Jemena Electricity Networks (Vic) Ltd

East Preston Area

Network Development Strategy
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Glossary

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Jemena Electricity Networks Vic Ltd (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 344,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also, million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network alternative	An alternative solution to growing customer demand, which does not involve augmenting physical network assets.
Planning criteria	The methodologies, inputs and assumptions that must be followed when undertaking technical and economic analysis to predict emerging power transfer limitations.
Present Value Ratio (PVR)	PVR index calculates a measure of investment efficiency. It is determined by the present value of benefit divided by the present value of cost.
Probability of exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year:
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, 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 derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	50% POE and 10% POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.
CBRM	Condition Based Risk Management.

Abbreviations

ACS	Class Strategy
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CBRM	Condition Based Risk Management
CMEN	Common Multiple Earthing Neutral
CN	Coburg North Zone Substation
CS	Coburg South Zone Substation
CT	Current Transformer
DDF	Dielectric Dissipation Factor
DP	Degree of Polymerisation
CN	Coburg North Zone Substation
CS	Coburg South Zone Substation
CT	Current Transformer
DDF	Dielectric Dissipation Factor
DP	Degree of Polymerisation
EP	East Preston Zone Substation (existing 66/6.6 kV station)
EPN	East Preston Zone Substation (new 66/22 kV station)
EOL	End of Life
FF	Fairfield Zone Substation
HB	Heidelberg Zone Substation
JEN	Jemena Electricity Network
MD	Maximum Demand
NEM	National Electricity Market
NER	Neutral Earthing Resistor
NH	North Heidelberg Zone Substation
NPV	Net Present Value
NS	North Essendon Zone Substation
OH&S	Operational Health and Safety
OLTC	On Load Tap Changer
P	Preston Zone Substation (retired 66/6.6kV station)
PD	Partial Discharge
PDC	Polarising, Depolarising Current method
POE	Probability of Exceedance
PTN	Preston Zone Substation (new 66/22 kV station)
PV	Pascoe Vale Zone Substation
RVM	Recovery Voltage Method

TTS	Thomastown Terminal Station
VCR	Value of Customer Reliability
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital

Executive Summary

Jemena Electricity Network (Vic) Ltd. (JEN) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Our customers expect us to deliver and maintain a reliable electricity supply at an efficient cost. To do this, we must choose the most prudent solution to address emerging network challenges. This means choosing the solution that maximises the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

This document is an update to the Preston area network development strategy, which presents JEN's electricity supply requirements for the wider Preston area supplying over 24,000 customers, and outlines the identified risks, and how the risks have been quantified. It outlines options to mitigate supply risks economically and identifies the preferred solution to manage the forecast supply risk and reduce safety risks in the area. This strategy was prepared with an economic assessment of the options based on their total lifecycle costs and customer benefits. This approach ensures that JEN can deliver the optimal long-term solution and continue to provide value for money to our customers.

This strategy reflects the following updated information:

- JEN's 2024 load demand forecasts;
- JEN's latest Condition Based Risk Management (CBRM) results;
- Cost estimates for the remaining works / stages for the previously assessed network options;
- Reviewed and updated options analysis;
- Detailed analysis undertaken as part of the East Preston Conversion Stage 6 Regulatory Investment Test for Distribution (RIT-D) process for the screening of non-network options;
- Reviewed and updated economic cost-benefit analysis, based on the above latest information and inputs.

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 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 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 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).

To address the identified needs outlined above, the option which provided the greatest net market benefits over the total lifecycle project cost, and the least cost option to JEN customers in present value terms was 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.

The Preston conversion program was designed to follow a particular sequence, as described in Table ES−1, but the timing and scope of conversion stages have undergone minor changes since the program commenced in 2008.

Table ES−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[1]) 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, retire EP zone substation 6.6 kV assets and convert an isolated portion of FF90 from 6.6 kV 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.

The fifth and last objective of the program has started, with EP Stage 5 completed in June 2022. EP Stage 6 currently in delivery phase with EP 'A' switch house decommissioned in December 2023. This objective has gone through a Regulatory Investment Test – Distribution (RIT-D), completed in 2021. The remaining stages, EP Stage 7 and 8 will also go through a RIT-D process expected to start in 2025.

The aim of this updated Network Development Strategy is to review the identified need and quantify the remaining risks under the fifth objective. This includes a review of the credible options, particularly the timing and scope of the remaining stages of the East Preston conversion works to determine whether our original plans continue to be in customers' best interests or whether an alternative option is now preferred.

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

Options Considered

A total of six options were considered in response to the identified need in the previous version of this Network Development Strategy. Two of these options involved developing non-standard substation designs, which is no longer feasible given the substation work has commenced and is expected to be completed in 2025. Therefore, these two options are not considered in this updated strategy.

The revised options that have been considered and assessed are:

- Option 1: Do Nothing (Base Case);
- 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
- Option 6: Implement non-network solutions.

In addition to the Do Nothing option, Option 2, Option 5 and Option 6 were assessed in the previous revision and have been retained and reviewed in this latest revision. The revised network options, Option 3 and Option 4, are now considered that would vary the scope of the remaining East Preston conversion program (Option 2).

As part of the RIT-D process for EP Stage 6, the Non-Network Options Screening Report was predicated on the need for a non-network option to supply 26.3 MVA[2] (the forecast consumer load supplied from EP zone substation), which would allow all the assets in poor condition to be retired. JEN recognised that a non-network solution supplying 15.5 MVA may be viable if part of the network is also renewed. Smaller non-network solutions would not provide sufficient capacity to be viable options.

This development strategy revisits the potential for non-network options. Our analysis concludes that there are no non-network options that represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. This development strategy therefore confirms JEN's earlier conclusions in relation to the lack of feasible non-network options.

Preferred Option

A summary of the market benefits analysis assessed for each viable option is presented in the Table ES–1-1 below.

Table ES–1-1: Summary of market economic analysis ($ Real 2024)

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
Option 1: Do nothing	$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)	**$40M**	**$232M**	**1**
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	$47M	$209M	3

[2] Based on JEN 2020 Load Demand Forecast at the time of completing Stage 1 of the RIT-D.

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
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)	$47M	$217M	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$67M	$178M	4

This report identifies Option 2 (continue with the current 6.6 kV to 22 kV East Preston Conversion) as the preferred option because it still meets the identified need and maximises the net market benefits compared to all other considered options. Applying the regulated rate of return, the preferred option has a net market benefit of $232 million compared to the 'Do Nothing' option.

It should be noted that the following identified risks have not been quantified or included in the market benefits analysis because they are addressed to the same extent by each of the credible network options:

- Safety risk to personnel due to primary or secondary plant failure; and
- Aged electromechanical relays mal-operation causing loss of supply.

JEN notes that if these benefits were included, the business case for the project would be even more compelling. In addition to these benefits, the reduction in network losses associated with the 6.6 kV to 22 kV East Preston conversion have also not been quantified. In accordance with the proportionality test it was not necessary to quantify its value in the cost-benefit analysis.

To ensure the safety, reliability and security of supply to our customers and to meet the demand for the wider East Preston area to connect customer at an efficient cost, the remaining stage of works for Option 2 is planned to be completed by 2030 as presented in Table ES–1-2 below.

Table ES–1-2: Option 2 Remaining Stages of Works

Stages	In Service Year	Cost estimate[3]	Anticipated works
EP Stage 7	2028	$30.0M	Conversion of EP 6.6 kV feeders and distribution substations to 22 kV, supplied from EPN.
EP Stage 8	2030	$18.4M	Conversion of remaining EP 6.6 kV feeders, distribution substations and section of FF90 6.6 kV feeder to 22 kV, supplied from EPN. Decommission of EP 'B' Zone Substation.

Optimal timing for Preferred Option

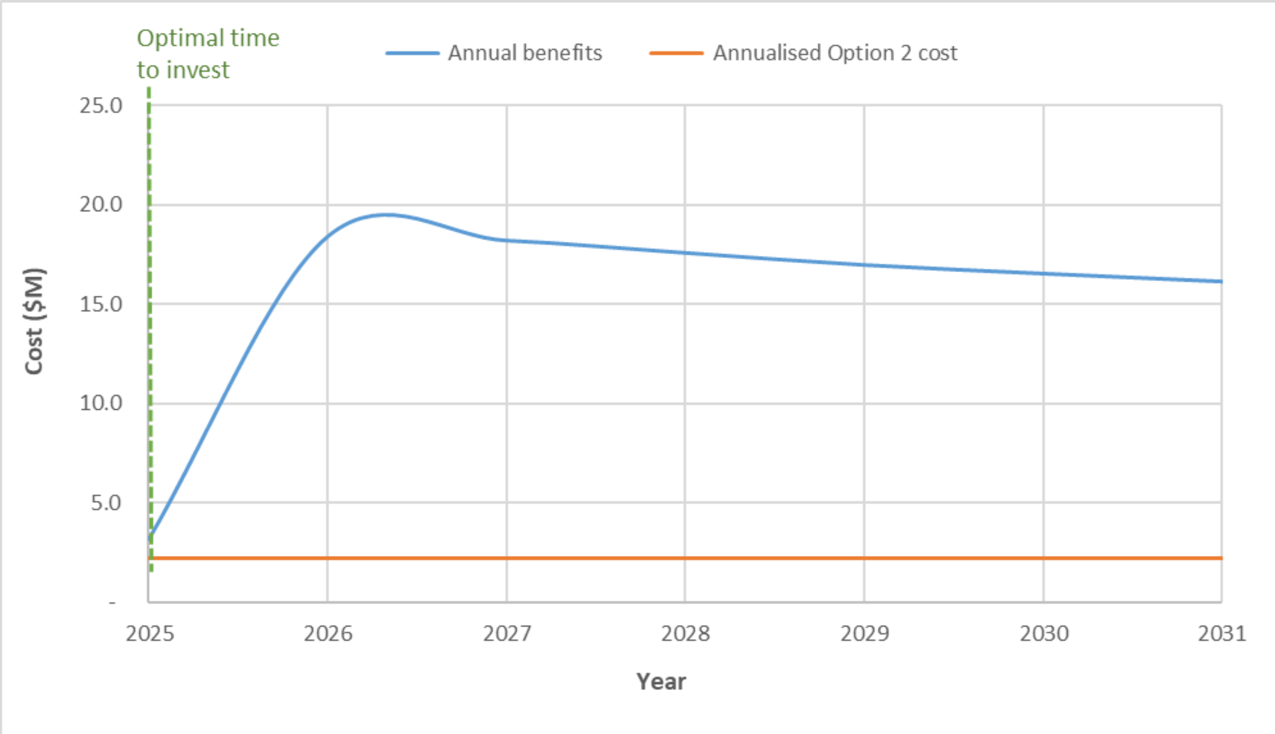
Consistent with JEN's probabilistic planning criteria and economic cost benefit analysis, the optimal timing of a project is when the net cost is minimised when considering both the cost to consumers of expected unserved energy and the cost of augmentation. Therefore, the optimal economic timing of a project is when the expected annualised augmentation benefits, being the reduction in expected unserved energy by undertaking the proposed augmentation works, exceeds the annualised cost of the project.

The net cost of the project is minimised under JEN's current proposed remaining program of works for Option 2. In 2025, the proposed remaining program provides the most optimal mix of maximum expected annual benefits ($3.2M) and the lowest annualised costs ($2.2M) and, therefore, any deferral of the project will erode the annualised net benefit by at a minimum of ($1.0M) to JEN's customers for the first year the project is delayed and increasing to ($13.9M) by 2031. The optimal timing of the project is to complete the remaining East Preston conversion (Option 2) as soon as practically possible.

[3] Real 2024 dollars.

Figure ES−1-1 below further illustrates the economic timing for the preferred option and demonstrates that it is efficient for the preferred option to proceed now as the annualised benefits exceed the annualised cost of investment.

Figure ES−1-1: Economic Project Timing for Option 2



1. Introduction

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 2024 Load Demand Forecast.

1.1 Background

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[4] 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 strategy 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 PTN and EPN respectively on the same sites.

[4] Does not include low voltage services.

The Preston conversion program was designed to follow a particular sequence, as described in Table 1-1, 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 1-1: 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 (EPN5) 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 and convert an isolated portion of FF90 from 6.6 kV 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. EP Stage 6 is in delivery phase with EP 'A' switch house decommissioned in December 2023. This objective has undergone the Regulatory Investment Test – Distribution (RIT-D) process, which was completed in 2021. The remaining stages, EP Stage 7 and 8 will also undergo the RIT-D process and is expected to start in 2025.

Based on the 2024 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 16.7 MVA in 2024 to 19.6 MVA by 2034.
- 10% PoE maximum demand forecast to increase from 17.5 MVA in 2024 to 20.4 MVA in 2034.

1.2 Network supply arrangement

Figure 1-1 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.

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

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

[redacted]

As part of the current EP Stage 6 works, EP 'A' Zone Substation was decommissioned in late 2023 with EP 'B' being the remaining 6.6 kV Zone Substation supplying part of the Preston area. EP has one 66/6.6 kV 27 MVA transformer with two 66/6.6 kV 13.5 MVA, as hot standby transformers supplying ten 6.6 kV feeders. Figure 1-2 illustrates the single line diagram for EP and EPN zone substation as it currently stands.

Figure 1-2: EP/EPN Zone Substation Single Line Diagram (Current)

[redacted]

In 2015, the new 66/22 kV Zone Substation was established as part of EP Conversion Stage 3 (named EPN Zone Substation). EPN is a single 66/22 kV 33 MVA transformer station which has four 22 kV feeders. Following the completion of the past nine conversion stages, the Preston 6.6 kV network area has progressively been converted to 22 kV by extending feeders from CN, CS, North Heidelberg (NH) and EPN. Figure 1-3 shows the EP/EPN single line diagram as it is scheduled to operate in September 2025 with the second 66/22 kV transformer and bus at EPN once EP Stage 6 is completed.

Figure 1-3 EP/EPN Zone Substation Single Line Diagram (After EP Stage 6)

[redacted]

Figure 1-4 Forecast East Preston supply area (April 2024)

[redacted]

The 66 kV sub-transmission network located in this area are:

- Thomastown Terminal Station (TTS) to Watsonia (WT) to North Heidelberg (NH) back to TTS 66 kV loop, comprising:
  - TTS-WT is rated at 1025 A and owned by AusNet Services; and
  - TTS-NH-WT is rated at 1025 A and owned by JEN.
- TTS-PTN-EPN-EP-TTS 66 kV loop is rated at 690 A and owned by JEN; and
- TTS-CS-CN-TTS 66 kV loop is rated at 1025 A and owned by JEN.

1.3 Completed and committed works

Table 1-2 below summarises the current status and staging of works for the Preston conversion program.

Table 1-2: East Preston conversion program status

Staging of works	In Service Year	Status	Anticipated Works
P Stage 1	2008	Completed	Conversion of P feeders and distribution substations
EP Stage 1 & 2	2008	Completed	Conversion of EP feeders and distribution substations
P Stage 2	2009	Completed	Conversion of P feeders and distribution substations
P Stage 3	2012	Completed	Conversion of P feeders and distribution substations
EP Stage 3	2015	Completed	New 66/22 kV single transformer EPN zone substation
P & EP Stage 4	2016	Completed	Conversion of P & EP feeders and distribution substations
P Stage 5	2017	Completed	Conversion of remaining P feeders and distribution substations
P Stage 6	2020	Completed	Decommission P zone substation & establish new 66/22 kV two transformers PTN zone substation
EP Stage 5	2022	Completed	Conversion of EP feeders and distribution substations
EP Stage 6	2025	In Construction	Decommission of EP 'A' zone substation & install 2nd transformer at EPN zone substation
EP Stage 7	2028	Not Started	Conversion of EP feeders and distribution substations
EP Stage 8	2030	Not Started	Conversion of EP feeders and distribution substations. Decommission of EP 'B' zone substation and convert a portion of FF90 from 6.6 kV to 22 kV

2. 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.

2.1 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 and detail 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.

The ability to provide a safe network is limited by the poor condition of major equipment at EP zone substation and non-standard equipment / design, which is at risk of failure and poses serious safety risks which is further provided as an example in the safety risk assessment Table 2-1.

Table 2-1: East Preston zone substation safety risk assessment

Hazard	Hazard Effect	Operational Risk Category	Consequence	Likelihood	Risk Rating
Health and safety risk	Injuries to staff, contractors or	Health, Safety & Environment	Catastrophic (potential exists for explosion/fire during fault. If anyone is in the zone substation	Unlikely (within 1 in 10 years) The likelihood would increase due to	High

Hazard	Hazard Effect	Operational Risk Category	Consequence	Likelihood	Risk Rating
	a member of the public		during fault they could suffer total permanent disability or even death).	increased intensive and frequent diagnostic condition testings, maintenance activities and inspections as a result of the asset condition.	
	Injuries to staff, contractors or a member of the public	Health, Safety & Environment	Catastrophic (potential exists for major injuries to personnel due to excessive step & touch potential).	Rare (>1 per 10 years)	Significant

A ‘Do Nothing’ option would require the aging asset to remain, completely failing to address safety concerns.

2.2 Reliability

JEN’s planning standard for its zone substation assets is based on a probabilistic planning approach which:

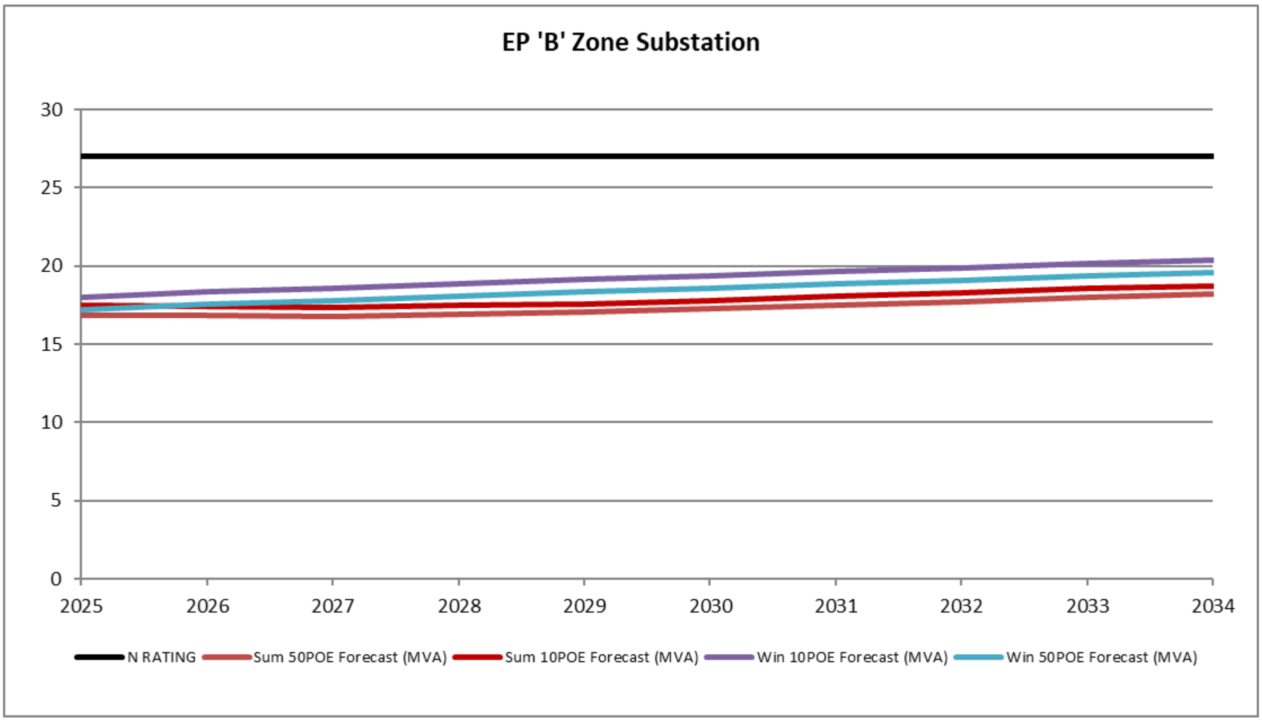
- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options; and
- Estimates expected unserved energy which is defined in terms of megawatt hours (MWh) per annum and 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 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 2–1. The forecasts for the supply area show that the maximum expected demand is 20.4 MVA for EP ‘B’ for the winter 10% PoE in 2034. For EP ‘B’ the forecast demand is relatively flat between 2026 and 2033 following a large step up in demand in the year prior caused by load transfer from EP A as part of EP Stage 6. This forecast includes known spot loads where a customer has made an enquiry or application but does not include potential spot loads that may arise, as these are likely to exceed the capacity of the 6.6 kV system and hence are likely to be supplied from the more remote 22 kV system.

Figure 2–1: EP 'B' zone substation load forecast



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

With EP 6.6. kV distribution feeders, there is limited capacity for load transfers on feeders EP33, EP34, and EP36 in the event of an outage. Typically, due to the radial network of a distribution feeder, a feeder should not be loaded well above 85% utilisation under system normal conditions to allow sufficient emergency transfer under outage conditions. In addition to the shortfall of transfer capacity, one of these feeders is forecast to exceed its thermal line carrying capacity during system normal conditions. Table 2-2 present the 10% PoE forecast utilisation for three of EP heavily loaded feeders. The limitations on the EP 'B' 6.6 kV feeders are associated with the inability to restore feeder supply under N-1 only due to a lack of spare capacity.

Table 2-2: Feeder Forecast Utilisation

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

2.3 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 is under construction with the goal to replace all existing busses with electric busses. Over the next 10 years it is forecast 56 EV Busses will be in operation.
- Darebin City Council has a strategy and plan to facilitate urban growth in the Oakover Village Precinct around the Preston area to a mixed use consisting of high-rise residential, commercial and retail developments. The forecast total maximum demand over the next 10 years is 12 MVA.

Other significant developments in the East Preston area include:

- Several large organisation have begun the redevelopment of Preston Market as part of a new residential and retail complex. It is expected the development will expand and connect to the Preston railway station. This redevelopment will include residential, retail, traditional market and modern shopping facilities.
- Northland shopping centre is beginning to develop a new residential precinct which is outlined to include a new high rise building with commercial and residential facilities. It is forecast this will provide 20,000 residents with housing.

With the available infrastructure, the new loads will be difficult and costly to supply at the 6.6 kV voltage level; more so than the recommended solution. At 6.6 kV, additional new feeders will be difficult to establish, and if physically possible, will be at a significantly higher cost due to congestion in the surrounding areas as well as other assets in the ground for which adequate clearances must be maintained.

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. We consider this further in section 5.1.2.3.

3. Assessment methodology and assumptions

This section outlines the methodology that JEN applies in assessing its network supply risks and limitations. It presents key assumptions and input information applied to the assessments described in this development plan.

3.1 Probabilistic economic planning

JEN applies a probabilistic planning method that considers the likelihood and severity of critical network conditions and outages and their duration. The method compares the forecast cost to consumers of a loss of energy supply due to a network limitation, against the proposed augmentation cost to mitigate the energy supply risk.

The annual cost to consumers is calculated by multiplying the expected unserved energy (EUE) (the expected energy not supplied based on the probability and duration of the supply capacity limitation occurring in a year - a proxy for supply reliability) by the Value of Customer Reliability (VCR).

The present value of this expected benefit is then compared with the costs of the feasible solutions and options. In essence, the total lifecycle cost for each credible solution and option includes the project capital cost, the annual on-going operating and maintenance expenditure (O&M), and the annual cost of the EUE.

3.2 Assessment assumptions

The key assumptions that have been applied in quantifying the East Preston Supply Area limitations are outlined in this section, and include:

- Network asset condition;
- Network outage rates;
- Value of customer reliability (VCR);
- Discount rates; and
- Project costs.

3.2.1 Network asset condition

3.2.1.1 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 below Figure 3-1. A health index exceeding 7 represents serious deterioration with a high risk of failure.

Figure 3-1: 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[6]. 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 3-1.

Table 3-1: 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

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

demonstrated that the DDF values on section of the EP switchgear of up to and exceeding 5%, which means the switchgear is severely degraded.

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.

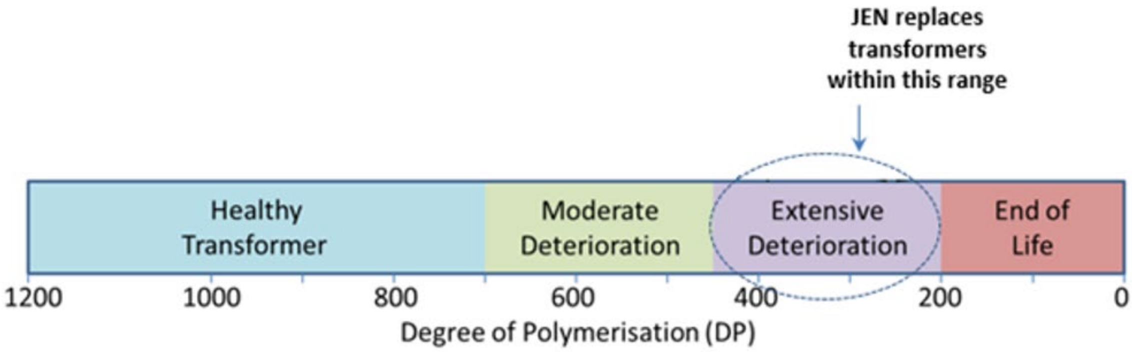
Transformers

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 3-2 below.

Figure 3-2: 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 3-1 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 after EP zone substation is retired, this transformer will be retained as a spare emergency transformer on the JEN network.

Table 3-1: CBRM Result Summary EP (transformer)

Equipment	Age (years)	Health Index forecast (derived from CBRM)	
		2024	2028

EP transformer No.2	16	1.6	2.0
EP transformer No.3	63	7.6	8.5
EP transformer No.4	64	7.3	8.1

3.2.1.2 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).

3.2.2 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.

3.2.2.1 EP transformer and switchgear failure rates

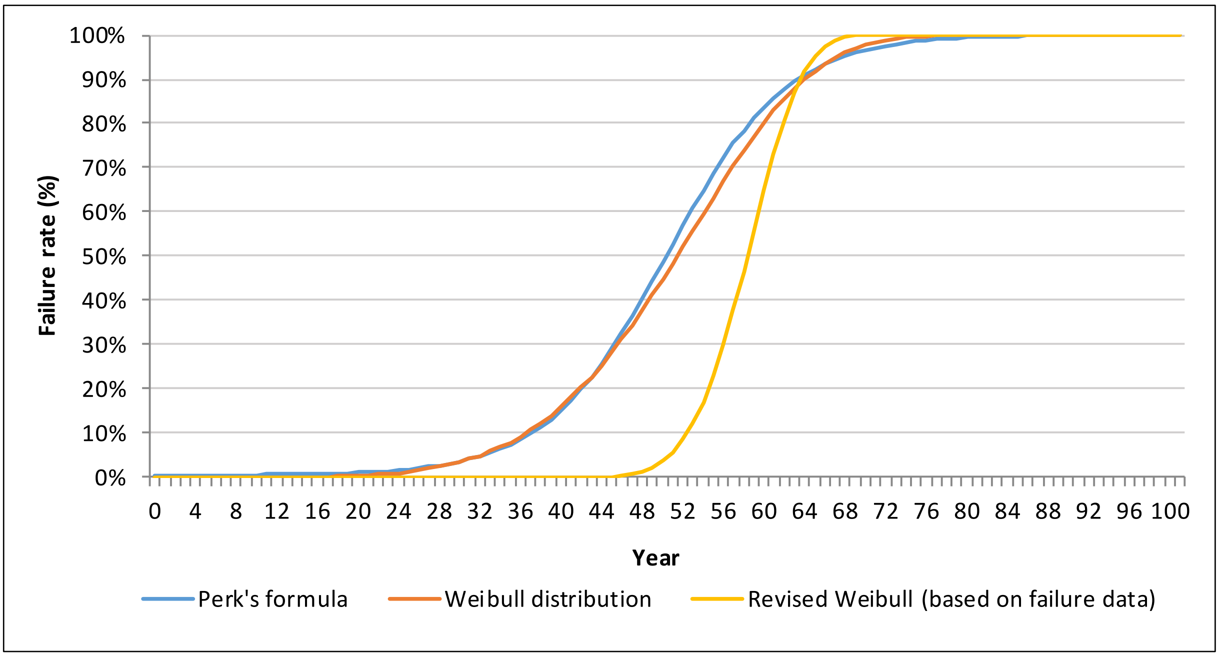
The probability of failure of the EP transformers and switchgear is based on predictions of remaining life taken from our CBRM assessments. Distribution curves were fitted to the data to establish a probability of failure curve. This was then compared to Perk's formulae as a sense check[7].

When considering the switchgear at EP, it was possible to correlate a good fit with a Weibull 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 3-3 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.

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

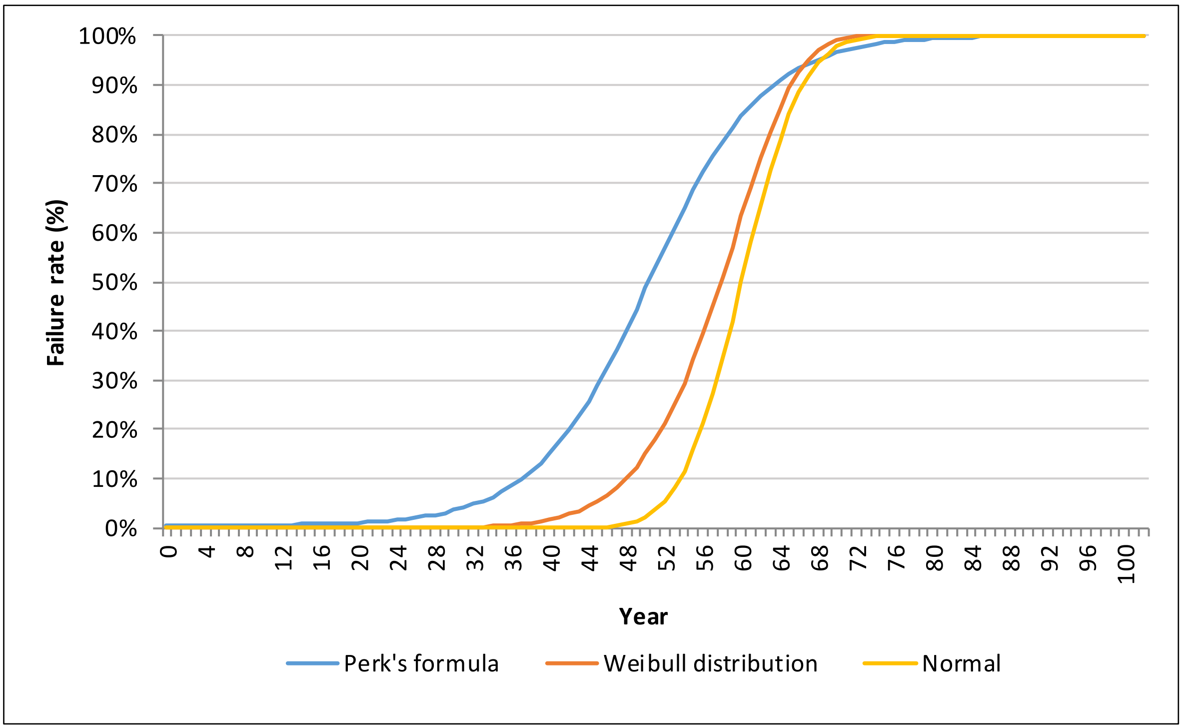
Figure 3-3: EP switchgear failure curve



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 3-4 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 3-4: EP transformer failure curve



3.2.2.2 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 provided in Appendix A: Catastrophic failure at FT zone substation, 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.

To further validate the robustness of the failure probability on the impact of the expected unserved energy at risk and option analysis, including optimal timing for the project, a 1 in 50 years probability of bus failure is applied as a sensitivity analysis to determine whether the optimal timing of the project would change with a very low probability that is not supported by the condition of the equipment. This sensitivity analysis is demonstrated in section 6.3.

3.2.3 Value of customer reliability

The cost of unserved energy is calculated using the value of customer reliability (VCR). This is an estimate of how much value electricity consumers place on a reliable electricity supply.

JEN has calculated a VCR of $47,905/MWh (in 2024 Australian dollars) to be applied to all limitation assessments. This VCR was developed using the AER's value of customer reliability review and applying JEN's customer energy consumption composition, comprising an approximate 34% residential, 41% commercial and 25% industrial split.

3.2.4 Discount rates

A regulatory discount rate has been applied in undertaking the Net Present Value (NPV) assessment of options.

3.2.5 Project costs

The network project capital costs have been forecast by JEN's internal Front-End Engineering Design team. Consideration has been given to recent similar and past projects and expected costs based on site-pro specific construction complexities and industry experience. These project estimates have been prepared for planning purposes and are therefore subject to an estimate range of ±30%, which has therefore been applied to the sensitivity studies for this network development strategy. A detailed functional scope was prepared for the preferred option in order to produce the project cost estimates. Project costs are in Real 2024 dollars. Refer to Appendix B: Project Cost Estimates for further detail of cost breakdown of the cost estimates for the preferred option.

4. Summary of potential options

This section outlines the credible options considered in this report, and outlines the proposed works associated with each credible option.

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 4-1. EP Stage 6 is committed and currently in progress for a scheduled in-service date of September 2025.

Table 4-1: 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

Table 4-2: East Preston conversion program – remaining works

Staging of works	In Service Year	Status	Anticipated Works
EP Stage 6	2025	In Construction	Decommission of EP 'A' zone substation and install 2nd transformer at EPN zone substation
EP Stage 7	2028	Not Started	Conversion of EP feeders and distribution substations
EP Stage 8	2030	Not Started	Conversion of EP feeders, distribution substations and an isolated section of FF90 feeder. Decommission of EP 'B' Zone Substation

Prior to committing to the remaining stages of the East Preston conversion program (as described in Table 4-2), this development strategy considers the following options:

- 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
- Option 6: Non-network solutions.

In addition to Option 1, the 'Do Nothing' option, Option 2, Option 5 and Option 6 were assessed in the previous version of this paper 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 (Option 2) based on the latest load demand forecast.

4.1 Option 1 – Do Nothing (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 $47,905/MWh (2024 $), as described in Section 3.2.3.

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 a zero cost.

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

This option is consistent with the overall strategy for the wider Preston area and continues the conversion of the East Preston area in stages from 6.6 kV to 22 kV.

As described above (see Table 4-1), nine out of a total of twelve stages of the Preston conversion program have been completed to date. EP Stage 6 is currently in the delivery phase and is expected to be completed by the end of September 2025. In summary, the works for EP Stage 6 involves the following:

- Transfer feeders EP7, EP9, EP16 and EP18 from EP 'A' to EP 'B' using out of service feeder circuit breakers EP28, EP32 and EP33.
- Decommission and demolish EP 'A' switchroom and the EP No.1 66/6.6 kV 20/22.5 MVA transformer.
- Install a second 66/22 kV 20/33 MVA transformer and second 22 kV bus at EPN with one new 22 kV feeder.

This stage will eventually allow for EP to be decommissioned by 2030. The remaining two stages (EP Stage 7 and 8) are to be completed by within the 2026-2031 period.

The high-level scope of works for the remaining two stages are further described below.

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 4-3 shows the planned in-service year and cost estimate for the remaining stages of the East Preston conversion program under this option. Refer to Appendix B: Project Cost Estimates for further detail of cost breakdown of the cost estimates for this option.

Table 4-3: Option 2 staging and costs

Stages	In Service Year	Cost estimate (Real 2024 $)
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.

4.3 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 East 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 will be:

- 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 4-5Table 4-4 shows the planned in-service year and cost estimate for the remaining stages of the East Preston conversion program under this option.

Table 4-4: Option 3 staging and costs

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

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

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, there will still costs to replace the end of life distribution assets that have been transferred onto FF.

Table 4-5 shows the planned in-service year and cost estimate for the EP Stage 7 and with the load transfer FF under this option.

Table 4-5: Option 4 staging and costs

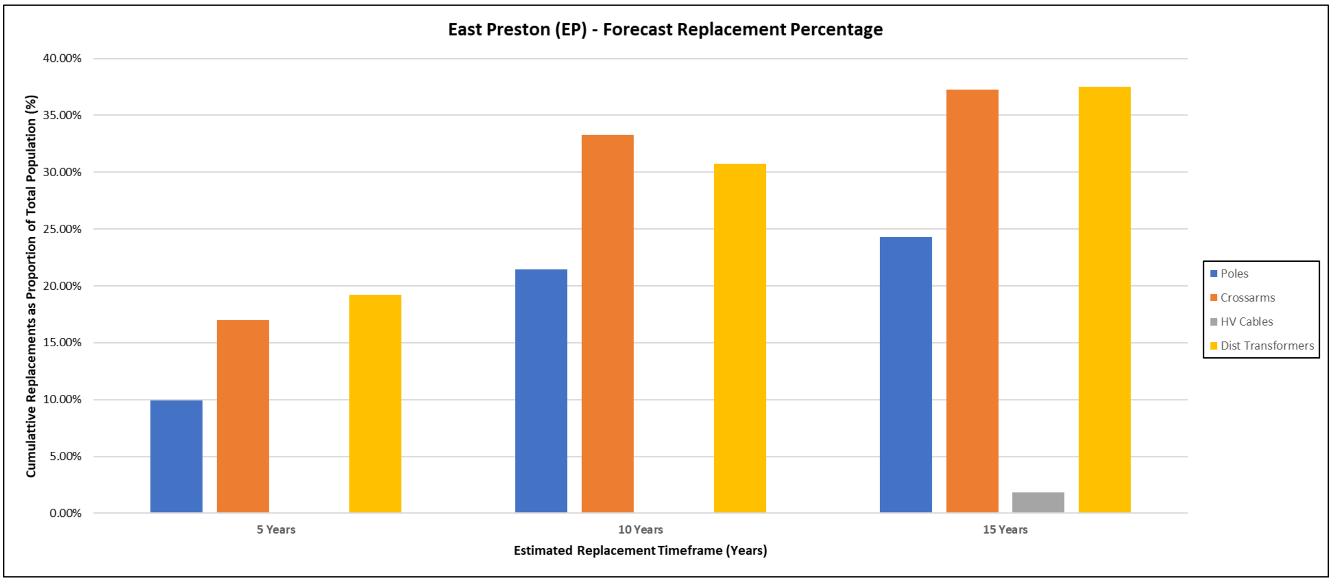
Stages	In Service Year	Cost estimate (Real 2024 $)
EP Stage 7	2028	$30.0M
Install three new FF feeders and load transfer	2030	$14.9M
On-going distribution replacement works and retire EP	2031-35	$16.8M

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

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

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 4-1 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 4-1: 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.

Table 4-6 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 4-6: Option 5 staging and costs

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

4.6 Option 6 – Non-network solutions

Potential non-network options that could meet the project objectives (as envisaged in the AER RIT-D Application Guidelines[8] Section 6.1) were considered based on two alternatives, Generation or storage, and Demand Management.

[8] AER - RIT-D application guidelines - August 2022

Generation

Generators in the assessment include the following types:

- Gas turbine power stations – stand-alone generation built for the purpose of replacing the aged network assets;
- Co-generation from industrial processes; and
- Generation using renewable energy – typically using gas collected from land-fill or a wind turbine embedded in the sub transmission or distribution network.
- Co-generation solutions owned by a customer could have cost benefits to that customer and hence be more economic than a generator for the sole purpose of network support.

A disadvantage of non-inverter-based embedded or co-generation is that it can significantly increase the fault current levels on the network, particularly on the 6.6 kV network where the existing fault levels are already close to the fault current rating of the substation and regulatory limits (e.g. Electricity Distribution Code of Practice). This limits the maximum amount of embedded generation that can be connected.

Storage

Storage could be by a large battery installation or by a large customer energy storage scheme. The assessment did not differentiate the type of storage solution.

Demand side management

Demand side management, such as voluntary load reduction or small battery storage, can alleviate supply risks caused by network inadequacies by reducing and/or shifting the peak demand. The resulting reduction in peak demand can potentially defer the need for major network augmentation or help to better manage the risk until a major network augmentation can be commissioned or is economically feasible. In the case of the East Preston supply area, the need is to remove aged assets from service rather than to delay the works and, therefore, demand side management was assessed only as a replacement for the network assets.

Customer profile

Potential embedded generation, energy storage or demand reduction solutions are limited by the demand of a customer, i.e. an individual customer can only reduce its demand to zero. Typically, the absence of large customers limits the potential for large demand side solutions. The breakdown of customers in the East Preston supply area is shown below in Table 4-7.

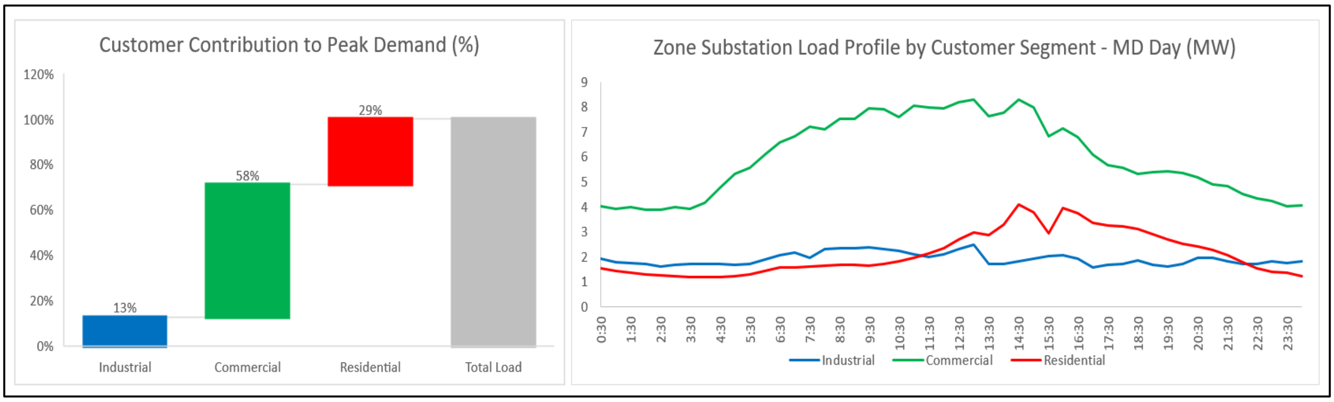
Table 4-7: East Preston customers by category (2024)

Customer Type	EP ‘B’	EPN	Total
Residential	3,632	6,437	10,070
Commercial	325	1,009	1,334
Industrial	16	113	129
Total	3,974	7,559	11,533

Figure 4-2 below shows the customer contribution to peak demand at EP ‘B’ zone substations servicing the East Preston supply area. Commercial and Industrial customers account for approximately:

- 14 MW load during peak demand at EP ‘B.

Figure 4-2: EP ‘B’ Customer Contribution to Peak



4.6.1 Credible scenarios

The National Electricity Rules requires proponents to investigate whether a non-network option (or combination of non-network measures) can avoid the need for investment in a network solution or at least allows a smaller network investment to meet the identified need.

Potential non-network scenarios are:

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

Scenario 1

Meeting the identified need in its entirety through a non-network solution would require measures capable of meeting maximum forecast load requirements (20 MVA) with a level of redundancy to cover this need when the largest single source of power fails.

Scenario 2
The most realistic scenarios for non-network options making a potentially credible contribution to the project’s objectives are where they allow for a reduced level of investment below the preferred network solution.

Consistent with the National Electricity Objective to maintain a safe and reliable supply to customers, a network solution ultimately requires additional transformation capacity at EPN zone substation. The timing of the second transformer (2025) is currently set to allow the conversion of the EP ‘B’ feeders to 22 kV (2028) and the subsequent decommissioning of the EP ‘B’ zone substation. The installation of the second transformer could have been avoided by a non-network solution that matched the difference between the current transfer capacity of the system when operating under a N-1 condition and the forecast load. This scenario was assessed in the RIT-D EP for Stage 6 which JEN did not receive any submission from the market. Hence JEN is now committed to delivery of the second transformer at EPN.

4.6.2 Assessment approach and findings

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

- **Addresses the identified need:** by delivering energy to reduce or eliminate the need for the investment
- **Technically feasible:** there are no constraints or barriers that mean an option cannot be delivered in the context of this investment
- **Commercially feasible:** non-network options make commercial sense in terms of potentially delivering a better economic result than the preferred investment

- **Timely** and can be delivered in a timescale that is consistent with the identified need.

Figure 4-3 shows the rating scale we have applied to assess non-network options.

Figure 4-3: Assessment Rating Criteria

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

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

Figure 4-4 shows the assessment of non-network options against the RIT-D criteria. The assessment shows that a credible non-network option was not identified when considered both in isolation, and in combination with network solutions.

Figure 4-4: Assessment of non-network options against RIT-D criteria

Options	Assessment against criteria			
	Meets Need	Technical	Commercial	Timing
1.0 Generation and Storage				
1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
2.0 Demand management options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

5. Market Benefit Assessment Methodology

This section outlines the methodology that JEN has applied to assess the market benefits associated with each of the credible options considered in this report. It describes how the classes of market benefits have been quantified and outlines why some classes of market benefits have not been quantified in the cost-benefit analysis. It also describes the reasonable scenarios considered in comparing the base case 'state of the world' to the credible options considered.

The economic analysis has been assessed over a twenty-year period. The market benefits assessment was based on JEN's 2024 load demand forecasts.

5.1 Market benefits classes

5.1.1 Market Benefits Classes Quantified

This section outlines the following classes of market benefits that JEN considers will have a material impact on this project and have therefore been quantified:

- Involuntary load shedding and customer interruptions;
- Load transfer capacity; and
- Timing of the expenditure.

Each are addressed in turn below.

5.1.1.1 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 even, or pre-emptively to maintain network loading to within asset capabilities. The aim of a credible option, such as demand side management or a network capacity augmentation, is to provide a change in 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 involuntary load shedding of a credible option is derived by:

- The quantity (in MWh) of involuntary load shedding required, assuming the credible option is completed, multiplied by
- The value of customer reliability (in $/ MWh), which JEN has calculated to be $47,905/MWh based on the AER's value of customer reliability review and applying JEN's customer energy consumption composition, comprising an approximate 34% residential, 41% commercial and 25% industrial split.

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

5.1.1.1 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. Therefore the preferred option is expected to deliver significantly increased load transfer capacity and have been included in the risk assessment.

5.1.1.2 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 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 6.

5.1.2 Market benefits classes not included

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

- Voluntary load curtailment;
- The capacity of embedded generators to take up load;
- Costs to other parties;
- Option value; and
- Electrical energy losses.

5.1.2.1 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.

An increase in voluntary load curtailment, compared to the Base Case, results in a negative contribution (a cost) to the market benefits of the credible option.

JEN has assessed the potential for voluntary load curtailment in the East Preston supply area. This assessment showed there was minimal potential for voluntary load curtailment to provide sufficient additional capacity. In addition, Options 2, 3, 4 and 5 would provide net benefits in terms of the reduced need for a voluntary load curtailment. Therefore, this market benefit was not quantified as it was considered to be not material.

5.1.2.2 Embedded Generators

JEN currently has no significant embedded generators (>1 MW) connected to the Preston zone that would be affected by any of the credible options.

5.1.2.3 Costs 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.

5.1.2.4 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.

5.1.2.5 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[9] and note that this also does not change the quantum or merit of the options being considered.

[9] AER, *Valuing Emissions Reduction, AER Guidance and explanatory statement*, May 2024.

6. Options analysis

This section presents the base case and summarises the analysis results of potential options. The annualised cost for the Base Case (Do Nothing) and each of the options is presented, as is the net economic benefit calculated for each potential option. The net economic benefit analysis has been assessed considering the network risk and expected augmentation costs for the twenty-year period from 2025 to 2045. The emergency load transfer capacity from EP 'B' switch house is included in the expected unserved energy calculations presented in this report. Although there is one 6.6 kV feeder tie between EP and FF, the FF feeder does not have sufficient capacity to allow for load transfers without overloading the feeder.

Each potential augmentation option has been ranked according to its net economic benefit, being the difference between the market benefit and its total lifecycle cost over the assessment period.

6.1 Network limitations

6.1.1 Base case (do nothing)

The base case considers the impact of a 'Do Nothing' scenario, which would include no additional investment in the East Preston distribution network (beyond the previously committed investment). The East Preston Conversion Program is currently committed up until the end of EP Stage 6 which is scheduled to be completed by late 2025. Following the completion of this stage, under the base case (Do Nothing), the remaining 6.6 kV network from EP will be retained, and essentially running the 6.6 kV assets to failure.

Involuntary load shedding would be expected following the failure of the EP 6.6 kV assets. The impact of the asset failure and network limitations under the base case is presented in Table 6-1. It should be noted that the following identified risks have not been quantified or included in the market benefits analysis; if they were then the business case would be even more compelling as the benefits are expected to be significant:

- Safety risk to personnel due to primary or secondary plant failure; and
- Aged electromechanical relays mal-operation causing loss of supply.

Table 6-1: Cost of expected unserved energy at risk under base case

Year	Total cost of expected unserved energy at risk ($M 2024)
2025	21.3
2026	21.3
2027	21.6
2028	21.9
2029	22.4
2030	23.0
2031	23.7
2032	24.4
2033	25.0
2034	25.6
2035	26.3
2036	27.0
2037	27.8
2038	28.6
2039	29.5
2040	30.4
2041	31.5
2042	32.6
2043	33.8
2044	29.2

6.2 Economic market benefits

The net economic benefits are the market benefits, less the cost (negative benefit) to implement the credible option being considered. Table 6-2 shows the cost, net economic benefit, and the project ranking of each option relative to the Do Nothing option. All feasible network options commence in 2025, once the EP Stage 6 is expected to be operational.

The feasible options have been ranked based on their present value of net economic benefit, which is the total benefits provided over a 20 year period, minus the remaining total lifecycle project cost to implement the credible option being considered. Consistent with JEN's original Preston area network development strategy, using the total remaining lifecycle project cost to calculate the net market benefits[10] allows us to maintain sight of the optimal long-term network development plan, rather than just considering the short-term costs and benefits. This approach ensures that JEN can deliver a critical long-term network project at least cost and continue to provide value for money to our customers.

The assessment results show that the feasible option that maximises the net economic benefits is Option 2. This option includes decommissioning EP zone substation by 2030. This option is JEN's proposed preferred option because it meets the identified need and maximises the net economic benefits compared to all other credible options.

Table 6-2: Net Economic Benefit of each option

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
Option 1: Do nothing	$0	0	5

[10] Net market benefits are the actual benefits having considered the cost to implement the proposed project.

Option 2: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from East Preston (EPN)	**$40M**	**$232M**	**1**
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	$47M	$209M	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)	$47M	$217M	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$67M	$178M	4

6.3 Sensitivity analysis

Sensitivity analysis has been undertaken on key variables likely to have the largest impact on the net economic benefit and relative ranking of the options. The variables that have been assessed are:

- Value of customer reliability (VCR);
- Project costs; and
- Network outage rates (probability of EP bus failure).

The sensitivity of the appraisal to changes in the first two variables was assessed for the following two scenarios:

1. Higher than expected costs (+30%), lower than expected VCR (-10%); and
2. Lower than expected costs (-30%), higher than expected VCR (+10%).

The sensitivity analysis demonstrated that the conclusion were not sensitive to the changes, as the ranking of the options remained constant as shown by the results in Table 6-3 and Table 6-4 below.

Table 6-3: Scenario 1 - Net Economic Benefit of each option (high cost & low VCR test)

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
Option 1: Do nothing	$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)	$52M	$177M	1
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	$62M	$150M	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)	$62M	$158M	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$87M	$106M	4

Table 6-4: Scenario 2 - Net Economic Benefit of each option (low cost & high VCR test)

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
Option 1: Do nothing	$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)	$28M	$287M	1
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	$33M	$268M	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)	$33M	$277M	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$47M	$249M	4

Table 6-5 presents the result of the economic analysis for each option if the 1 in 30 year probability of a bus failure is changed to a 1 in 50 year event (an extremely low probability). Based on the results, the preferred option or the optimal timing of the project does not change. The results show Option 2, is the option that maximises the net market benefit, and therefore is still the preferred option.

Table 6-5: Net Economic Benefit of each option (using 1 in 50 year probability of bus failure)

Option	Total PV Cost (Real 2024 $)	NPV of net market benefits	Ranking
Option 1: Do nothing	$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)	$40M	$123M	1
Option 3: Continue with the final two stages of the 6.6 kV to 22 kV East Preston conversion from Preston (PTN)	$47M	$100M	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)	$47M	$108M	2
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$67M	$68M	4

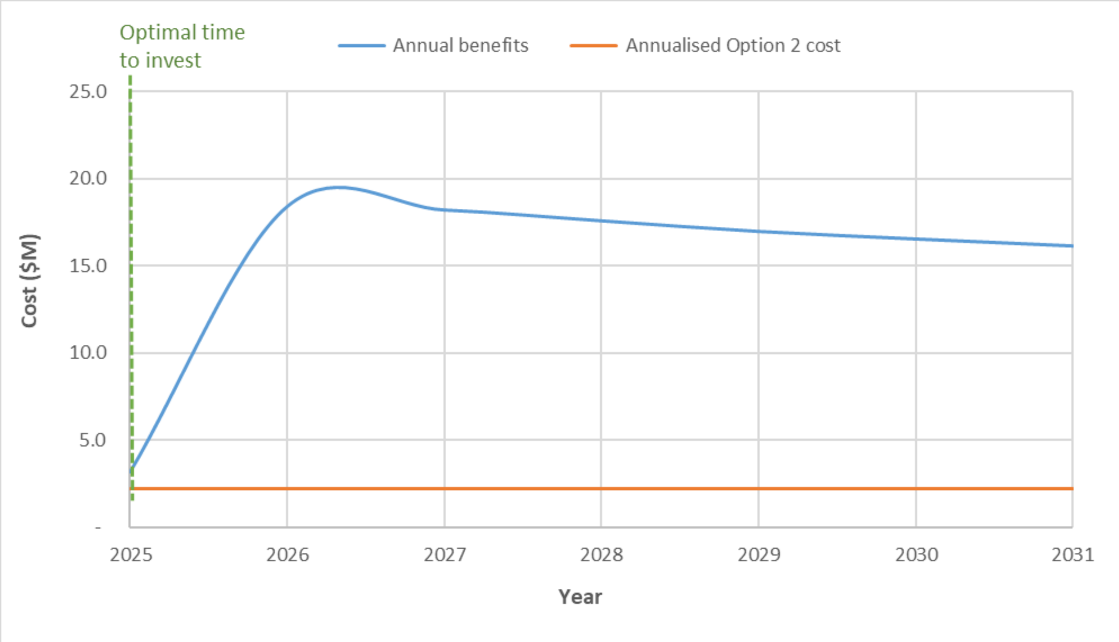
6.4 Preferred option optimal timing

Consistent with JEN's probabilistic planning criteria and economic cost benefit analysis, the optimal timing of a project is when the net cost is minimised when considering both the cost to consumers of expected unserved energy and the cost of augmentation. Therefore, the optimal economic timing of a project is when the expected annualised augmentation benefits, being the reduction in expected unserved energy by undertaking the proposed augmentation works, exceeds the annualised cost of the project. The annualised capital cost of augmentation is calculated using the project costs, a project life of fifty years, and a regulatory discount rate.

The net cost of the project is minimised under JEN’s current proposed remaining program of works for Option 2. In 2025, the proposed remaining program provides the most optimal mix of maximum expected annual benefits ($3.2M) and the lowest annualised costs ($2.2M) and, therefore, any deferral of the project will erode the annualised net benefit by at a minimum of ($1.0M) to JEN’s customers for the first year the project is delayed and increasing to ($13.9M) by 2031. Therefore, the optimal timing is to complete the remaining East Preston conversion (Option 2) as soon as practically possible. Based on JEN’s experience, given the project planning, consultations and the amount of load conversions that would still need to occur, it is not likely to deliver the final two stages of the East Preston conversion program and retire EP earlier than 2030.

Figure 6-1 further illustrates the economic timing for the preferred option and demonstrates that the preferred option should proceed as soon as practicable as the annualised benefits exceeds the annualised cost of investment.

Figure 6-1: Economic project timing for preferred option



7. Conclusion and next steps

The assessment outlined within this report shows that the identified need associated with the East Preston supply comprises:

- the concerns around the safety of the poor condition assets at East Preston zone substation;
- the level of reliability provided by the poor condition assets; and
- the potential limitations for new customer connections caused by the capacity limitations of the 6.6 kV network.

7.1 Preferred solution

The assessment shows that the preferred solution is to complete the final two stages of the East Preston conversion as per the proposed project timing. Costs and anticipated works are presented in Table 7-1. Further detailed cost breakdown for the preferred solution is provided in Appendix B: Project Cost Estimates.

Table 7-1: Option 2 East Preston conversion – remaining stages

Stages	In Service Year	Cost estimate[11]	Anticipated works
EP Stage 7	2028	$30.0M	Conversion of EP 6.6 kV feeders and distribution substations to 22 kV, supplied by EPN.
EP Stage 8	2030	$18.4M	Conversion of remaining EP 6.6 kV feeders and distribution substations. Decommission of EP 'B' Zone Substation and convert a portion of FF90 from 6.6 kV to 22 kV, supplied by EPN.

Applying the regulatory discount rate, the preferred solution has a net market benefits of $232 million compared to the 'Do Nothing' option.

7.2 Next steps

In accordance with Clause 5.17 of the National Electricity Rules and as per the process defined in the AER's RIT-D Application Guidelines, for projects that are subject to the RIT-D, JEN undertakes RIT-Ds to identify 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.

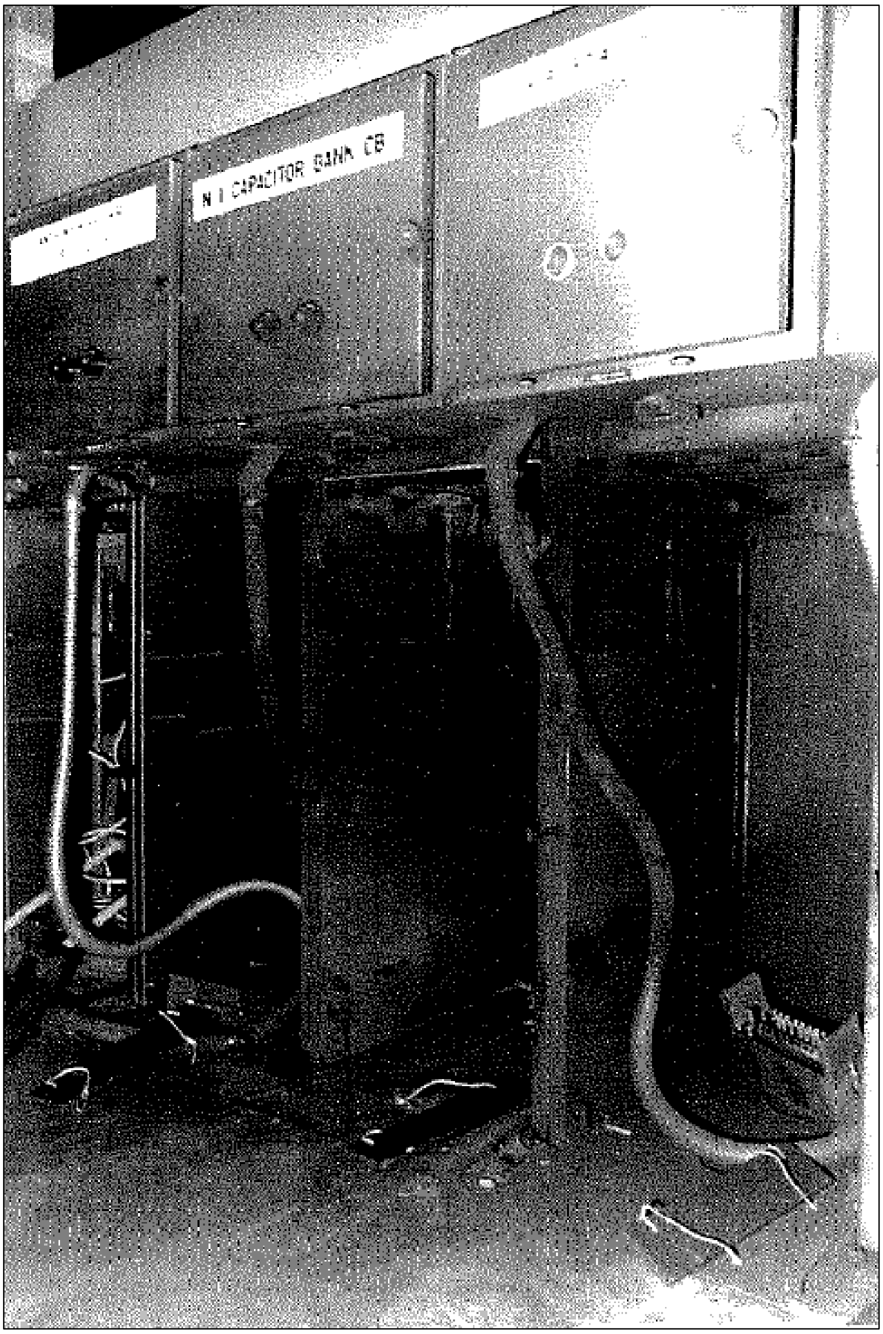
As outlined earlier within this report, EP Stage 6 has completed the RIT-D process in 2021. EP Stage 6 is currently in the delivery phase and is expected by be completed in 2025.

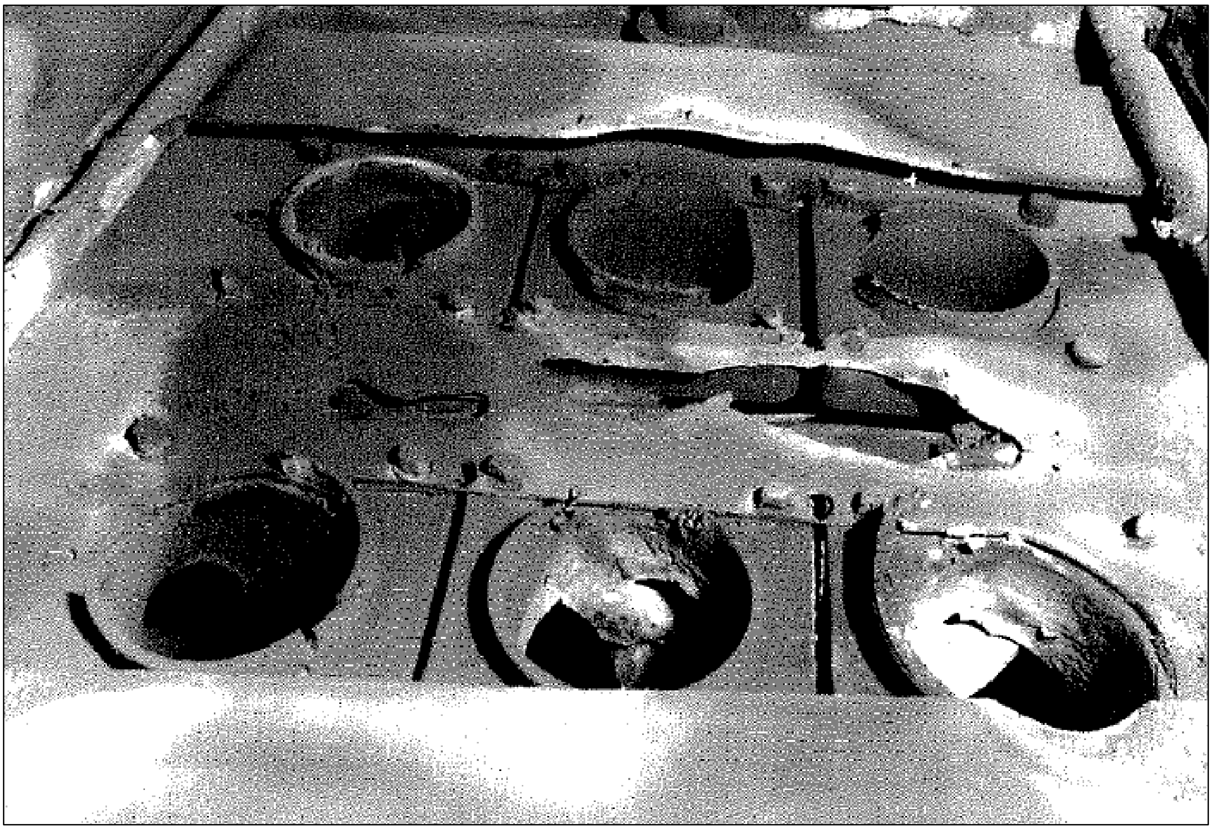
Similar to EP Stage 6, JEN intend to commence the RIT-D process for the remaining two stages (EP Stage 7 and EP Stage 8) in 2025. JEN will continue to work through the RIT-D process to consult with industry and confirm the proposed preferred option and scope for each of the remaining stages of the East Preston conversion, to ensure the preferred option maximises the net economic benefits to JEN customers.

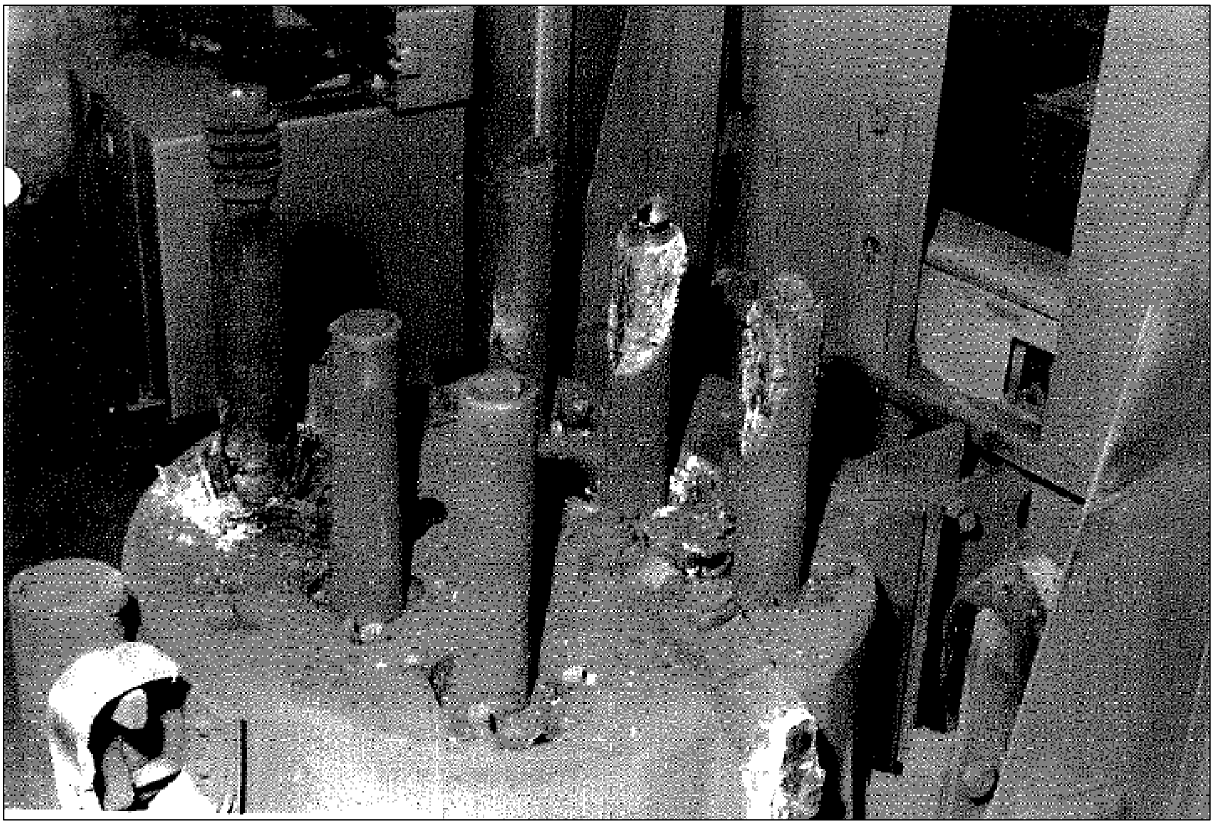
[11] Real 2024 dollars.

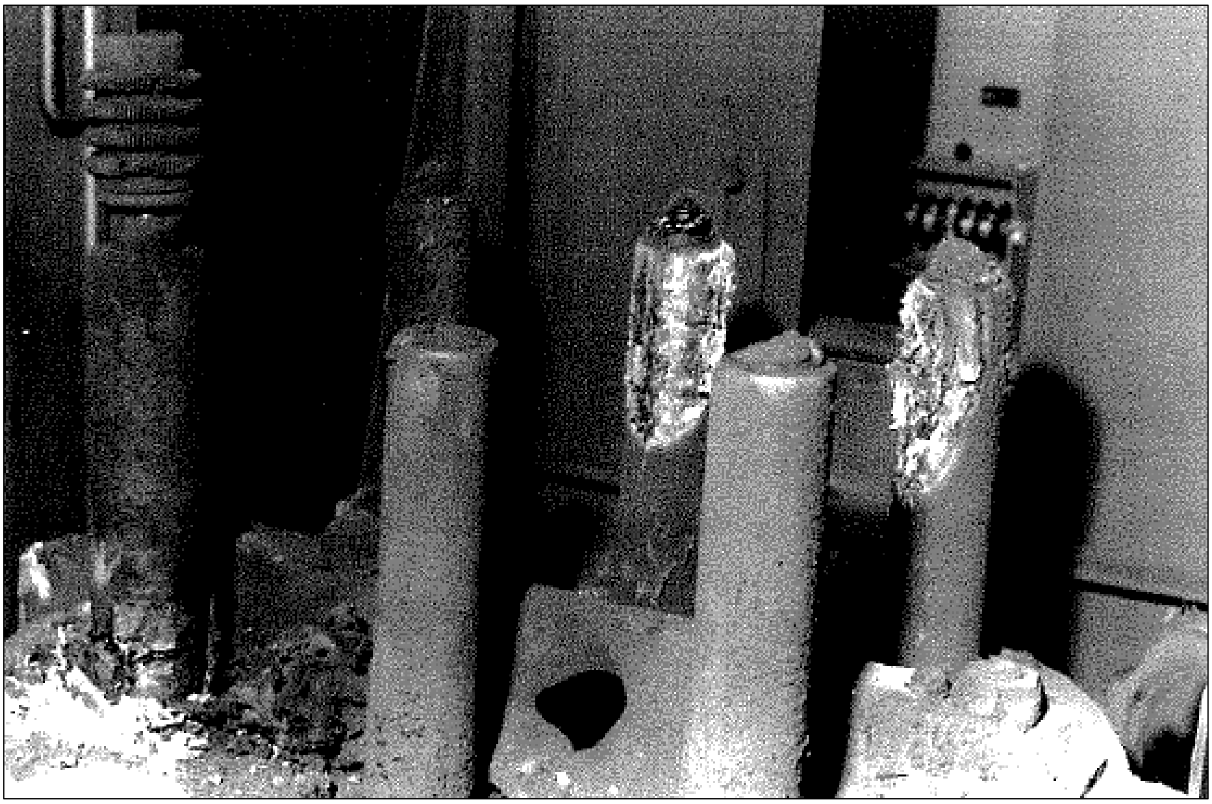
Appendix A: Catastrophic failure at FT zone substation

The photos below shows the 3 panels of the switchboard at FT zone substation which were destroyed because of a catastrophic circuit breaker failure.









Appendix B: Project Cost Estimates

The tables below provides the cost summary for stages 7 and 8.

Table C1-0: Direct Cost Breakdown for EP Conversion Stage 7

Description	Cost
Direct Delivery Cost	$23,590,035
Overheads	$6,416,948
Total Project Cost	**$30,006,983**

Table C1-1: Direct Cost Breakdown for EP Conversion Stage 8

Description	Cost
Direct Delivery Cost	$13,519,872
Overheads	$4,899,807
Total Project Cost	**$18,419,679**