Jemena Electricity Networks (Vic) Ltd

East Preston (EP) Conversion Stage 6

RIT-D Stage 2: Draft Project Assessment Report

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East Preston (EP) Conversion Stage 6
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Executive Summary

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

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

This Draft Project Assessment Report (**DPAR**) presents the Preston Conversion Program analysis of risk and outlines how this risk has been quantified. It outlines possible options for economically mitigating supply risks, and identifies the preferred option to manage the forecast supply risk and reduce safety risks in the area.

This East Preston Conversion Stage 6 Regulatory Investment Test for Distribution (RIT-D) DPAR:

- Utilises Jemena Electricity Network's (JEN's) 2020 load demand forecasts;
- Reports on a range of options for managing risk in the network; and
- Reflects on the potential for a combination of network and non-network credible options as assessed within the RIT-D Stage 1: non-network options screening report published on Jemena's website.

Identified Need

The Preston distribution network has operated since the 1920s with a primary voltage level of 6.6 kV from two 66 kV / 6.6 kV zone substations, Preston (**P**), and East Preston (**EP**), with EP consisting of two switch-houses, EP 'A' and EP 'B'. The surrounding zone substations at Coburg North (**CN**), Coburg South (**CS**) and North Heidelberg (**NH**) all operate at 22 kV. The assets at both P and EP zone substations were mostly installed in the 1960s, although some elements are significantly older. At both zone substations there were health and safety concerns for staff and the public due to the aging and poor condition of the plant with a high probability of failure and risk of step and touch potentials.

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

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

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

- Firstly, the need to protect workers and members of the public from harm caused by equipment failure and risk of step and touch potentials (Safety);
- Secondly, the need to maintain a reliable power supply to the residences and businesses that are dependent on the supply from this distribution network (Reliability); and

- Thirdly, the need to support customer growth in the Preston area by reducing the cost and complexity of connection for new residences and new businesses (Growth).

RIT-D Process

Distribution businesses are required to go through the Regulatory Investment Test for Distribution (RIT-D) process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $6 million.

The Australian Energy Regulator extended the RIT-D requirements to cover asset replacement projects in November 2017. When this updated RIT-D process was introduced, JEN's works to address the assets in poor condition in the Preston area had already commenced. The works are structured in stages, some of which are linked and must be completed before further work can be reassessed for prudency and changed if necessary. Such a point will be reached in November 2021 when the currently committed works are planned to be completed, which includes the conversion of four 6.6 kV distribution feeders from EP zone substation to 22 kV.

This report is based on the network that will exist in November 2021, and the needs identified for that network.

As required by the RIT-D process, JEN considered the credibility of potential non-network options as alternatives or supplements for the EP zone substation replacement works. A Non-Network Options Screening Report, published on Jemena's website on 27 August 2020, was prepared to establish whether the currently proposed works could be changed in scope or otherwise altered in response to a non-network solution.

Options Considered

The Non-Network Options Screening Report was predicated on the need for a non-network option to supply 26.3 MVA (the forecast consumer load supplied from EP zone substation). This would allow all of the assets in poor condition to be retired. It was also recognized that a non-network solution supplying 15.5 MVA may be viable if a part of the network is also renewed. Smaller non-network solutions would not provide sufficient capacity to be viable options.

Jemena has also developed a network development strategy to remediate the assets that are in poor condition and to meet the long term demand for electricity in the area. These include:

- Option 1: Do Nothing - Stopping the Preston Conversion Program at the end of P Stage 6 and running the remaining 6.6 kV network to failure;
- Option 2: Continue the Preston Conversion Program which includes a 2nd transformer at EPN;
- Option 3: Continue the Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN;
- Option 4: Delay Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to Fairfield (FF); and
- Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets.

Proposed preferred option

The options analysis identifies that:

- Option 2, continue the Preston Conversion Program which includes a second transformer at EPN, by proceeding with the next stage (EP Conversion Stage 6) is the preferred network option because it still meets the identified need and maximises the net market benefits compared to all other considered options; and,

- There are no credible non-network options, or combinations of non-network options with network options which could defer the need for the preferred network augmentation.

It should be noted that the preferred option (Option 2) was tested under a range of sensitivities including variations in costs, value of customer reliability and bus failure impacts. In each case, Option 2 was confirmed to provide positive economic benefits, and be the highest ranked option.

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

- Safety - Jemena did not undertake a quantified assessment of the safety benefits of each option, however these benefits are likely to be significant.
- Secondary asset failure - the supply risk associated with the replacement of secondary assets such as relays was also not quantified, as it was considered second order, and unlikely to affect the ranking of options.
- Reduction in network losses - the reduction in network losses associated with converting the old 6.6 kV network and to a 22 kV network was not quantified. This benefit is also expected to be significant, but was not quantified.

Jemena intends to proceed with the Preston Conversion Program as soon as possible to address the ongoing safety and supply reliability risks. The preferred option has a net market benefit of $386 million compared to the 'Do Nothing' option as shown in the Table ES-1 below.

Table ES–1: Summary of cost benefit analysis for preferred option

	'Do Nothing' Option 1 ($M, 2020 prices, discounted to 2020)	'Preferred' Option 2 ($M, 2020 prices, discounted to 2020)
Network improvements capital cost	-	(25) [1]
Cost of Expected Energy at Risk	(413)	(27)
Total Project Benefit	**-**	**386**

Submission and next steps

Jemena invites written submissions on this report from Registered Participants, interested parties, AEMO and non-network providers.

If no submissions are received on this report, this DPAR will be the final stage in the RIT-D Process and we will include the final decision in the 2021 Distribution Annual Planning Report. If submissions are received on this report, we will publish a Final Project Assessment Report (FPAR).

All submissions and enquiries should be directed to:

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Submissions should be lodged with us on or before 19 May 2021.

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

Following our consideration of any submissions on this Draft Project Assessment Report (DPAR), we will proceed to prepare a FPAR. That report will include a summary of, and commentary on, any submissions to this report,

[1] This is the total discounted costs for the remaining stages of the Preston Conversion Program. Noting EP Conversion Stage 6 project cost is estimated to be $7.9 million in June 2020 dollars.

and present the final preferred solution to address the identified need in the Preston area network. Publishing the FPAR will the final stage in the RIT-D process.

We intend to publish the FPAR by 31 May 2021. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2021 Distribution Annual Planning Report.

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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 Network (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 350,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum Demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or inter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network option	Any measure to reduce peak demand and/or increase local or distributed generation/supply options.
Probability of Exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($6M), in the National Electricity Market (NEM).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
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.

Abbreviations

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

1. Introduction

This section outlines the purpose of the Regulatory Investment Test for Distribution (RIT-D), Jemena's objective in undertaking its network planning role, and the structure of this draft project assessment report (DPAR).

1.1 RIT-D purpose and process

Distribution businesses are required to go through the Regulatory Investment Test for Distribution (RIT-D) process to identify the investment option that best addresses an identified need on the network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (the preferred option).

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated augmentation component capital cost of the most expensive potential credible option to address the identified need is more than $6 million. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need.

The Australian Energy Regulator extended the RIT-D requirements to cover asset replacement projects in November 2017. When the RIT-D process was introduced, works to address the assets in poor condition in the Preston area had already commenced. The works are structured in stages some of which are linked and must be completed before further work can be reassessed for prudency and changed if necessary. Such a point will be reached in November 2021 when the currently committed works are complete, which includes the conversion of four 6.6 kV distribution feeders from EP zone substation to 22 kV. The further stages are set out in the next chapter. This report is based on the network that will exist in November 2021 and the needs identified for that network.

As part of the RIT-D process a non-network options report must be prepared for those projects greater than $11m in value where a non-network solution may be potentially viable. Given the staging of the works in the Preston area, the currently proposed works could be changed in scope or otherwise altered in response to a non-network solution. Hence Jemena considered the credibility of potential non-network options as alternatives or supplements for the EP substation replacement works.

A non-network option would need to supply 26.3 MVA, the forecast consumer load supplied from EP zone substation. This would allow all of the assets in poor condition to be retired. A non-network solution supplying 15.5 MVA may be possible if a part of the network is also renewed. Smaller non-network solutions would not provide sufficient capacity to be viable options. The analysis found that a non-network solution could not (either on its own, or in combination with a network solution) provide a viable alternative. The Non-Network Options Screening Report published on Jemena's website provides a summary of this analysis.

This document is Jemena's draft project assessment report (DPAR) for the East Preston Conversion Stage 6 project which is the next stage of the Preston Conversion Program. In accordance with the requirements of the National Electricity Rules, this report describes:

- the identified need in relation to the Preston network;
- consideration of potential for non-network options to address the identified needs;
- the credible options assessed that may address the identified need;
- the methodologies used to quantify market benefits;
- the net present value assessment results for the potential credible options assessed; and
- the technical characteristics of the proposed preferred credible option.

1.2 Objective

Jemena's objective in planning its electricity distribution network is to ensure that reliable distribution services are delivered to its customers at the lowest sustainable cost.

This report is stage two of the RIT-D consultation process. It follows on from our non-network options screening report and considers network, non-network and hybrid options based on that report.

2. Background

This section provides an overview of the Preston supply area, describes the general arrangement of the East Preston network supply area and gives a brief overview of the network limitations. The assessment is based on Jemena's Load Demand Forecasts completed in 2020.

2.1 Network Supply Arrangements

Jemena Electricity Networks (Vic) Ltd (Jemena) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena 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 6,900 kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to around 330,000 homes and businesses for a number of 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 asset failure and risks associated with step and touch potential. JEN undertook Condition Based Risk Management modelling to rank the replacement of high risk plant items, and this prioritized the decommissioning of the P zone substation (which was completed in 2018) followed by the decommissioning of the EP zone substation (noting that EP consists of two switch-houses, EP 'A' and EP 'B').

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

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

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

In December 2017 all the remaining P feeders were transferred away from the old P zone substation allowing the decommissioning process to begin, and a new 66 kV / 22 kV zone substation (Preston (PTN)) to be constructed. In 2018 the old P zone substation was decommissioned, and the new PTN zone substation was constructed on the same site which was commissioned with two new 66 kV / 22 kV 20/33 MVA transformers in March 2020. The new PTN zone substation provides improved 22 kV capacity and leaves EP as one of the last two remaining 6.6 kV zone substations in the JEN's network, supporting the residual 6.6 kV assets in the East Preston area, supplying approximately 4,900 consumers.

Based on Jemena's 2020 Load Demand Forecasts Report, EP switch-house 'A' experiences maximum demand during summer, with:

- 50% probability of exceedance (PoE) maximum demand forecast to remain fairly constant, 9.9 MVA in 2021, dropping slightly to 9.6 MVA by 2027.
- 10% PoE maximum demand is also forecast to remain fairly constant from 10.6 MVA in 2021 to 10.2 MVA in 2027.

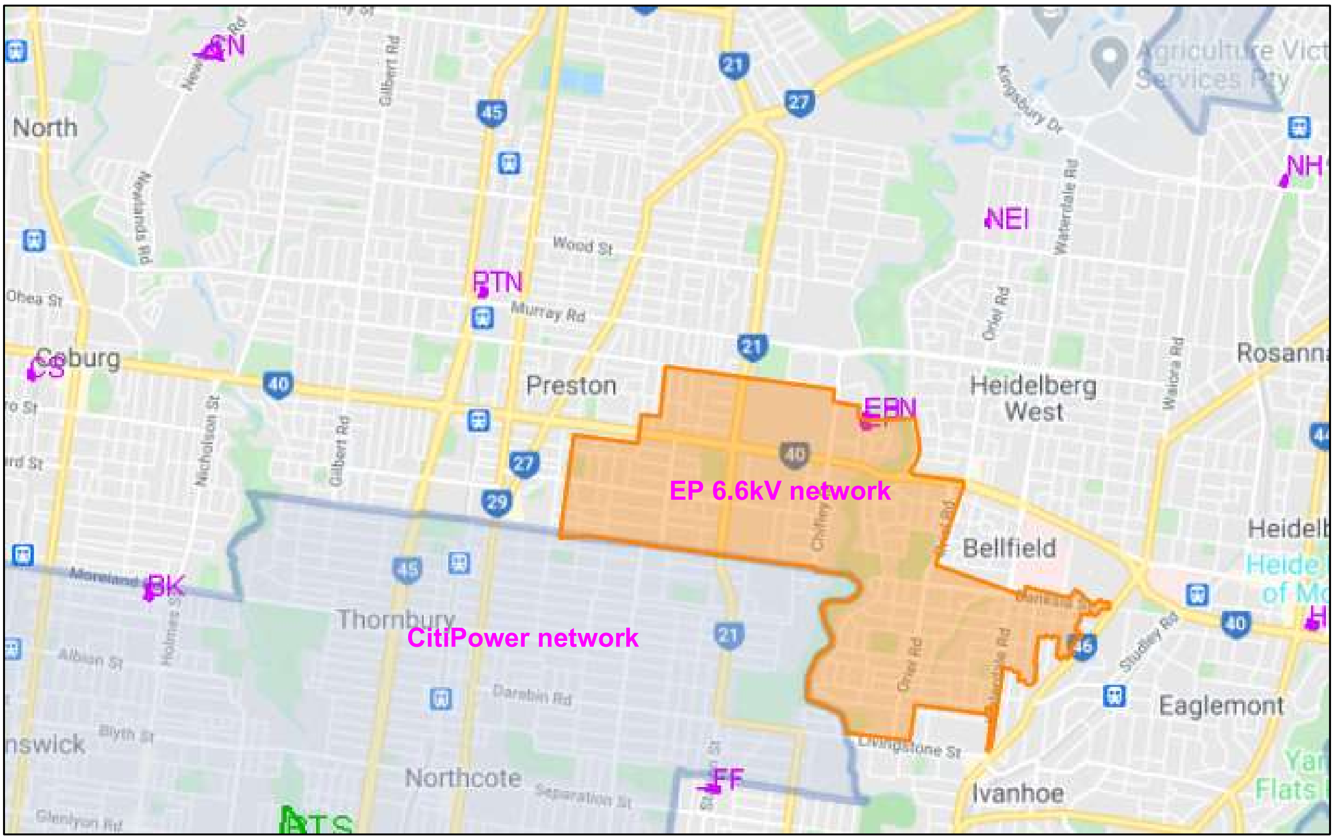
EP switch-house 'B' is forecast to experience maximum demand during summer, with:

- 50% PoE maximum demand forecast dropping slightly from 14.0 MVA in 2021, to 13.6 MVA by 2027.
- 10% PoE maximum demand is also forecast to decrease slightly from 15.2 MVA in 2021 to 14.7 MVA in 2027.

2.2 General Arrangement

Figure 2–1 shows the remaining East Preston 6.6 kV (EP) supply area as it currently stands including the surrounding 22 kV network supply areas of East Preston 22 kV (EPN), Preston (PTN), Coburg North (CN), Coburg South (CS) and North Heidelberg (NH).

Figure 2–1: Current East Preston Supply Area



3. Identified Need

Jemena has identified the East Preston distribution network as a priority for investment based on three key needs:

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

In line with the purpose of the regulatory investment test for distribution (RIT-D), as outlined in Clause 5.17.1 (b) of the National Electricity Rules, the identified need to address the Preston area supply limitation is an increase in the sum of customer and producer surplus in the National Electricity Market (NEM); that is an increase in the net economic benefit. This net economic benefit increase is driven by reducing the cost of expected unserved energy (predominantly by a change in the amount of involuntary load shedding in this case) through capacity and reliability augmentation, and balancing this benefit against each development option's cost to identify the optimal augmentation solution and timing.

However, the primary need in this case is related to minimising the safety risks for Jemena employees, and the public. Jemena's approach is to categorise the risk it into three categories (intolerable, As Far As Practicable (AFAP) and tolerable). The AFAP principle recommends risk reduction measures be implemented unless the cost, time, or trouble of the risk reduction measures is grossly disproportionate to the benefit gained from the reduced risk.

Consistent with the AFAP principle, Jemena has undertaken this program with the objective of minimising risks relating to the aging and deteriorated asset in the East Preston Supply Area. In the short term, Jemena is assessing whether there are any cost-effective risk mitigation controls (i.e. inhibiting the feeder circuit breaker auto reclose functions to reduce potential electrical stresses similar to the risk mitigation measures implemented at P Zone substation before it was decommissioned) which can be considered to reduce and minimise the risks highlighted above until the identified need is addressed. Based on the risk mitigation controls applied at P Zone substation the costs associated with these actions will be small compared to the cost of expected unserved energy associated with failure of the aged equipment and therefore these costs have not been included in the calculation of net economic benefit.

The risk to Jemena employees and the public, arising from potential major failure of the aging asset is considered to be significant, and hence the benefits of the Preston Conversion Program which removes this risk entirely, would also be significant.

Consistent with the AFAP principle and as is standard practice within the electricity sector, the safety benefits have not been quantified as part of this analysis. Nonetheless, there are real benefits associated with reducing the safety risks inherent in the Do Nothing situation.

These benefits should be considered as additional evidence which confirm the ranking of options.

3.1 First Identified Need - Safety

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

3.1.1 Condition of Plant

Although established in the 1920s, EP substation underwent extensive refurbishment in the early 1960s, therefore the average year of installation of the major equipment, including transformers indoor and outdoor circuit breakers and buses, is 1964. Based on JEN's Asset Class Strategies and with the application of JEN's Condition Based

Risk Management modelling using inputs from condition testing and monitoring, the major equipment (primarily the circuit breakers and buses) at EP are assessed to be at critical point with a very high probability of failure. The results demonstrate the switchgear and circuit breakers at EP (Type J18 and OLX) are at risk of increased failures and have an increased probability of a catastrophic failure.

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

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

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

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

- JEN PL 0039 Circuit Breakers Asset Class Strategy
- JEN PL 0042 Transformers Asset Class Strategy
- ELE PL 0029 Preston Area Network Development Strategy

In addition to the deteriorated condition of primary equipment at EP, the secondary equipment (e.g. relays, DC batteries etc.) are also operating well beyond their engineering life and are installed on asbestos type panels. Further details on the deteriorated condition of secondary assets are documented in JEN Zone Substation Protection & Control Equipment Asset Class Strategy (document number JEN PL 0021). It is also expected that over the coming years there will be an increase in maintenance costs for repair and condition monitoring at EP zone substation as the assets reach end of life.

3.1.2 Credible Solution Requirements

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

3.2 Second Identified Need - Reliability

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

- Directly measures customer (economic) outcomes associated with future network limitations;
- Provides a thorough cost-benefit analysis when evaluation network or non-network augmentation options; and,
- Estimates expected unserved energy which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a value of customer reliability ($/MWh).

Jemena uses this approach to identify, quantify and prioritise investment in the distribution asset. Typically, the expected unserved energy is calculated through understanding the load at risk for each zone substation. This is normally calculated through modelling load at risk under system normal condition and if any single item of equipment was out of service (called a normal minus one or N-1 scenario). A credible non-network solution should maintain a level of supply reliability which is consistent with Regulatory obligations. Hence, the minimum capacity of a solution would be how to deliver sufficient capacity to supply all load under a N and N-1 network reliability scenario in which the annualised cost of expected unserved energy at risk exceeds the annualised cost of augmentation.

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

3.2.1 Load Forecasts

The actuals demand and forecasts for EP 'A' and EP 'B' are shown below in Figure 3-1 and Figure 3-2. The forecasts for the supply area show that the maximum expected demand for EP 'A' is 10.6 MVA and for EP 'B' is 15.2 MVA for the summer 10% PoE in 2021. It is noted the forecast demand at EP zone substation is relatively flat between the 2021 and 2030 period. These forecasts include known spot loads where a customer has made an enquiry or application but do not include potential spot loads that may arise, as these are likely to exceed the capacity of the 6.6 kV system and hence are likely to be supplied from the more remote 22 kV system (discussed further in Section 3.2.4).

Figure 3–1: EP 'A' Demand Forecasts

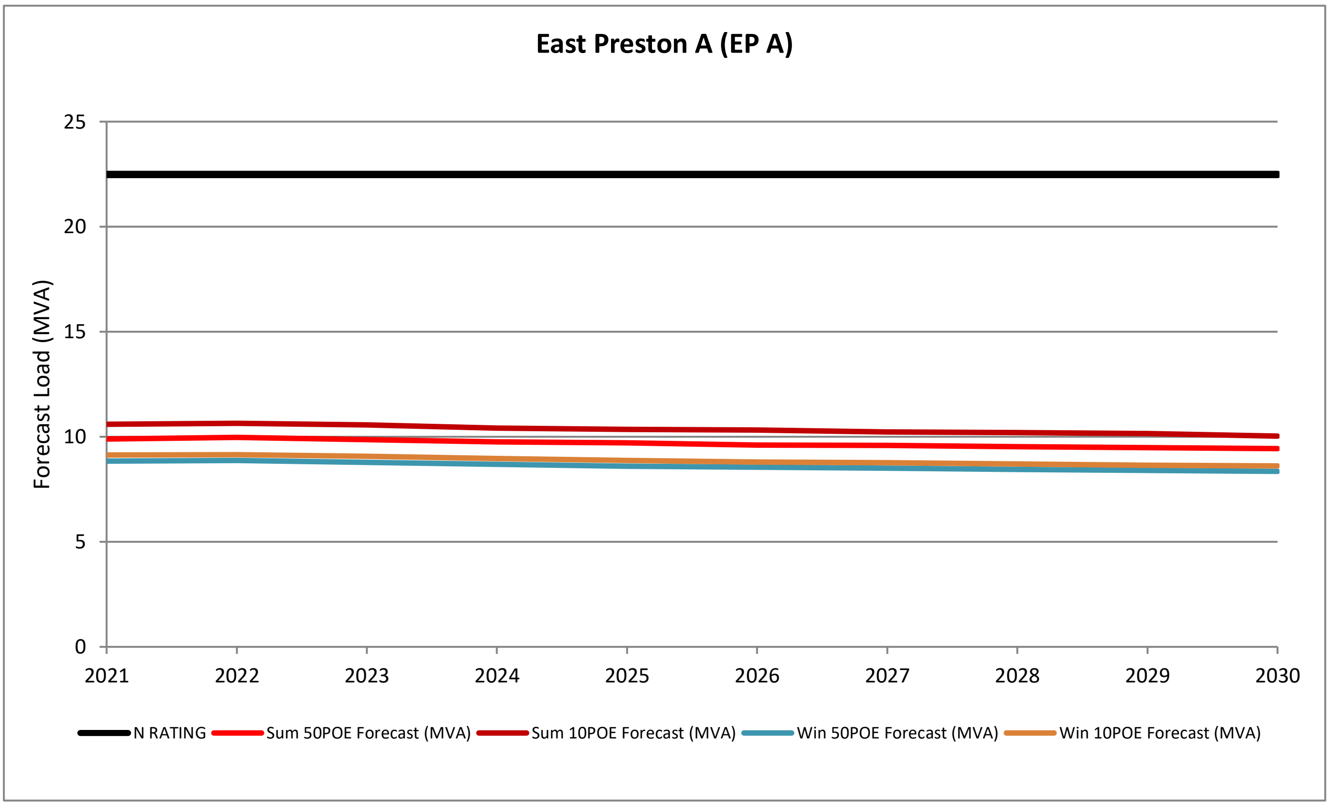
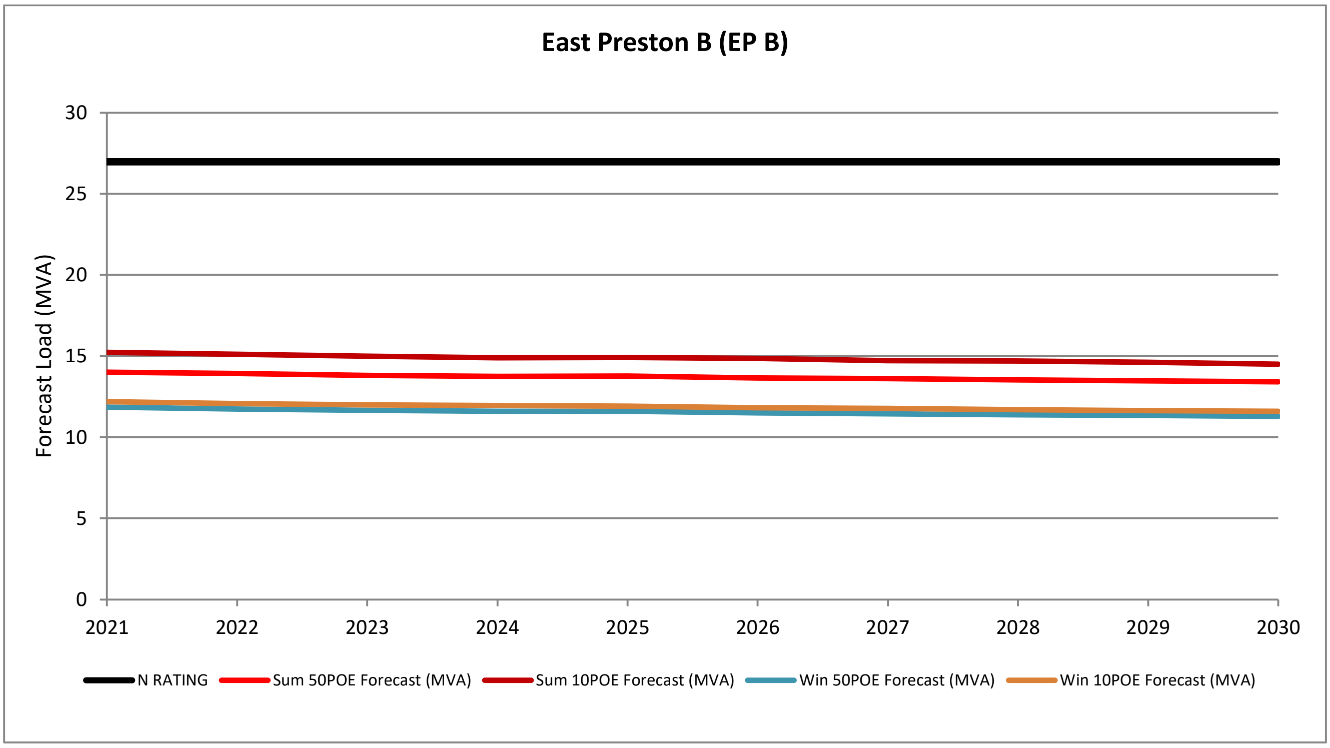


Figure 3–2: EP 'B' Demand Forecasts



3.2.2 Zone Substation Capacities

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

Based on the preferred staging of works, the overall capacities presented across the Preston area are summarized below in Table 3–1.

Table 3–1: Preston Area Capacity (for preferred staging of works) for preferred network option

Zone Substation	Stage (planned in service date)			
	EP Stage 5 (Nov' 2021)	EP Stage 6 (Nov' 2022)	EP Stage 7 (Nov' 2023)	EP Stage 8 (Nov' 2024)
EP 'A'	N Rating = 22.5 MVA N-1 cyclic Rating = 22.5 MVA Load transfer capacity = 0 MVA	Decommissioned	Decommissioned	Decommissioned
EP 'B'	N Rating = 27 MVA N-1 Cyclic Rating =28.5 MVA Load Transfer Capacity = 0 MVA	N Rating = 27 MVA N-1 Cyclic Rating = 28.5 MVA Load Transfer Capacity = 0 MVA	N Rating = 27 MVA N-1 Cyclic Rating = 28.5 MVA Load Transfer Capacity = 0 MVA	Decommissioned
PTN	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Cyclic Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA
EPN	N Rating = 33 MVA N-1 cyclic Rating = 0 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA	N Rating = 66 MVA N-1 Rating = 38 MVA

3.2.3 Credible Solution Requirements

To meet reliability requirements, credible solutions would be required to achieve a N-1 planning scenario. Table 3–2 shows the forecast load required to be supplied and to assist in developing project staging, possible staging scenarios with the current network contributions, the forecast load and the gap that would form the minimum load for a credible solution.

Table 3–2: Credible Solution Capacity Requirements (2021)

SCENARIO	FORECAST LOAD (MVA)	CURRENT NETWORK CONTRIBUTION (MVA)	CREDIBLE SOLUTION CONTRIBUTION (MVA)
Decommissioning of EP ‘A’ and EP ‘B’	25.8	0	25.8
Scenario - Decommissioning of EP ‘A’ transformer and associated equipment	EP ‘A’: 10.6 EP ‘B’: 15.2 Total: 25.8	EP ‘A’: 0 EP ‘B’: 15.2+0=15.2 Total: 15.2	10.6
Scenario - Decommissioning of EP ‘B’ transformer or associated equipment	EP ‘A’: 10.6 EP ‘B’: 15.2 Total: 25.8	EP ‘A’: 10.6+0=10.6 EP ‘B’: 0 Total: 10.6	15.2

By November 2021 following the planned completion of EP Stage 5, the transfer capability between EP ‘A’ and EP ‘B’ switchhouse will reduce to zero. Hence the load transfers between the two switchhouse does not impact the assessment, and the load at risk at the time of maximum demand would be 10.6 MVA for EP ‘A’, and 15.2 MVA for EP ‘B’.

3.2.4 Potential Growth

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

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

Other significant developments in the wider Preston area include:

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

- The North East Link project has earmarked the North portal supply is to be located near Lower Plenty Rd as one of their operational supply location which is within the JEN distribution boundary. The closest and most cost effective 22 kV supply point to the North portal operational supply is from the North Heidelberg zone substation. The customer demand during construction, and ongoing operational supply requirement for the operation of the new road assets is significant.

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

3.2.5 Credible Solution Requirements

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

4. Assumptions relating to identified need

In accordance with clause 5.17.1(b) of the National Electricity Rules, Jemena's augmentation investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

To achieve this objective, Jemena applies a probabilistic planning methodology that considers the likelihood and severity of critical network conditions and outages. The methodology compares the forecast cost to consumers of losing energy supply (e.g. when demand exceeds available capacity) against the proposed augmentation cost to mitigate the energy supply risk. The annual cost to consumers is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR). This is then compared with the annualised augmentation solution cost.

To ensure the net economic benefit is maximised, an augmentation will only be undertaken if the benefits, which are typically driven by the reduction in the cost of expected unserved energy, outweigh the cost of the proposed augmentation to reduce the unserved energy. Augmentation is not always economically feasible and this planning methodology therefore carries an inherent risk of not being able to fully supply demand under some possible but rare events, such as a network outage coinciding with peak demand periods. The probabilistic planning methodology that we apply is further detailed in our Distribution Annual Planning Report.

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

- Network asset ratings; and
- Network outage rates.

4.1 Network asset ratings

Although established in the 1920's, EP Zone Substation underwent extensive refurbishment in the early 1960's, therefore the average year of installation of the major equipment, including transformers, indoor and outdoor circuit breakers and buses, is 1964. From JEN's Asset Class Strategies (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 discussions 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):

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

Additionally, it should be noted that the secondary assets at EP Zone Substation, such as protection relays, batteries, chargers and communication equipment, are also in a deteriorated condition, with associated risk to the ability to supply loads in the area. The impact of this supply risk has not been quantified within this appraisal as it is considered to be secondary to the impact of transformer, switchgear and bus failure. Nonetheless, it should be noted that the appraisal of options would be further supported by modelling of this risk.

Switchgear

JEN's Condition Based Risk Management (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. CBRM develops a Health Index for each asset based on a scale from 0 to 10. Values of health index in excess of seven represent serious deterioration with a high probability of asset failure.

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 in Figure 4–1.

Figure 4–1: CBRM Health Index

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

The CBRM modelling indicates that on average the health index results (as of 2019) for most of the circuit breakers and buses at EP are greater than 7 and will have experienced further deterioration by 2023. The result indicates that the 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[2]. 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 are provided in Table 4–1 and Table 4–2 below.

Table 4–1: CBRM Result Summary EP (Switch House A)

Equipment	No. of equipment	Average Age (years)	Expected Life (years)	Health Index forecast (derived from CBRM)	
				2019	2023
6.6 kV bus tie CB	2	53	50	6.7	7.8
6.6 kV feeder and cap bank CB	9	50	45	7.3	8.7
6.6 kV transformers CB	3	51	48	6.7	8.0
66 kV bus tie CB	2	52	45	7.4	8.9
6.6 kV buses	3	51	50	9.9	11.5

[2] JEN PL 0039 Zone Substation Circuit Breaker Asset class strategy.

Table 4–2: CBRM Result Summary EP (Switch House B)

Equipment	No. of equipment	Average Age (years)	Expected Life (years)	Health Index forecast (derived from CBRM)	
				2019	2023
6.6 kV bus tie CB	2	51	50	6.8	7.8
6.6 kV feeder and cap bank CB	8	48	45	7.3	8.4
6.6 kV transformers CB	5	51	48	7.6	8.7
6.6 kV buses	3	51	50	7.6	8.9

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 by Select Solution, which demonstrated that the DDF values on section of the EP switchgear of up to and exceeding 5%, this 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

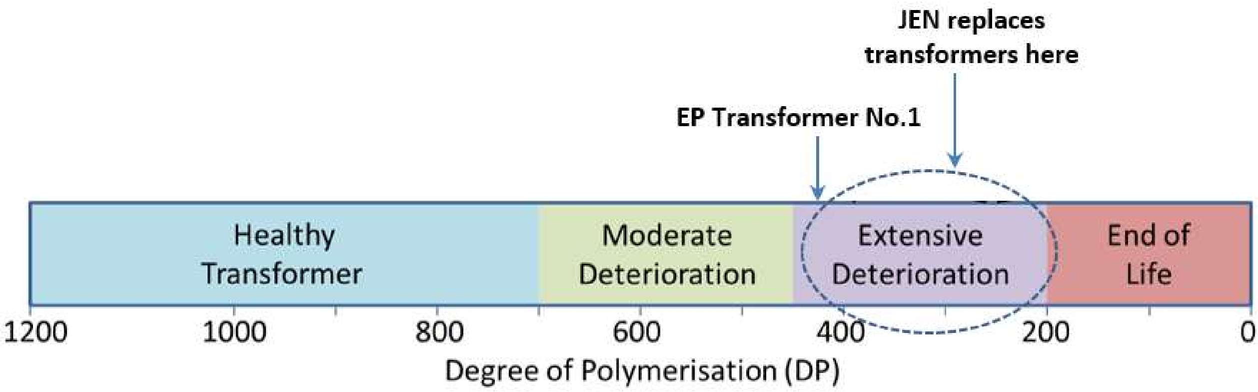
In 2004, the EP Zone Substation No. 1 66/6.6 kV transformer was replaced with a 66/11/6.6 kV unit, manufactured in 1962 and relocated from Braybrook (BY) zone substation.

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 2013 for the EP transformer No.1 are provided in Figure below. The results do not account for the DP value variation throughout the winding, therefore the actual DP value is now expected to be less than 400 for EP No.1 transformer, which indicates the transformer is at the end of its life.

Figure 4–2: Transformer Condition Scale



The transformers at EP zone substation undergo a condition based monitoring regime, including the DP assessment outlined above. The current Condition Monitoring Index for the transformer at EP is shown in Table 4–3 and demonstrates that EP transformer Nos 1, 3 and 4 are within the extensive deterioration range and in need of urgent retirement. However, EP transformer No.2 is relatively new (11 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 4–3: Transformer Condition Monitoring Index

Equipment	Age (years)	Health Index forecast (derived from CBRM)	
		2019	2023
EP transformer No.1	56	6.3	7.3
EP transformer No.2	11	1.0	1.3
EP transformer No.3	58	7.6	8.0
EP transformer No.4	59	6.4	7.2

4.1.1.1 Secondary Plant

In addition to the primary plant assets deteriorating condition, the secondary plant (e.g. protection relays, CT's and VT's) 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 also 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 slower 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 and the isolation of all feeders will result in a greater number of customers being off supply. Given the high 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 catastrophic failure.

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

4.2 Network outage rates

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

Probability of EP bus unavailability:

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

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

In reference to both the historic data and the CBRM model health index results (which indicates that the bus and circuit breakers are well deteriorated), the following probability assumptions have been applied in the economic assessment.

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

There are three 6.6 kV buses on EP 'A', therefore the probability of bus unavailability is (1/30) x 3 x (6/52) = 1.15% p.a. The same calculation applies to EP 'B', which also has three 6.6 kV buses.

EP transformer and switchgear failure rates:

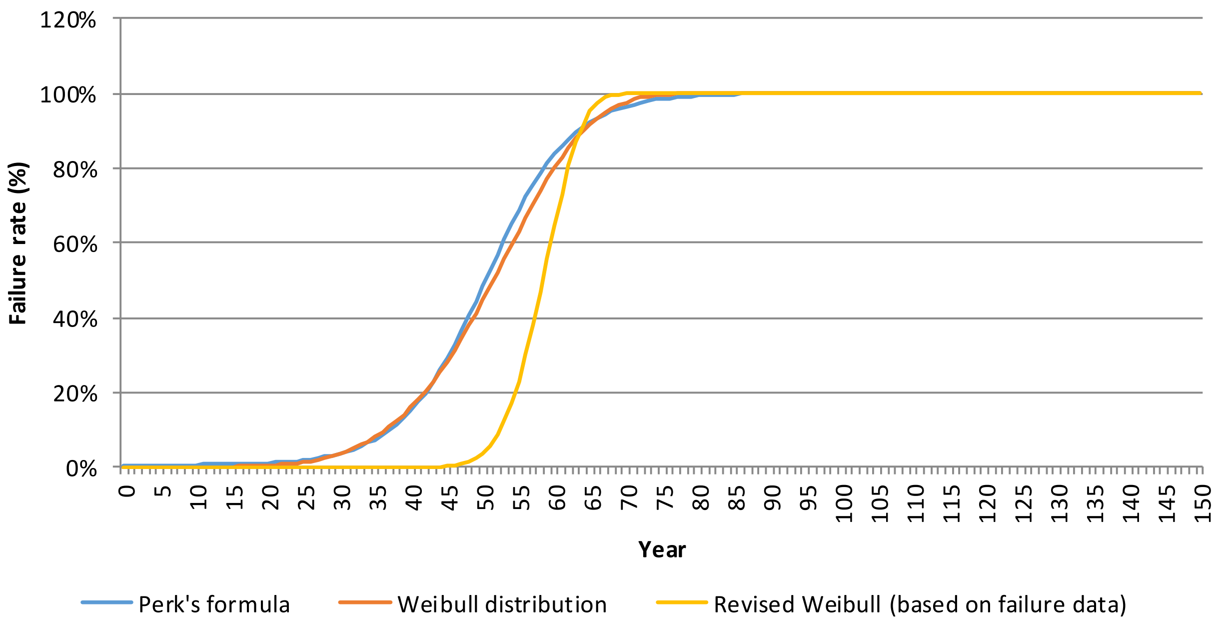
The probability of failure of the EP transformers and switchgear is based on predictions of remaining life taken from our CBRM assessments. Distribution curves were fitted to the data to establish a probability of failure curve. This was then compared to Perk's formulae as a sense check.[3]

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 EP switchgear. Adding data for similar switchgear at other zone substations did not provide a better distribution fit and were discarded.

Figure 4–3 shows the cumulative distribution curve for 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 6.6kV 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.

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

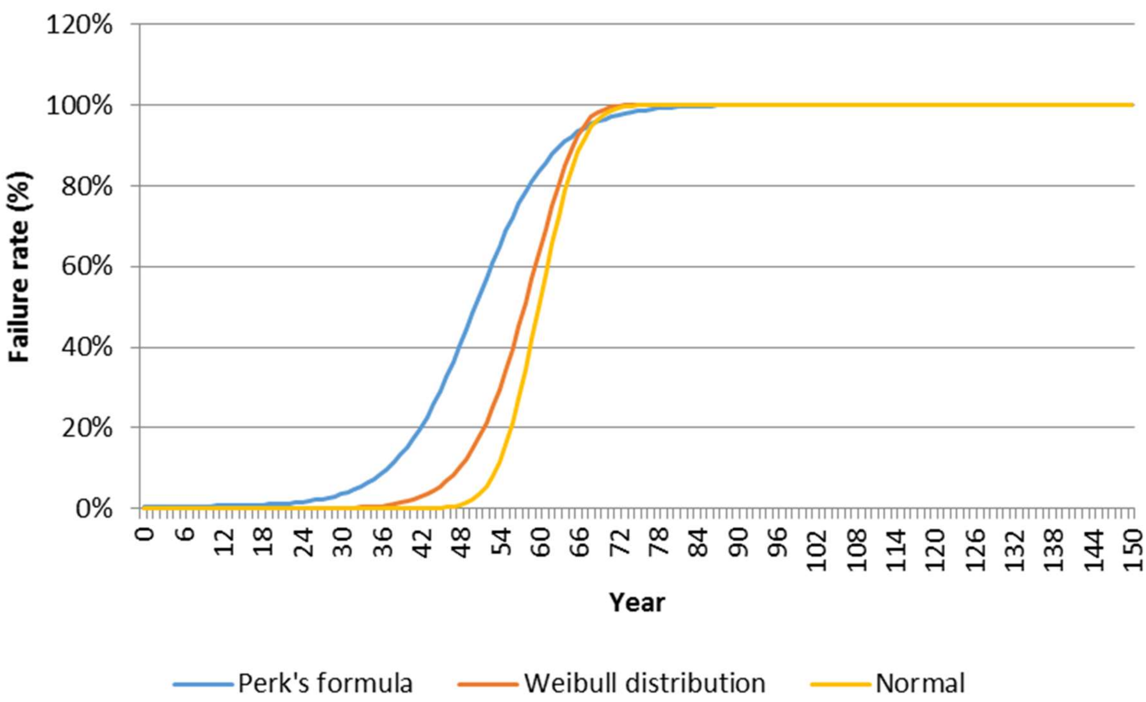
Figure 4–3: EP Switchgear failure curve



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

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

Figure 4–4: EP Transformer Failure Curve



5. Screening for non-network options

5.1 Types of non-network options considered

Potential non-network options that could meet the project objectives (as envisaged in the AER (Guidelines Section 7.1)) were considered based on two alternatives, Generation or storage, and Demand Management. Each of these, and the limitations imposed by the current customer profile, are discussed below.

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 embedded or co-generation is that it can significantly increase the fault current levels on the network, particularly on the 6.6kV network where the existing fault levels are already close to the fault current rating of the substation and Regulatory limits (e.g. Victoria Electricity Distribution Code). 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 Preston, 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 (i.e. to displace the entire load currently served by 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 to achieve large demand side solutions. The 2017 breakdown of customers in Preston is shown below in Table 5–1.

Table 5–1: 2017 Preston Customer Breakdown

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

The updated figures (June 2020) for each zone substation are shown below in Table 5–2.

Table 5–2: 2020 Preston Customer Breakdown

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

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

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

Figure 5–1: EP ‘A’ Customer Contribution to Peak

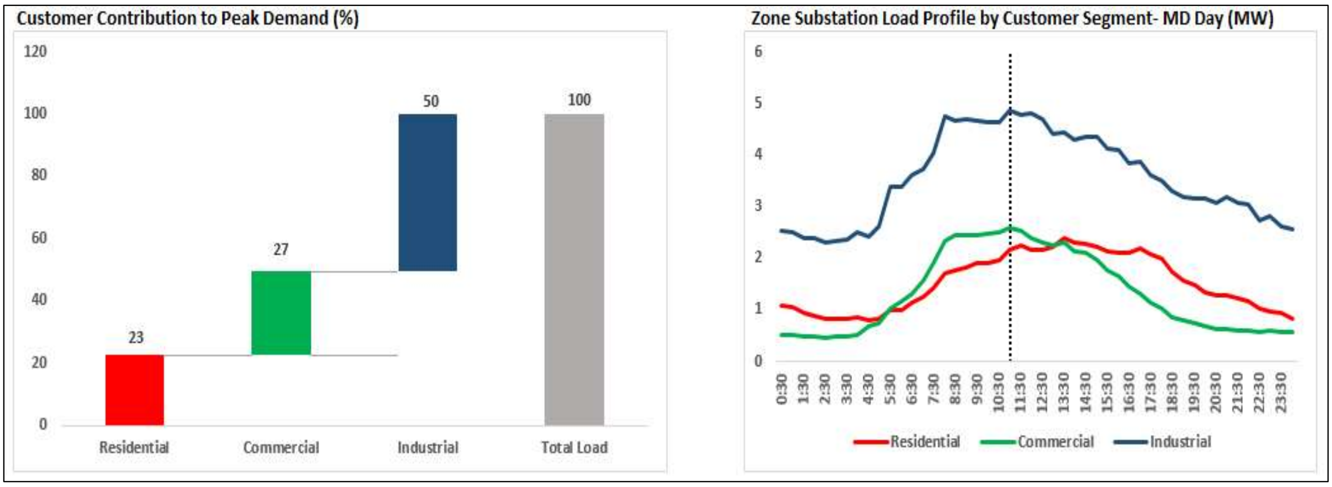


Figure 5–2: EP 'B' Customer Contribution to Peak

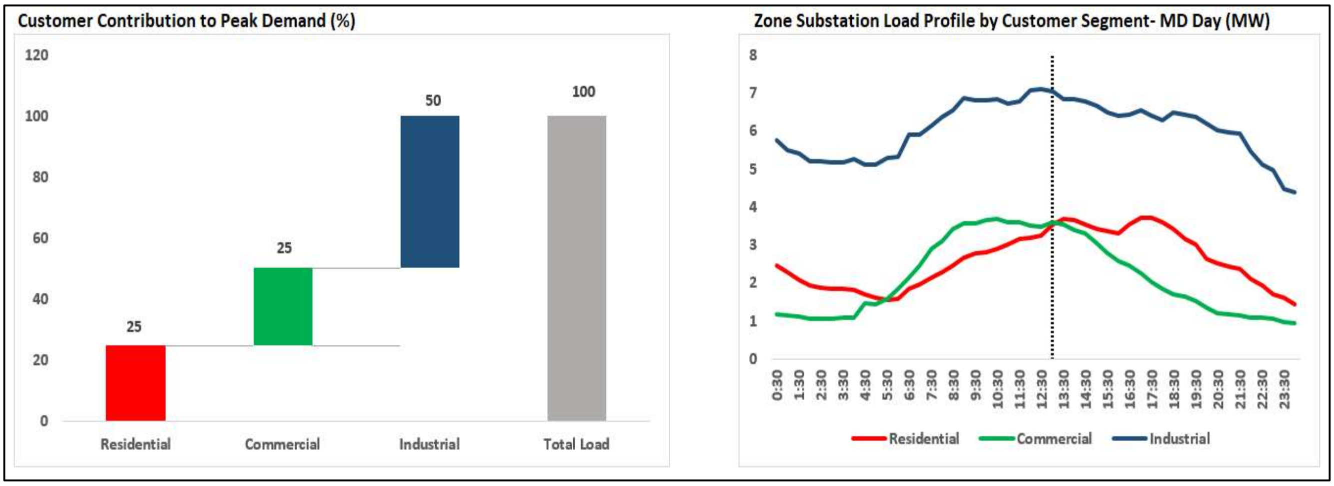
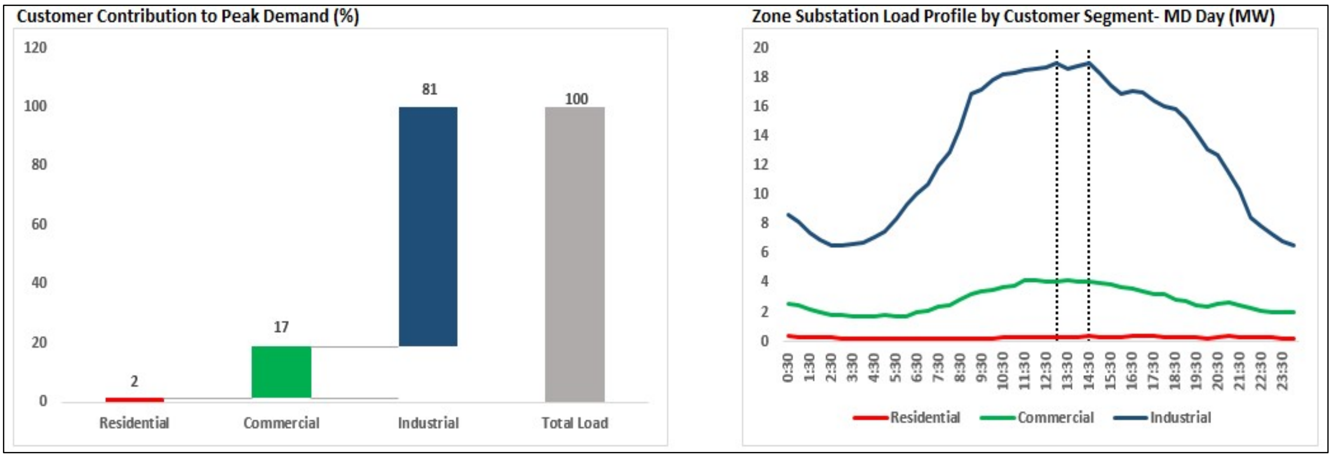


Figure 5–3: EPN Customer Contribution to Peak



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

5.2 Credible Scenarios

The National Electricity Rules requires RIT-D project proponents to investigate whether a non-network option (or combination of non-network measures) is capable of avoiding the need for investment in a network solution or at least allowing a smaller network investment to meet the identified need.

Potential non-network scenarios are:

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

Scenario 1
Meeting the identified need in its entirety through a non-network solution would require measures capable of meeting maximum forecast summer energy requirements (26.3 MVA) with a level of redundancy to cover this need when the largest single source of power fails.

Scenario 2

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

Consistent with the National Electricity Objective (NEO) to maintain a safe and reliable supply to customers, a network solution ultimately requires zone substation EPN to have a minimum of two transformers. This reflects that the second new 33 MVA EPN transformer will replace a total of four existing EP transformers (total capacity 76.5MVA) in order to provide sufficient minimum capacity to replace the existing EP 6.6kV transformers.

The timing of the second transformer (2022) is currently set to allow the conversion of the EP 'B' feeders to 22kV (2023) and the subsequent decommissioning of the EP 'B' substation. The installation of the second transformer could be avoided by a non-network solution that matched the difference between the current transfer capacity of the system when operating under a N-1 condition (0 MVA) and the forecast load. This value is approximately the load currently supplied by EP 'B' (15.5 MVA). The non-network screening criteria is applied in the next section with these generation requirements or savings in mind.

5.3 Assessment approach and findings

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

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

Figure 5–4 shows the rating scale we have applied for assessing non-network options.

Figure 5–4: Assessment Rating Criteria

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

The NNOSR (East Preston (EP) Conversion Stage 6 Non-network Options Screening report) 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 5–5 shows the assessment of non-network options against the RIT-D criteria. The assessment shows that a credible non-network option was not identified (considered both in isolation, and in combination with network solutions). Section 5.4 summarises each non-network option in more detail.

Figure 5–5: Assessment of non-network options against RIT-D criteria

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

1.1 Gas turbine power station				
1.2a Generation using renewables (Solar)				
1.2b Generation using renewables (Wind)				
1.3 Dispatchable generation (large customer)				
1.4 Large customer energy storage				
2.0 Demand Management options				
2.1 Customer power factor correction				
2.2 Customer solar power systems				
2.3 Customer energy efficiency				
2.4 Demand response (curtailment of load)				

5.4 Non-network assessment commentary

5.4.1 Generation and storage

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

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

Identified need – Reduces safety and reliability risks of running old plant beyond end of life. Capable of meeting identified need through provision of multiple gas generators. Fails to reduce cost and complexity of connection for new developments (**Partially met**).

Technical – Significant constraints and barriers to deployment of equipment to generate a minimum of 26.3 MVA in a dense urban environment (e.g. obtaining planning permits, local community concerns, adequately managing the environmental impacts). In addition, Jemena cannot establish the availability of a suitable high pressure gas pipeline in the locality that is essential for this type of generation. Further, the solution would be dependent on a single fuel source, gas. Multiple high pressure gas sources are not available in the area, meaning that a gas turbine solution could not maintain a safe and reliable supply to customers. Due to the 6.6 kV fault level limitations at EP zone substation, buses EP ‘A’ and EP ‘B’ were separated. Installing generators would result in an increase in fault levels which could exceed Code Limits under N and N-1 conditions (**Not met**).

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

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

Overall – Not a potentially credible option.

- **Generation using renewables solar (1.2a)**

Identified need – Reduces safety and reliability risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. We have no information on current solar generation by customers but estimate that the generation of 15.5 MVA using solar is likely to require more than 230 thousand square meters of land (https://www.quora.com/How-much-land-is-required-to-setup-a-1MW-solar-power-generation-Unit-1). Devoting this amount of land to energy production in a dense, urban environment is not feasible. As noted in Section 5, solar installations in EP provide a relatively small capacity of 1.8 MW. In addition, the generation profile of solar power may not align to the consumption profile of consumers. Fails to reduce cost and complexity of connection for new developments (**Not met**).

Technical – While it is technically feasible to use this well understood and applied technology for this type of power generation, there are significant constraints to the deployment of a solar facility to generate either 15.5 MVA or 26.3 MVA in this locality. These include zoning, planning and environmental constraints given the land requirements and the lack of evidence of the availability of land for this purpose. In addition solar generation alone does not provide the base-generation required (**Not met**).

Commercial – Costs of this type of generation are unlikely to be commercially viable or comparable with the costs of network alternatives. The solarshare 1 MW solar project in Canberra (https://solarshare.com.au/solar-farm-project/greenfield-project/) is costing $3 million and in the Preston environment purchasing large areas of land is likely to be a significant investment. This is unlikely to be cost effective when compared to the network alternatives (**Not met**).

Timing – Planning process and nature of the investment and likely objectives, together with design requirements (both for the generators and any required 6.6 kV connections to EP) mean this is unlikely to be completed in the timeframe required (**Not met**).

Overall – Not a potentially credible option.

- **Generation using renewables wind (1.2b)**

Identified need – Reduces safety and reliability risks of running old plant beyond life. Unlikely to meet or meaningfully contribute to the identified need. We estimate that a 2 MW wind turbine would require 6000 sq.m, and a 15.5 MVA wind turbine would require approximately 49 thousand sq.m (https://sciencing.com/much-land-needed-wind-turbines-12304634.html). Devoting this amount of land to energy production in a dense, urban environment is unlikely to be feasible. Fails to reduce cost and complexity of connection for new developments (**Not met**).

Technical – It is unlikely there is adequate site available in terms of elevation and wind conditions for wind generation within a densely urban suburb. The planning constraints and environmental factors involved in securing planning permission for using land for this purpose are very significant and the use of land for this purpose unlikely to be allowed (**Not met**).

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

Timing – The requirement to coordinate the installation of generation across a relatively large number of industrial power consumers together with likely planning requirements mean this is unlikely to be completed in the timeframe required (**Not met**).

Overall – Not a potentially credible option.

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

Identified need – Reduces safety and reliability risks of running old plant beyond life. Presently there is only one industrial HV customer supplied by EP consuming up to 0.4 MVA during peak loading periods. It's unlikely that this small number of industrial customers is consuming sufficient energy for this type of generation to provide a viable non-network option. The practical difficulties of coordinating generation efforts for a large number of small consumers are too great for this to be viable. Fails to reduce cost and complexity of connection for new developments (**Not met**).

Note: Jemena's *2019 Distribution Annual Planning Report* (Section 5.9.4) on customer proposals reports that:

In 2019, Jemena has received three connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this low level of enquiries to be a reflection of:

• The nature of the JEN network, which services the north east of greater metropolitan Melbourne, where there is limited availability of physical space for a significantly sized embedded generator.

• Underlying weaker energy and maximum demand growth in the Victoria region.

• A preference for smaller scale embedded generation, particularly roof top solar, for which the JEN network has seen an ongoing increase in installed capacity.

Technical – This type of generation is technically feasible within existing industrial sites but would face planning and technical constraints particularly due to the current high fault levels at EP (**Not fully met**).

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

Timing – Planning process and nature of the investment and likely objectives, together with design requirements (both for turbines and any required 6.6 kV connections to EP) mean this is unlikely to be completed in the timeframe required (**Not met**).

Overall – Not a potentially credible option.

Large customer energy storage (1.4)

The responses to this option (1.4) are similar to option 1.3. The overall finding that this is not a potentially credible option is driven by the relatively small power requirements per industrial customer and the need to coordinate efforts across many power users – this is likely to be time consuming and difficult to achieve. In addition, the costs associated with battery storage to manage peak demand and therefore reduce the scope of the non-network project are likely to be high in relation to the marginal costs for a full network solution.

Overall – Not a potentially credible option.

5.4.2 Demand Management/Efficiency

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

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

Identified need – Reduces safety and reliability risks of running old plant beyond life. This option is unlikely to meet the identified need because of the absence of very large industrial power users where this type of action could result in significant power savings. Fails to reduce cost and complexity of connection for new developments (**Not met**).

Technical – This type of saving is technically feasible for industrial/commercial users on a certain type of contract and is achievable. However, the magnitude of the reduction required (minimum of 15.5 MVA) is less than one half of current maximum demand (26.3 MVA), which is not able to be met by an improvement in power factor alone. In addition, a 10 MVA of embedded generation would face planning and technical constraints (**Not fully met**).

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

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

Overall – Not a potentially credible option.

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

Identified need – Reduces safety and reliability risks of running old plant beyond life. In 2019, solar household penetration in Australia is on average 22% of the country's total electricity (https://www.cleanenergycouncil.org.au/resources/technologies/solar-energy). Satellite imagery suggests that the proportion for the EP catchment is unlikely to exceed this average figure. Based on an average solar generation capacity of 3 kW per installation, approximately 5,400 installations would be required to provide 16.3 MVA capacity (26.3 MVA demand – 10 MVA of embedded generation), which exceeds the total number of customers at EP of 4,866. Currently, as noted in Section 5 solar installations in EP provide a relatively small capacity of 1.8 MW. This rate of take up is not considered to be achievable. This solution also fails to reduce cost and complexity of connection for new developments (**Not met**).

Technical – This option is technically feasible and the technology well understood and tested. 10 MVA of embedded generation would face planning and technical constraint **(Not fully met**).

Commercial – Achieving a greater than average solar take up would require a financial incentive and to achieve the level of take up for this option to be potentially credible would require a very high subsidy. The estimated cost of 10 MVA embedded generation is unlikely to be commercially viable (**Not fully met).**

Timing – There is uncertainty over whether this could be achieved given the large number of customers that would need to install solar (**Not fully met**).

Overall – Not a potentially credible option.

- **Customer energy efficiency (2.3)**

Identified need – The assessment for this option is similar to Option 2.2. Each of JEN's approximately 4,866 customers at EP would have to reduce consumption by approximately 62% during the summer peak period to achieve a 16.3 MVA reduction (16.3 MVA / 26.3 MVA = 62%). This scale of reduction is considered unrealistic even if accompanied by significant subsidies to incentivise customers to do this (**Not met**).

Technical – This option is technically feasible and the type of efficiencies required achievable if sufficient customers are willing to invest in such measures (fully met).

Commercial – Unclear that this is commercially feasible. (not fully met).

Timing – This type of mass action would be difficult to promote and implement and unlikely to be completed in the timeframe required (**Not fully met**).

Overall – Not a potentially credible option.

- **Demand response (curtailment of load) (2.4)**

This option has a similar assessment profile to options 1.3 and 1.4. All essentially rely on the actions of a small number of high consumption users. There is no evidence that suitable very large users who might be persuaded to curtail load exist within the relevant supply area, and hence this is unlikely to meet the identified need. In addition, this option is unlikely to be commercially feasible or achievable within the intended timing of the network solution.

Overall – Not a potentially credible option.

6. Network Options considered in the RIT-D

This section outlines the credible options that have been considered in the RIT-D, and outlines the proposed works associated with each credible option.

As previously noted in this report, the works to address the needs in the Preston area had already commenced. Works competed to date are shown in Table 6–1. EP Stage 5 is committed and currently in progress with a planned in-service date of November 2021.

Table 6–1: Preston Area Network Program

Stage(s)	In service date	Completed works
P Stage 1	Nov 2008	Conversion of P feeders and distribution substations
EP Stage 1 & 2	Nov 2008	Conversion of EP feeders and distribution substations
P Stage 2	Nov 2009	Conversion of P feeders and distribution substations
P Stage 3	Dec 2012	Conversion of P feeders and distribution substations
EP Stage 3	Nov 2015	New 66/22kV single transformer EPN zone substation
P & EP Stage 4	Nov 2016	Conversion of P & EP feeders and distribution substations
P Stage 5	Sept 2017	Conversion of remaining P feeders and distribution substations
P Stage 6	Mar 2020	Decommission P zone substation & establish new 66/22kV two transformers PTN zone substation
EP Stage 5	Nov 2021	Conversion of EP ‘A’ feeders and distribution substations

Prior to committing to the next stage to progress with the conversion of EP ‘A’ feeders and distribution substations, a review was undertaken that resulted in a 2020 business case that confirmed the plan and staging of the required works. The business case considered the following options:

- Option 1 – Do Nothing - Stopping the Preston Conversion Program at the end of P Stage 6 and running the remaining 6.6 kV network to failure
- Option 2 – Continue the Preston Conversion Program which includes a 2nd transformer at EPN
- Option 3 – Continue the Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN
- Option 4 – Delay Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to Fairfield (FF)
- Option 5 – Undertake like for like replacement of the remaining EP 6.6 kV distribution assets.

This review confirmed the preferred option was to continue the Preston Conversion Program as described below in Table 6–2.

Table 6–2: Preferred Network Solution (Staged)

Stage(s)	In service date	Cost estimate (real June 2020 dollars)	Anticipated works
EP Stage 6	November 2022	$7.9M	Decommission of EP ‘A’ zone substation and install 2nd transformer at EPN zone substation
EP Stage 7	November 2023	$13.4M	Conversion of EP ‘B’ feeders and distribution substations
EP Stage 8	November 2024	$8.5M	Conversion of EP ‘B’ feeders and distribution substations. Decommission of EP ‘B’ zone substation.
TOTAL		$29.8M	

6.1 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 Jemena’s customers. The cost of involuntary load shedding is calculated using the value of customer reliability (VCR) which, for the Jemena electricity network, is currently estimated at $41,738/MWh (Real $2020), as described in Section 7.3.1.1.

The ‘Base Case’ option gives the basis for comparing the cost-benefit assessment of each credible augmentation option. The base case is presented as a do nothing option, where we would continue managing network asset loading through involuntary load shedding and ‘Business as Usual” (BAU) maintenance but not initiate any augmentation project.

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

6.2 Option 2: Continue the Preston Conversion Program which includes a 2nd Transformer at EPN

As recommended in the Preston Area Electricity Network Development Strategy paper, this option is consistent with this strategy and continues the conversion of the East Preston area in stages to 22 kV. Under this strategy, the next stage is EP Stage 6.

For this report, the remaining stages of the Preston Conversion Program are summarised below at a high level. Further details can be found in ELE PL 0029 Preston Area Conversion Network Development Strategy document.

- EP Stage 6 – Decommission EP ‘A’ zone substation and install 2nd transformer at EPN zone substation
- EP Stage 7 – Convert EP feeders and distribution substations from 6.6kV to 22kV
- EP Stage 8 – Convert remaining EP feeders and distribution substations from 6.6 kV to 22 kV. Decommission EP ‘B’ zone substation.

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

- Maintain supply reliability to customers supplied from EP by addressing the physical asset condition 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;
- Manage the risk of significant loss of supply for the TTS-NH 66 kV line under single contingency condition with improved 22 kV transfer capability from EPN to restore supply by enabling the existing feeder automatic circuit reclosers to be utilised effectively; and
- Manage reliability risks associated with several 6.6 kV EP feeders in the area which are forecast to be overloaded and do not have sufficient transfer capacity under single contingency conditions.

6.3 Option 3: Continue the Preston Conversion Program and substitute EPN 2nd Transformer with New Feeders from PTN

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

Due to the relatively flat load forecast on EP zone substation over the next planning period, this option involves alternative works to provide the approximately 30 MVA of additional capacity required after EP Stage 5 to continue with the conversion works to retire EP as an alternative to option 2 (installing a 2^{nd} transformer and 22 kV bus at EPN during this stage of works).

Instead of establishing a second transformer 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 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 includes:

- EPN zone substations will remain as a single transformer station and therefore will have increased load at risk under N-1 conditions during peak loading periods with load transferred from EP. The forecast maximum demand on EPN during summer 2020 is 23.6 MVA with a transfer capacity away from EPN of 7.2 MVA, leaving up to 16.4 MVA of load at risk under single contingency condition during peak times.
- By extending the existing EPN feeders to help with the conversion, the current 22 kV feeder ties from EPN connecting to NH will be highly utilised. Therefore, this will significantly reduce any load transfer capability away from NH zone substation to EPN. This will result in significant supply risk placed on the TTS-NH 66 kV line under single contingency during peak loading periods. This risk could be managed with a new feeder from EPN, however EPN is currently a single transformer station with one 22 kV bus and therefore does not have any spare feeder circuit breakers that can be used to establish a new feeder.
- Operationally the new feeders from PTN extending into the EP area will be long and 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).

6.4 Option 4: Delay the Preston Conversion Program and substitute EPN 2nd Transformer with Load Transfer and Upgrade to Fairfield

With Fairfield (FF) zone substation being the only remaining 6.6 kV network on the JEN network, this option explores the possibility of transferring 15 MVA load from EP onto FF to avoid the need to add additional transformation capacity at EPN zone substation (i.e. installing a second transformer and 22 kV bus). This would then still allow the remaining works for the Preston conversion program to continue and enable EP zone substation to be retired. However, this option will place substantial supply risk on FF zone substation and its 6.6 kV feeders because there is no load transfer capability under single contingency events for both planned and unplanned as it will effectively be an islanded 6.6 kV network.

Under this option, due to the low capacity of the 6.6 kV network, four new 6.6 kV feeders would be required from FF zone substation in order to provide sufficient feeder capacity to the transfer 15 MVA from EP to FF. In addition to the feeder augmentation, the following upstream network augmentation would also be required to provide sufficient capacity to support for the additional load transferred onto FF:

- Replace the existing hot-standby transformer at FF with a new 12/18 MVA transformer; and
- Augment the BTS-FF 22 kV sub-transmission lines.

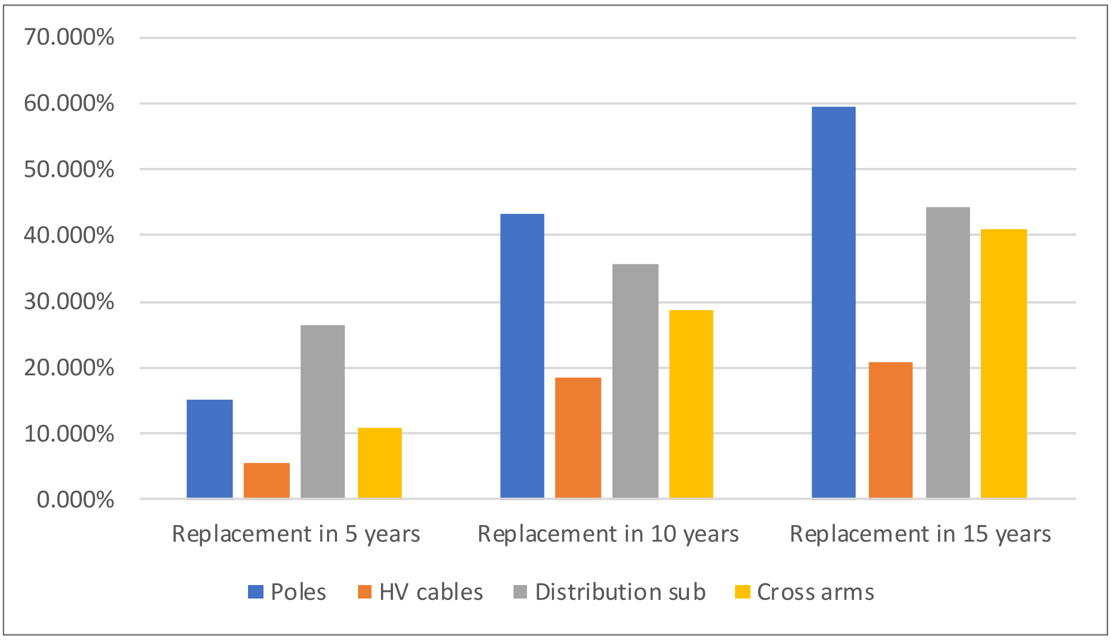
Due to the additional upstream works at FF, this option will also delay the retirement of EP zone substation out to 2026.

6.5 Option 5: Like for Like replacement of the remaining EP 6.6 kV Distribution Assets

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

The 6.6 kV distribution assets in the East Preston area were established over many decades dating back to as early as the 1920’s. Based on the age profiles of the assets, Figure 6-1 shows the 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 two. Generally, poles will not need to be replaced when a feeder is converted, unless they are found to be unserviceable.

Figure 6–1: EP distribution assets requiring replacement due to age over next 15 years



This option involves building a new 66/6.6 kV zone substation on a new site to enable the existing 6.6 kV loads from EP to be transferred away in order the existing EP assets to be retired. Jemena 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.

7. Market Benefit Assessment Methodology

This section outlines the methodology that Jemena has applied in assessing the market benefits associated with each of the credible options considered in this RIT-D. It describes how the classes of market benefits have been quantified and outlines why particular classes of market benefits are considered inconsequential to the outcome of this RIT-D.

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. Market benefits were calculated for first ten years, based on JEN's 2020 load demand forecasts. For the remainder of the appraisal period, zero demand growth has been assumed.

7.1 Market benefit classes quantified for this RIT-D

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

The classes of market benefits quantified for this RIT-D include changes in:

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

7.1.1 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 event, 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 Jemena has calculated to be $41,738/MWh (Real $2020), based on using the AER's value of customer reliability review and applying Jemena's customer load composition.
- Jemena 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.
- Jemena has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D. The costs have been included in the net economic benefit assessments summarised in Section 8.

7.1.2 Timing of expenditure

The costs of credible options assessed in this RIT-D include the works required to complete the Preston Area Conversion Program (Option 2), and also, the works required to undertake a like for like replacement of 6.6kV asset (Option 5). All costs will be incurred by 2033. Option 1 – Do Nothing, involves stopping the Preston Area Conversion Program at the end of EP Stage 5 (assumed to have zero net increase in costs).

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

7.2 Market benefit classes not relevant to this RIT-D

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

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

7.2.1 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.

Jemena has assessed the potential for voluntary load curtailment in the Preston area. This assessment showed there was minimal potential for voluntary load curtailment to provide sufficient additional capacity to either replace a network solution or to enable a more economic network solution. Therefore, this market benefit was not quantified as it was considered to be not material with respect to differentiating between network options.

7.2.2 Changes in Load Transfer Capacity and Embedded Generators

The preferred scheme (Option 2) will remove the last remnants of the 6.6 kV network in the Preston Area. This will support increased load transfer capacity between the surrounding 22 kV network and the Preston Area. Since the preferred option is the only option to deliver significantly increased load transfer capacity, this market benefit would not alter the ranking of options and therefore was not quantified.

As outlined in Section 5, Jemena currently has no significant embedded generators (>1 MW) connected to the Preston zone that could help address the identified need.

Contracting embedded generation for network support is therefore not considered a credible option, and market benefits were not quantified.

7.2.3 Costs to Other Parties

The Preston Area need primary need relates to safety concerns, and the secondary need to reliability constraints. Neither of these concerns are linked to other parties. However, the tertiary identified need relates to the potential for growth in the Preston network. It is anticipated that as larger developments come on line in the 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) which would require this work this is considered to be a potential cost, which should not be included in the summary of benefits of the scheme. It is also noted that including this potential impact in the options assessment would not change the rankings of the options. Therefore, the market benefits associated with costs to other parties have not been quantified.

7.2.4 Option Value

The AER RIT-D 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 Preston conversion program, it is noted that the works completed to date are sunk costs, and, the primary need for the remaining stages of the program has been identified as a safety need. As explained in Section 3.1, a credible solution must enable the decommissioning of the major primary assets at EP 'A' and EP 'B', including transformers, switchgear and secondary equipment.

It is therefore considered that in this case, there is little (if any) value in retaining flexibility, given that the safety need requires decommissioning of the major assets at EP 'A' and EP 'B'. Jemena has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

7.2.5 Electrical Energy Losses

Reducing network utilisation, through network impedance or supply voltage changes in the 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 2 and Option 3, losses would be reduced by up to 9 times due to the higher operating voltage and less number of feeders required to supply the same amount of load. This would save consumers up to $0.5 million per year in payments for losses, although the actual saving would depend on the final network topography and the actual changes in network impedance.

Under Option 4 and Option 5, the losses would remain the same as a like for like replacement would retain the same voltage level and similar values of impedance in the network.

The consideration of electrical energy losses would not change the rankings of the options given the proportionality test. Therefore, the market benefits associated with electrical energy losses are not considered as part of this RIT-D, and have therefore been excluded from the market benefit assessments.

7.3 Valuing market benefits

Clause 5.17.1 of the NER requires that the RIT-D assessment is based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand. Since this RIT-D is driven firstly by a safety need, demand growth is not the major consideration. Nonetheless, as the second identified need, supply reliability has been quantified based on reference to the load demand forecasts. The Jemena demand forecasts for the Preston area presume very low growth over the appraisal period. Future supply developments are not expected to significantly impact the assessment results, preferred option or optimal timing of the project.

The Guidelines note that "*Where a change to a parameter or value in a central reasonable scenario yields or is likely to yield a change to the ranking of credible options by net economic benefit, the RIT-D proponent should adopt additional reasonable scenarios that reflect variations in that parameter or value*".

For this RIT-D, Jemena has assumed low demand growth as a base case. Testing higher demand growth scenarios would not be likely to change the ranking of credible options by net economic benefit, and therefore, alternative demand scenarios have not been tested.

7.3.1 Sensitivity analysis

Jemena critically assessed the parameters used in the base case and believes that the key variables applied in valuing the economic benefits are outlined in this section, and include:

- Value of customer reliability (VCR);
- Project costs; and,
- Asset failure rate assumptions.

Note, a discount rate of 6.09% has been applied in assessing the Net Present Value (NPV) assessment of credible options. The ranking of credible options is not sensitive to changes in the discount rate (as the majority of costs are incurred in the early years of analysis).

7.3.1.1 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.

In assessing the credible options to alleviate the impact of constraints on its network, Jemena applies VCR values based on the AER's value of customer reliability review and applying Jemena's customer load composition, comprising an approximate 32% residential, 44% commercial and 24% industrial split. JEN's composite VCR figure for 2020 is $41,738/MWh.

Sensitivities to the base VCR of ±10% have been considered, resulting in a low VCR sensitivity of $37,564/MWh and a high VCR of $45,912/MWh.

7.3.1.2 Project costs

The network project capital costs have been estimated by Jemena's internal estimation teams. Consideration has been given to recent similar augmentation projects and expected costs based on site specific construction complexities and industry experience. Disposal costs of the asset are included in the cost estimate. Resale value of the aged asset is estimated to be between $100k and $200k. 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 RIT-D. Project costs are presented in real 2020 dollars.

7.3.1.3 Asset failure rate assumptions

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

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

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

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

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

In order to test the sensitivity of the results to these assumptions, two alternative tests have been identified:

A. Optimistic case – The probability of a bus and/ or circuit breaker failure affecting multiple buses is 1 in 50 years, hence the per annum probability is (1/50) x 3 x (6/52) = 0.692% p.a.

B. Pessimistic Case - The probability of a bus and/ or circuit breaker failure affecting multiple buses is 1 in 30 years, but the time required to repair is 12 weeks, hence the per annum probability is (1/30) x 3 x (12/52) = 2.31% p.a.

8. 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 2021 to 2040.

Each potential augmentation option has been ranked according to its net economic benefit, being the difference between the market benefit and the costs within the assessment period.

8.1 Network limitations

8.1.1 Option 1 – Do Nothing (base case)

This option considers the impact of a 'Do Nothing' scenario, which would include no additional investment in the Preston distribution network (beyond the previously committed investment). The Preston Conversion Program is currently committed up until the end of EP Stage 5 which is planned for completion in 2021. Following this stage, the remaining 6.6 kV network from EP will be retained, and the 6.6 kV assets run to failure.

Involuntary load shedding would be expected under system normal and network outage conditions. The impact of the network limitations under the base case is presented in Table 8–1.

Table 8–1: Option 1 - Do Nothing Cost of Energy at Risk ($M, 2020 prices, undiscounted)

Year	EP 'A'	EP 'B'	EPN	TTS-NH	Total
2021	10.2	15.1	0.0	0.0	25.3
2022	10.2	15.0	0.7	0.0	26.0
2023	10.2	14.9	0.9	0.0	26.0
2024	10.0	14.8	1.1	0.2	26.1
2025	10.0	14.8	1.4	0.2	26.4
2026	9.9	14.7	1.7	0.2	26.6
2027	9.9	14.7	1.9	0.3	26.8
2028	9.9	14.6	2.3	0.3	27.1
2029	9.8	14.6	2.6	0.3	27.4
2030	9.8	14.5	3.0	0.4	27.7
2031	9.8	14.5	3.5	0.5	28.2
2032	9.8	14.5	4.0	0.5	28.8
2033	9.8	14.5	4.3	0.6	29.2
2034	9.8	14.5	4.6	0.7	29.6
2035	9.8	14.5	5.0	0.8	30.1
2036	9.8	14.5	5.5	1.0	30.7
2037	9.8	14.5	6.0	1.1	31.4
2038	9.8	14.5	6.6	1.3	32.2
2039	9.8	14.5	7.4	1.6	33.2
2040	9.8	14.5	8.3	1.6	34.1

8.1.2 Option 2: Continue the Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN

This option involves the completion of the proposed Preston Conversion Program, by continuing the remaining 6.6 kV to 22 kV conversion of the distribution network in the East Preston supply area. This option would not be expected to result in involuntary load shedding under system normal, however, there will be one year of involuntary load shedding under network outage conditions at EPN prior to the installation of 2nd transformer. The impact of the network limitations under Option 2 is presented in Table 8–2.

Table 8–2: Option 2 - Cost of Energy at Risk ($M, 2020 prices, undiscounted)

Year	EP ‘A’	EP ‘B’	EPN	TTS-NH	Total
2021	0.1	0.1	0.0	0.0	0.1
2022	0.1	0.1	0.7	0.0	0.8
2023	0.0	0.1	0.0	0.0	0.1
2024	-	0.1	0.0	0.0	0.1
2025	-	-	0.0	0.0	0.0
2026	-	-	0.0	0.0	0.0
2027	-	-	0.0	0.0	0.0
2028	-	-	0.0	0.0	0.0
2029	-	-	0.0	0.0	0.0
2030	-	-	0.0	0.0	0.0
2031	-	-	0.0	0.0	0.0
2032	-	-	0.0	0.0	0.0
2033	-	-	0.0	0.0	0.0
2034	-	-	0.0	0.0	0.0
2035	-	-	0.0	0.0	0.0
2036	-	-	0.0	0.0	0.0
2037	-	-	0.0	0.0	0.0
2038	-	-	0.0	0.0	0.0
2039	-	-	0.0	0.0	0.0
2040	-	-	0.1	0.0	0.1

8.1.3 Option 3: Continue the Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN

This option involves a change in scope to the proposed Preston Conversion Program, by substituting the second transformer at EPN with two new HV feeders from PTN, and continuing the remaining 6.6 kV to 22 kV conversion of the distribution network in the East Preston supply area. Involuntary load shedding would be expected under network outage conditions for EPN and TTS-NH 66 kV line. The impact of the network limitations under Option 3 is presented in Table 8–3.

Table 8–3: Option 3 - Cost of Energy at Risk ($M, 2020 prices, undiscounted)

Year	EP ‘A’	EP ‘B’	EPN	TTS-NH	Total
2021	0.1	0.1	0.0	0.0	0.2
2022	0.1	0.1	0.0	0.0	0.2
2023	-	0.1	0.7	0.0	0.8
2024	-	0.1	0.9	0.2	1.1
2025	-	-	1.1	0.2	1.3
2026	-	-	1.3	0.2	1.5
2027	-	-	1.5	0.3	1.8
2028	-	-	1.8	0.3	2.1
2029	-	-	2.1	0.3	2.4
2030	-	-	2.4	0.4	2.8
2031	-	-	2.7	0.5	3.1
2032	-	-	3.0	0.5	3.6
2033	-	-	3.4	0.6	4.0
2034	-	-	3.6	0.7	4.3
2035	-	-	3.8	0.8	4.6
2036	-	-	4.0	1.0	5.0
2037	-	-	4.3	1.1	5.4
2038	-	-	4.6	1.3	6.0
2039	-	-	5.0	1.6	6.6
2040	-	-	5.5	1.6	7.0

8.1.4 Option 4: Delay Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to Fairfield (FF)

This option involves a change in scope and delay to the proposed Preston Conversion Program, by substituting the second transformer at EPN with load transfer and upgrade to FF zone substation, and continuing the remaining 6.6 kV to 22 kV conversion of the distribution network in the East Preston supply area. Involuntary load shedding would be expected under network outage conditions for EPN and TTS-NH 66 kV line. The impact of the network limitations under Option 4 is presented in Table 8–4.

Table 8–4: Option 4 - Cost of Energy at Risk ($M, 2020 prices, undiscounted)

Year	EP ‘A’	EP ‘B’	EPN	TTS-NH	Total
2021	0.1	0.1	0.0	0.0	0.2
2022	0.1	0.1	0.0	0.0	0.2
2023	-	0.1	0.7	0.0	0.8
2024	-	0.1	0.9	0.2	1.1
2025	-	-	1.1	0.2	1.3
2026	-	-	1.3	0.2	1.5
2027	-	-	1.5	0.3	1.8
2028	-	-	1.8	0.3	2.1
2029	-	-	2.1	0.3	2.4
2030	-	-	2.4	0.4	2.8
2031	-	-	2.7	0.5	3.1
2032	-	-	3.0	0.5	3.6
2033	-	-	3.4	0.6	4.0
2034	-	-	3.6	0.7	4.3
2035	-	-	3.8	0.8	4.6
2036	-	-	4.0	1.0	5.0
2037	-	-	4.3	1.1	5.4
2038	-	-	4.6	1.3	6.0
2039	-	-	5.0	1.6	6.6
2040	-	-	5.5	1.6	7.0

8.1.5 Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets

This option considers the impact of a ‘Like for Like’ replacement’ scenario, which would involve replacing the existing 6.6 kV zone substation assets from EP with new 6.6 kV assets. The remaining 6.6 kV EP distribution network will be retained, and replaced through use of like for like replacement. Involuntary load shedding would be expected under network outage conditions. The impact is presented in Table 8–5.

Table 8–5: Option 5 - Cost of Energy at Risk ($M, 2020 prices, undiscounted)

Year	EP ‘A’	EP ‘B’	EPN	TTS-NH	Total
2021	0.1	0.1	0.0	0.0	0.2
2022	0.1	0.1	0.7	0.0	0.9
2023	-	0.1	0.9	0.0	1.0
2024	-	0.0	1.1	0.2	1.2
2025	-	0.0	1.3	0.2	1.5
2026	-	0.0	1.5	0.2	1.8
2027	-	0.0	1.8	0.3	2.1
2028	-	0.0	2.1	0.3	2.4
2029	-	0.0	2.4	0.3	2.7
2030	-	0.0	2.7	0.4	3.1
2031	-	0.0	3.0	0.5	3.5
2032	-	0.0	3.4	0.5	4.0
2033	-	0.0	3.6	0.6	4.2
2034	-	0.0	3.8	0.7	4.5
2035	-	0.0	4.0	0.8	4.9

2036	-	0.0	4.3	1.0	5.3
2037	-	0.0	4.6	1.1	5.8
2038	-	0.0	5.0	1.3	6.3
2039	-	0.0	5.5	1.6	7.0
2040	-	0.0	6.0	1.6	7.6

8.2 Economic benefits

Net economic benefits are the market benefits less the cost (negative benefit) to implement the credible option being considered. Table 8–6 shows the cost, net economic benefit, and the project ranking of each option relative to the Do Nothing option.

All feasible network options commence after the planned completion of EP Stage 5 in 2021. The feasible options have been ranked based on their present value of net economic benefit, which is the total benefits provided over the 2021-2040 period, minus the project cost to implement, operate and maintain the credible option being considered.

The assessment results show that the feasible option that maximises the net economic benefit is Option 2. This option includes decommissioning EP zone substation and installing a second transformer at EPN zone substation. This option is Jemena's proposed preferred option because it meets the identified need and maximises the net economic benefit compared to all the other options considered in this RIT-D.

Table 8–6: Net Economic Benefits of each option

Option	NPV Cost (Real $2020)	NPV of market benefits	Ranking
Option 1: Do nothing	-	-	5
Option 2: Continue with the current 6.6 kV to 22 kV Preston Conversion Program which includes a 2nd transformer at EPN	$25M	$386M	1
Option 3: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN	$23M	$332M	2
Option 4: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to FF	$35M	$321M	3
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$54M	$301M	4

8.2.1 Sensitivity Analysis

The key variables applied in valuing the economic benefits were considered to be:

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

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

1. Higher than expected costs (+30%), lower than expected VCR (-10%), longer bus failure repair times (2.31%); and,

2. Lower than expected costs (-30%), higher than expected VCR (+10%), lower probability of bus failure (0.69%).

This analysis demonstrated that the conclusions were not sensitive to the changes, as the ranking of the options remained constant as shown in Table 8–7 and Table 8–8 below.

Table 8–7: Scenario 1 - Net Economic Benefits of each option (high cost / low VCR / longer bus failure repair times)

Option	NPV Cost (Real $2020)	NPV of market benefits	Ranking
Option 1: Do nothing	-	-	5
Option 2: Continue with the current 6.6 kV to 22 kV Preston Conversion Program which includes a 2nd transformer at EPN	$32M	$639M	1
Option 3: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN	$30M	$592M	2
Option 4: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to FF	$45M	$576M	3
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$70M	$551M	4

Table 8–8: Scenario 2 - Net Economic Benefits of each option (low cost / high VCR / low probability failure)

Option	NPV Cost (Real $2020)	NPV of market benefits	Ranking
Option 1: Do nothing	-	-	5
Option 2: Continue with the current 6.6 kV to 22 kV Preston Conversion Program which includes a 2nd transformer at EPN	$23M	$282M	1
Option 3: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with new feeders from PTN	$21M	$222M	2
Option 4: Continue the 6.6 kV to 22 kV Preston Conversion Program and substitute EPN 2nd transformer with load transfer and upgrade to FF	$32M	$212M	3
Option 5: Undertake like for like replacement of the remaining EP 6.6 kV distribution assets	$49M	$194M	4

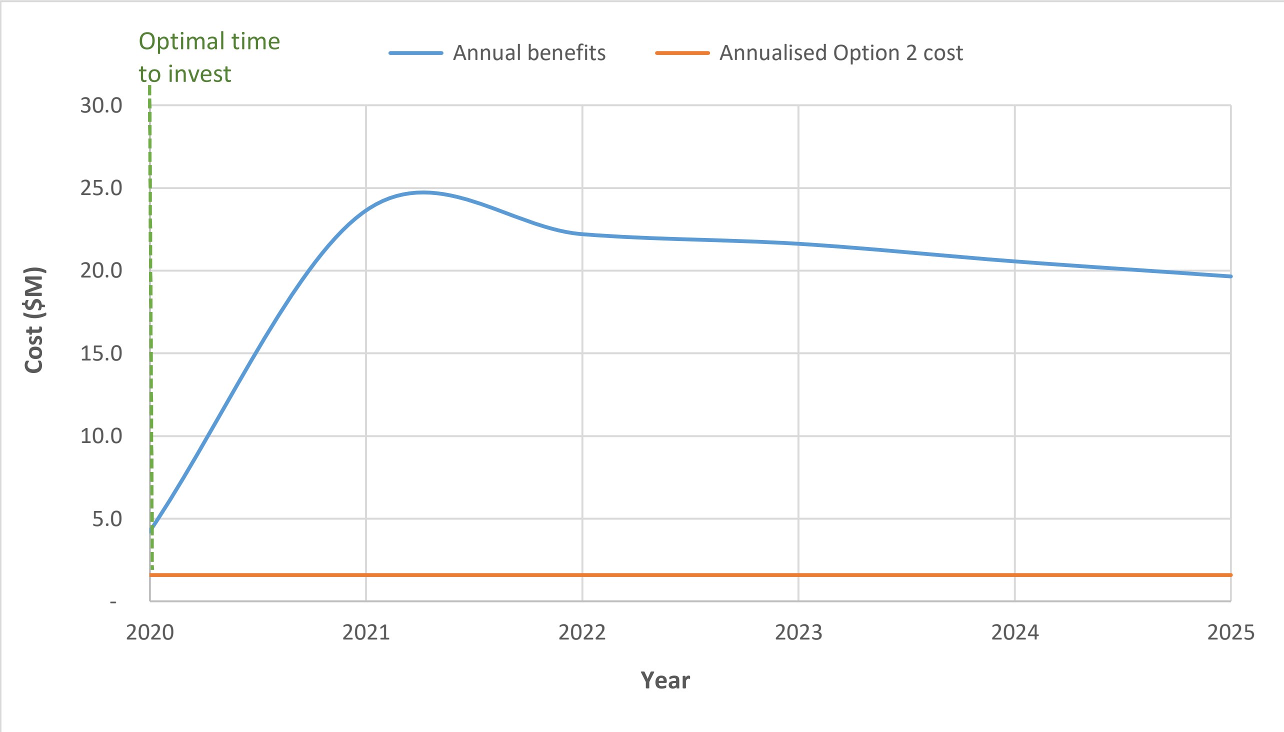
8.3 Preferred option optimal timing

The first identified need for this investment is to reduce the safety risks of the aging asset. Any delay in design or implementation of this investment would increase the safety risks, and therefore, alternative timings for investment have not been considered.

Further support for an early commencement is demonstrated by considering the benefits to reliability. To demonstrate this, 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 discount rate of 6.09% per annum.

Figure 8–1 below 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 8–1: Economic project timing for preferred option



9. Conclusions and next steps

The assessment outlined within this report shows that the primary limitations associated with the East Preston supply are the concerns around the safety of the aging asset at East Preston zone substation, the level of reliability provided by the aging asset, and the potential limitations for new customer connections caused by the restrictions of the 6.6 kV network.

9.1 Preferred solution

The assessment shows that the preferred solution is to continue with the Preston conversion program, by proceeding with the next stage (EP Conversion Stage 6) as the preferred network option.

It should be noted that Option 2 (the Preferred Option) was tested under a range of sensitivities including variations in costs, value of customer reliability and bus failure impacts. In each case, the preferred option was confirmed to provide positive economic benefits, and be the highest ranked option.

Prompt investment will enable Jemena to continue with the remaining Preston conversion program as a priority to address the ongoing safety and supply reliability risks. The remaining proposed project timing, costs and anticipated works for the preferred option is presented in Table 9–1.

Table 9–1: Preferred option – Preston conversion program remaining stages

Stages	In Service Year	Cost estimate	Anticipated works
EP Stage 6	2022	$7.9M	Decommission of EP 'A' Zone Substation & install 2nd transformer at EPN Zone Substation
EP Stage 7	2023	$13.4M	Conversion of EP feeders and distribution substations
EP Stage 8	2024	$8.5M	Conversion of EP feeders and distribution substations. Decommission of EP 'B' Zone Substation

9.2 Next steps

Jemena invites written submission on this report from Registered Participants, interested parties, AEMO and non-network solution providers.

All submissions and enquiries should be directed to:

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Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 7960

Submissions should be lodged with us on or before 19 May 2021.

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

Following our consideration of any submissions on this Draft Project Assessment Report (DPAR), we will proceed to prepare a Final Project Assessment Report (FPAR). That report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the identified need in the Preston area network. Publishing the FPAR will the final stage in the RIT-D process.

We intend to publish the FPAR by 31 May 2021. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2021 Distribution Annual Planning Report.