period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The assessment period accounts for expected demand growth in the East Preston supply area intended to be addressed by the credible options in this RIT-D.

10 AER, Regulatory investment test for distribution, Application Guidelines, November 2024, section 3.

7.1.4 Asset failure rate assumptions

As explained in Section 4.2, the estimated probability of explosive failure of a section of bus, a circuit breaker or a cable termination resulting in a fire and extensive damage to the entire switchboard of 1 in 30 years is based on an actual event that occurred on Jemena's network at Flemington (FT) zone substation over 30 years ago with the same type of switchgear.

Referring both to this historic data, and also to the CBRM model output (which indicates that the bus and circuit breakers are well deteriorated), the following probability assumptions have been applied in the economic assessment.

- Probability of a bus and / or circuit breaker failure affecting multiple buses is 1 in 30 years.
- Repair / replacement time is estimated to be 6 weeks (repair) and 8 months (replacement). For the purpose of the assessment, it is conservatively assumed that repairs could be undertaken within 6 weeks.

There are three 6.6kV buses on EP 'B', therefore the probability of bus unavailability is (1/30) x 3 x (6/52) = 1.15% p.a. To address the AER's expectations on reasonable inputs, we have undertaken additional sensitivity tests on the EP bus failure probability (that is, 1 in 50 to 1 in 20 years). Results showed the preferred option remains unchanged.

7.2 Approach to estimating option costs

The costs for each option have been calculated by our cost estimation team based on recent similar project costs and scope. Costs are expected to be within +/-30% of the actual cost.

The costs presented in this RIT-D are fully loaded including escalations, overheads and management reserve. Ongoing operating and maintenance costs are included in the assessment annually from the year after the capital investment.

Land procurement cost is based on estimated market valuation of potential (or existing held) properties in the supply area, plus costs for establishing services and site access.

Where capital components have asset lives greater than ten years, we have adopted a residual value approach to incorporating capital costs in the assessment, which ensures that the capital costs of long-lived options are appropriately captured in the ten-year assessment period.

All cost estimates are prepared in real 2025 dollars based on the information available at the time of preparing this DPAR.

7.3 Market benefit classes quantified for this RIT-D

This section outlines the classes of market benefits that JEN considers will have a material impact on the outcome of this RIT-D and have therefore quantified.

The class of market benefit quantified for this RIT-D include changes in:

- involuntary load shedding and customer interruption;
- load transfer capacity; and
- Timing of expenditure.

7.3.1 Involuntary load shedding and customer interruptions

Involuntary load shedding is where a customer's load is interrupted (switched off or disconnected) from the network without their agreement or prior warning. Involuntary load shedding can occur unexpectedly due to a network outage event, or pre-emptively to maintain network loading to within asset capabilities. The aim of implementing a credible option for the options considered in this DPAR, is to reduce the amount of involuntary load shedding expected.

A reduction in involuntary load shedding, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed. The avoided involuntary load shedding benefits of a credible option are estimated by multiplying:

- The quantity (in MWh) of involuntary load shedding avoided assuming the credible option is in place; and
- The value of customer reliability (VCR) (in $/MWh).

JEN forecasts and models hourly load for the forward planning period and quantifies the EUE (involuntary load shedding) by comparing forecast load to network capabilities under system normal and network outage conditions.

JEN has adopted the AER's estimate of VCR in quantifying the value of the reduction in EUE.

JEN has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D.

7.3.2 Changes in load transfer capacity

The preferred scheme (Option 2) will remove the last remnants of the 6.6 kV network in the East Preston Area. This will support increased load transfer capacity between the surrounding 22 kV network and the Preston Area. The preferred option is expected to deliver significantly increased load transfer capacity and we have taken this into account in the options assessment.

7.3.3 Timing of expenditure

The costs of credible options assessed in this project include the works required to complete the remaining Conversion Program and, the works required to undertake a like for like replacement of 6.6 kV assets. All costs will be incurred by 2030. Option 1 – Do Nothing, involves stopping the Conversion Program at the end of EP Stage 6 project and is assumed to generate a zero capital cost.

By including the cost of the major works expected under each credible option, JEN has captured potential changes in expenditure timing between the various credible options. These market costs, and any associated benefits, are captured in the economic analysis, and applied to the credible option rankings, outlined in Section 8.

7.4 Market benefit classes not relevant to this RIT-D

This section outlines the classes of market benefits that JEN considers immaterial to this RIT-D assessment, and our reasoning for their omission from this RIT-D assessment. The market benefits that JEN considers will not materially impact the outcome of this RIT-D assessment include changes in:

- embedded generation;
- voluntary load curtailment;
- costs to other parties;
- electrical energy losses;
- option value; and,
- greenhouse gas emissions.

7.4.1 Embedded generation

JEN has assessed the potential for customers to use grid-connected, standby and standalone generation and/or storage solutions in the East Preston supply area as part of our notice of determination report. This assessment showed there was no potential for generation or storage to materially address the need and JEN received no market responses for embedded generation or storage solutions as part of the stage 1 RIT-D consultation process. This market benefit is therefore not relevant to this RIT-D.

7.4.2 Voluntary load curtailment

Voluntary load curtailment is where a customer/s agrees to voluntarily curtail their electricity under certain circumstances, such as high network loading or during a network outage event. The customer will typically receive an agreed payment for making load available for curtailment, and for actually having it curtailed during a network event. A credible demand-side reduction option leads to a change in the amount of voluntary load curtailment.

JEN has assessed the potential for voluntary load curtailment in the East Preston supply area. The notice of determination report concluded that there was potential for voluntary load curtailment to provide sufficient additional capacity to either replace a network solution or to enable a more economic network solution. Nevertheless, JEN received no market responses for demand response solutions as part of the stage 1 RIT-D consultation process. This market benefit is therefore not relevant to the credible options considered in this DPAR.

7.4.3 Cost to other parties

As larger developments come on line in the East Preston area, in the absence of a 22 kV network there will be limited potential to connect, and therefore additional connections would be required to be via 22 kV cables at a significantly higher cost due to the extended feeder length.

As there are currently no applications (expected, or underway), it would not be appropriate to include an estimate of the savings in the cost-benefit analysis. It is also noted that including this potential impact in the options assessment would not change the rankings of the options. Therefore, the market benefits associated with costs to other parties have not been quantified.

7.4.4 Electrical energy losses (Emission reduction)

Reducing network utilisation, through network impedance or supply voltage changes in the East Preston area could result in a change in network losses. Losses are directly paid for by consumers as a part of their electricity bills and as such qualify as a market benefit.

Under Option 5, the losses would remain unchanged, as a like for like replacement would retain the same voltage level and similar values of impedance in the network. Under Option 2, Option 3 and Option 4, losses would be reduced by similar amounts due to the higher operating voltage.

Given the proportionality test, the consideration of electrical energy losses would not change the rankings of the options. Therefore, the market benefits associated with electrical energy losses have not been considered and have therefore been excluded from the market benefit assessments.

Further, we have considered the impacts of emissions reductions in the context of the AER's emission reduction guidance and note that this also does not change the quantum or merit of the options being considered.

7.4.5 Option value

The AER RIT-D application guidelines explain that *"option value refers to a benefit that results from retaining flexibility in a context where certain actions are irreversible (sunk), and new information may arise in the future as a payoff from taking a certain action. We consider that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change".*

In the context of the conversion program, it is noted that the works completed to date are sunk costs delivering material value, and, the identified need for the remaining stages of the program has been identified as safety, maintaining supply reliability and facilitating growth in the Preston area. As previously explained, a credible solution must enable the decommissioning of the major primary assets at EP 'B', including transformers, switchgear and secondary equipment.

It is therefore considered that in this case, there is little value in retaining flexibility, given that the safety need requires decommissioning of the major assets at EP 'B'. JEN has therefore not attempted to estimate any additional option value market benefit for this project assessment.

7.5 Sensitivities

JEN has critically assessed the assumptions and parameters, and determined that the key variables affecting the estimation of net economic benefits in this RIT-D are:

- maximum demand growth rate;
- value of customer reliability (VCR);
- capital costs;
- discount rate; and
- asset failure rate (probability of EP bus failure).

To test the robustness of the cost-benefit analysis to changes in key variables from the base case, the following sensitivities (which vary these assumptions one at a time) have been tested as shown in Table 7–2.

Table 7–2: Sensitivity assumptions

Sensitivity	Lower Bound	Base Case	Higher Bound
Maximum demand forecast	90%	100%	105%
Value of customer reliability	90%	100%	130%
Capital cost	70%	100%	130%
Discount rate	2.45%	5.24%	7.00%
Probability of EP bus failure	1 in 50 years	1 in 30 years	1 in 20 years

7.6 State of the world scenarios

RIT-D assessments are required to be undertaken using cost-benefit analysis that includes an assessment of 'reasonable scenarios', which are designed to take into account the uncertainty associated with different future states of the world when identifying the preferred option. Weighting of the net benefit outcomes across the different scenarios is used to manage the risk associated with the uncertainty of future benefits.

The key assumptions in the analysis that have a relatively high uncertainty in the future are maximum demand and the asset failure rate, which together determine the quantity (MWh) of the EUE.

JEN has therefore adopted three future state-of-the-world scenarios, which each adopt different and consistent assumptions in relation to these two key variables:

- Low VCR, capital cost and failure rate scenario – credible lower bound changes to key assumptions (i.e., VCR, capital cost and EP bus failure rate).
- Central scenario – the central demand forecast and central asset failure rate.

- High VCR, capital cost and failure rate scenario – credible higher bound changes to key assumptions (i.e., VCR, capital cost and EP bus failure rate).

Table 7-3: Scenarios

Scenario	Low Scenario	Central Scenario	High Scenario
Weighting	**25%**	**50%**	**25%**
Value of customer reliability	90%	100%	130%
Capital cost	70%	100%	130%
Probability of EP Bus failure	1 in 50 years	1 in 30 years	1 in 20 years

8. Options analysis

This section presents the base case and summarises the results of the NPV analysis for each option. The net economic benefit analysis has taken account of the EUE risk and expected option costs over the analysis period.

Each credible option has been ranked according to its net economic benefit, being the difference between the market benefit and the costs within the assessment period (present value), compared to outcomes in the base case, and weighted across the three scenarios considered.

8.1 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 overload represented by the value of EUE.

Table 8-1: Do nothing – present value of EUE ($M, 2025)

Option 1	Low Scenario	Central Scenario	High Scenario	Weighted Total
EUE Risk Cost	213	331	584	**365**

8.2 Option 2 – Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN)

The table below sets out the gross market benefits under Option 2 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 2 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 8-2: Option 2 – net present value of net economic benefits ($M, 2025)

Option 2	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	182	287	526	**321**
Total option cost	29	42	55	42
Net Market Benefit	152	245	471	**278**

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

The table below sets out the gross market benefits under Option 3 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 3 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 8-3: Option 3 – net present value of economic benefits ($M, 2025)

Option 3	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	171	273	508	**306**
Total option cost	35	50	65	50
Net Market Benefit	136	223	443	**256**

8.4 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)

The table below sets out the gross market benefits under Option 4 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 4 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 8-4: Option 4 – net present value of economic benefits ($M, 2025)

Option 4	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	177	280	517	**314**
Total option cost	35	50	65	50
Net Market Benefit	143	230	453	**264**

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

The table below sets out the gross market benefits under Option 5 (i.e., the EUE risk cost that is avoided relative to Option 1 (the base case)), the total costs of Option 5 and the net market benefit, all in PV terms, in each scenario and on a weighted basis.

Table 8-5: Option 5 – net present value of economic benefits ($M, 2025)

Option 5	Low Scenario	Central Scenario	High Scenario	Weighted Total
Gross Market Benefit	159	255	484	**288**
Total option cost	49	70	92	70
Net Market Benefit	110	184	392	**218**

8.6 Net economic benefits

The economic analysis shown in Table 8–6, based on the scenario weightings, demonstrates that Option 2 is expected to provide the highest present value of net economic benefits and is therefore the preferred option at this draft stage.

Table 8–6: Cost-benefit analysis (PV, $M, 2025) – weighted across scenarios

Option	Present value of capital and O&M	Present value of gross benefits	Present Value of Net Benefits (NPV)	Ranking
Option 1 – Do nothing (base case)	0	0	0	5
Option 2: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN)	42	321	278	1
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	50	306	256	3

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)	50	314	264	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	70	288	218	4

All network options considered demonstrate substantial, positive net benefits compared with Option 1 (base case), in which no investment is undertaken.

8.7 Sensitivity analysis

Three sets of sensitivities were defined in section 7.5 to test the robustness of the option rankings under the NPV assessment to changes in key assumptions. The focus of the sensitivity testing in on the central scenario, and the sensitivity analysis has tested changes in the assumptions one at a time.

The sensitivity analysis demonstrates that the conclusion that Option 2 is the preferred option is not sensitive to the changes in assumptions tested, as the ranking of the options remains constant, as shown in Table 8-7 and Table 8–8 below.

Table 8-7: Net economic benefits (PV, $M, 2025) – lower bound sensitivity for each assumption (central scenario)

Sensitivity	Option 2	Option 3	Option 4	Option 5	Ranking
Nil	**245**	**223**	**230**	**184**	**Option 2**
Maximum demand forecast	161	145	146	103	Option 2
Value of customer reliability	146	126	131	87	Option 2
Capital costs	270	253	260	227	Option 2
Discount rate	336	310	316	269	Option 2
Probability of EP bus failure	151	129	136	90	Option 2

Table 8–8: Net economic benefits (PV, $M, 2025) – higher bound sensitivity for each assumption (central scenario)

Sensitivity	Option 2	Option 3	Option 4	Option 5	Ranking
Nil	**245**	**223**	**230**	**184**	**Option 2**
Maximum demand forecast	300	268	289	241	Option 2
Value of customer reliability	344	320	330	282	Option 2
Capital costs	220	193	201	142	Option 2
Discount rate	203	183	191	146	Option 2
Probability of EP bus failure	363	341	348	302	Option 2

8.8 Proposed preferred option optimal timing

The optimal timing of the proposed preferred Option 2 occurs when its annualised cost exceeds the combined annual cost of the avoided EUE of Option 1 (do nothing).

The annualised cost of Option 2 is approximately $2.4 million per annum. This is exceeded by the cost of the avoided EUE in 2026 under the weighted scenario as shown in Table 8–9.

Table 8–9: Annualised cost of EUE risk minus annualised investment costs ($M, 2025)

Scenario	2026	2027	2028	2029	2030	2031	Optimal Timing
Weighted	**23.18**	**22.73**	**21.71**	**20.54**	**19.85**	**19.80**	**2026**
Central	12.72	12.69	12.19	11.54	11.24	11.39	2026
Low	20.91	20.54	19.63	18.57	17.96	17.94	2026
High	38.19	37.15	35.40	33.47	32.25	31.91	2026

The optimal completion date for the entire option is by 2026, However given longer construction time needed to convert all 6.6kV distribution assets and customer consultation, the practical timing for completion of Option 2 in full is November 2030.

9. Conclusion and next steps

This section summarises the proposed preferred option identified from the cost-benefit analysis at this draft stage and details next steps in the RIT-D process.

9.1 Proposed preferred option

As summarised in Table 9–1, the proposed preferred option is Option 2 as it is the credible option that maximises the present value of net market benefits. Option 2 satisfies the requirements of the RIT-D.

Table 9–1: Summary of cost benefit analysis (PV, $M, 2025)

Present Value	Option 1	Option 2	Option 3	Option 4	Option 5
Capital costs	0	42	50	50	70
Avoided expected unserved energy (EUE)	0	321	306	314	288
Net Market Benefits (NPV)	**0**	**278**	**256**	**264**	**218**

Consistent with the East Preston Area Network Development Strategy paper, Option 2 is the preferred option and involves:

EP Stage 7: Continue with the feeder conversion works to transfer load from EP 'B' to EPN. This involves establishing 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. The construction work is planned to be completed by 2028. It will involve the conversion of feeders and distribution substations from 6.6 kV to 22 kV.

EP Stage 8: Install a 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, all load on EP 'B' will have been transferred to EPN to allow the decommissioning and removal of all EP 'B' assets. EP zone substation will then be fully decommissioned by 2030.

The proposed preferred option has a total capital cost of $48.4 million (real 2025). The RIT-D assessment has demonstrated that it is expected to provide a net economic benefit of $278 million (PV, 2025), over a twenty-year period.

The analysis has found that the optimal completion date for the entire option is by 2026. However with construction time, to convert all 6.6kV distribution assets and customer consultation, the practical timing for completion of Option 2 in full is November 2030.

9.2 Next steps

JEN invites written submissions on this report from interested stakeholders. All submissions and enquiries should be directed to:

Hung Nguyen
Network Planning Team Leader
Email: PlanningRequest@jemena.com.au

Submissions should be lodged with us on or before 3 April 2026.

All submissions will be published on JEN's website. If you do not wish to have your submission published, please indicate this clearly.

Following consideration of any submissions on this DPAR, JEN will proceed to prepare a Final Project Assessment Report (**FPAR**). That report will include a summary of, and commentary on, any submissions to this DPAR, and present the final preferred option to address the identified need. Publishing the FPAR will the final stage of the RIT-D process.

10. Appendix A – Checklist of compliance clauses

Table 10–1 presents a checklist of the NER (version 220) clause 5.17.4 (j) and references the section within this DPAR where those clauses are addressed.

Table 10–1: Compliance clauses checklist

Clause	Section
(1) a description of the identified need for the investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);	4
(3) if applicable, a summary of, and commentary on, the submissions on the options screening report;	5
(4) a description of each credible option assessed;	6
(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit;	7.3 & 7.2
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	7.4
(5) where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	8
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	6 & 8
(9) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	8.6
(10) the identification of the proposed preferred option;	9.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent; and	9.1
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed	9.2