Jemena Electricity Networks (Vic) Ltd

Distribution Feeders

Network Development Strategy

ELE PL 0006

31 January 2020

An appropriate citation for this paper is:

EDPR 2021-2026
Distribution Feeders
Network Development Strategy
Our Ref: ELE PL 0006

Authorisation

Name	Job Title	Date	Signature
Reviewed by:			
	Customer and System Planning Manager	10/12/2019	
Approved by:			
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History

Rev No	Date	Description of changes	Author
1	30/11/2018	Initial document	
1.1	17/05/2019	Updates to include non-network options	
1.2	03/12/2019	Update based on latest input forecast and capex plan	
1.3	11/12/2019	Minor updates	
1.4	13/01/2020	Revised $ based on latest Capex Plan	

Owning Functional Area

Business Function Owner:	Asset Management

Review Details

Review Period:	Annual
NEXT Review Due:	09/12/2020

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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.
Contingency condition (or event)	Refers to the loss or failure of part of the network.
Feeder continuous rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Feeder cyclic rating	The permissible maximum demand to which a conductor or cable may be loaded on a daily basis for up to 90 consecutive days during the summer or winter period, taking into account the cyclic nature of the daily feeder load profile. Cable cyclic rating is equal to a multiple of 1.13 times the cable's continuous rating. Overhead conductor cyclic rating is equal to the conductor's continuous rating.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 338,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Non-network alternative	An alternative solution to growing customer demand, which does not involve augmenting physical network assets.
Overhead lines maximum safe loading limit on HV network (summer)	A maximum load limit on HV network under system normal operating condition determined under various environmental conditions where the conductor operating temperature is likely to exceed 100ºC where the conductor annealing effect is accelerated to an unacceptable level or statutory clearance limit is likely to be infringed.
Planning criteria	The methodologies, inputs and assumptions that must be followed when undertaking technical and economic analysis to predict emerging power transfer limitations.
Power quality	Refers to the fitness of electrical power for the consumer devices it is required to supply. The Victorian Electricity Distribution Code (VEDC) and National Electricity Rules (NER) set the power quality obligations for Jemena Electricity Network's (JEN) network operations.
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 ($5m), 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.
Underground cable maximum safe loading limit	A maximum load limit of the HV underground cable determined to be the cyclic rating under system normal operating condition.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	50% POE and 10% POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

ABBREVIATIONS

ACR	Automatic Circuit Reclosers
AER	Australian Energy Regulator
DAPR	Distribution Annual Planning Report
EDPR	Electricity Distribution Price Review
HV	High Voltage
JEN	Jemena Electricity Network
LV	Low Voltage
MD	Maximum Demand
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objectives
NER	National Electricity Rules
POE	Probability of Exceedance
PV	Photovoltaic
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code
CIC	Customer Initiated Capex

OVERVIEW

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena Electricity Networks (JEN) service area covers 950 square kilometres of northwest greater Melbourne and includes the Melbourne International Airport, which is located at the approximate physical centre of the network, and some major transport routes. The network comprises over 6,000[1] kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to over 338,000 homes and businesses for a number of energy retailers. The network service area ranges from Couangalt, 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. Refer to the attached maps of Jemena's service area in Appendix A and Appendix B, which also shows the zone substation supply areas with different growth rates.

Like all electricity distribution network service providers in Australia, Jemena Electricity Network (JEN) is a regulated business. It must comply with the National Electricity Rules (NER) and the National Electricity Law (NEL), including the National Electricity Objective. The Australian Energy Regulator (AER) is responsible for the economic regulation of the electricity transmission and distribution networks in the national electricity market (NEM). Regulated electricity network businesses must periodically apply to the AER to assess their revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules lay out the framework that the AER must apply in undertaking this role for distribution and transmission networks respectively. The frameworks require the AER to set a ceiling on the revenues or prices that a network can earn or charge during a regulatory period. The current regulatory period for the Jemena Electricity Network will end on 31 December 2020. Therefore, Jemena must make a submission for the regulatory period 2021-26.

This document provides an assessment of the capacity of the Jemena high voltage electricity distribution feeders to meet forecast customer demand. Where capital expenditure is planned during the 2021-26 regulatory period to address a capacity constraint, the project justification, options, recommendation, scope and cost and is provided within this document. This document forms part of the Jemena 2021-26 Electricity Distribution Price Review (EDPR) submission.

Jemena currently owns and maintains a total of 217[2] high voltage electricity distribution feeders. There are currently 121 high voltage electricity distribution feeders in Jemena network forecast to have load at risk under normal condition (N condition) and/or single contingency condition (N-1 condition), with 33 feeders are forecast to have significant load at risk, including 25 feeders which are forecast to exceed their maximum safe loading limit, by summer 2025/26 under 10% POE demand conditions. Based on the cost benefit analysis, Jemena proposes to address the load at risk for 26 feeders (18 feeders forecast above their safe loading limit and 8 feeders that have significant load at risk under N-1 condition) in the forthcoming regulatory period.

A further 7 feeders forecast to have significant load at risk will be addressed either by existing feeder transfers, proposed projects in the current regulatory period, or customer initiated capital (CIC) projects in the forthcoming regulatory period. The optimal timing for augmentation to address load at risk on the remaining 88 feeders was assessed to be beyond the forthcoming regulatory period.

In order to maintain a safe and reliable electricity supply to customers, Jemena proposes a total capital expenditure of $32.8 million (real $2019 with overheads)[3] across 16 projects during the 2021-26 regulatory period to address high voltage electricity distribution feeder capacity constraints.

Jemena has undertaken a number of demand management trials and is building internal capabilities and knowledge in these emerging areas so as to assess and implement non-network option (irrespective of the RIT-

[1] Does not include low voltage services

[2] Count excludes JEN-owned sections of Powercor's Saint Albans (SA) feeders.

[3] The total capex expenditure includes $0.3M in FY20 for six projects, and $0.9M in FY27 for two projects that are proposed to be completed by November 2026.

D threshold) where it is efficient to do so. At this point in time, there are a number of impediments such as high cost, firmness in demand response, market maturity in terms of technology and service providers that are proving challenges in non-network solution implementation. Jemena will continue to assess the viability of implementing non-network option to defer projects closer to the delivery. At this stage there are currently no proponents that has offered a non-network option for each of the projects.

1. INTRODUCTION

1.1 PURPOSE

The purpose of this document is to support the Jemena 2021-26 Electricity Distribution Price Review (EDPR) submission by providing justification for proposed capital expenditure during the 2021-26 regulatory period on Jemena's high voltage electricity distribution feeder projects.

1.2 SCOPE

The scope of this document is to provide an assessment of the capacity of the Jemena high voltage electricity distribution feeders to meet forecast customer demand, and where capital expenditure is planned during the 2021-26 regulatory period to address a capacity constraint, present the project justification, options, recommendation, scope and cost within this document.

Jemena high voltage electricity distribution feeders include the overhead and underground lines and associated equipment located downstream of the zone substation bus and upstream of the distribution substation transformers. In the Jemena Electricity Network, high voltage electricity distribution feeders operate at voltages of 22 kV, 11 kV or 6.6 kV. Distribution substation transformer and low voltage network limitations are excluded from this assessment.

A feeder project may include feeder upgrade, reconfiguration, extension or construction of a new feeder. This includes modification or addition as required of associated in-line equipment (e.g. switches, voltage regulators) and secondary systems. This document does not cover projects where the sole driver is a single customer initiated project.

1.3 OBJECTIVES

To meet the requirements of the National Electricity Rules (NER), the Victorian Electricity Distribution Code (VEDC), and public and industry expectations for improved distribution system performance, the following objectives[4] need to be achieved:

- *(1) meet or manage the expected demand for standard control services over that period;*
- *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
- *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
  - *(i) the quality, reliability or security of supply of standard control services; or*
  - *(ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent:*
  - *(iii) maintain the quality, reliability and security of supply of standard control services; and*
  - *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
- *(4) maintain the safety of the distribution system through the supply of standard control services.*

4 National Electricity Rules (NER), clause 6.5.6 (a)

2. DISTRIBUTION FEEDER PLANNING

The process for high voltage electricity distribution feeder planning involves assessing whether feeder capacity is sufficient to meet forecast demand under system normal and single contingency conditions. Where capacity is insufficient to meet demand, network augmentation or non-network alternatives may be required.

Jemena's Customer and System Planning team is responsible for determining feeder ratings, developing annual load forecasts, assessing feeder utilisation and initiating network augmentation projects for the Jemena electricity network to ensure customer demand can be supplied.

In addition, Jemena's Customer and System Planning team is responsible for ensuring quality of supply meets the Electricity Distribution Code requirements. In particular, capacity of a feeder may be constrained due to voltage drop on long feeders.

Each of the components of high voltage electricity distribution feeder planning are summarised below. For more details of the Jemena electricity network planning process and criteria, refer to "JEN PR 0007 JEN Network Augmentation Planning Criteria"[5].

2.1 FEEDER RATINGS

The rating of a feeder is determined by the current carrying capacity of the limiting section of the feeder exit (including feeder circuit breaker) or feeder backbone up to the first load or transfer point. Note that there may also be limitations further along the feeder which are not reflected in these feeder ratings.

Conductor and cable ratings are influenced by the ambient temperature, size and type of material used and design of the installation. Refer to "JEN MA 0010 Jemena Planning Manual"[6] for more details. Maximum safe loading limit is determined based on the conductor and/or cable maximum operating temperature where these assets deteriorate rapidly to an unacceptable level or statutory clearance limit is likely to be infringed when operating above this level.

Jemena has calculated the feeder rating based on the 50POE ambient temperature condition i.e. average ambient temperature of 29.4 degree Celsius. This is a conservative approach as the feeder rating could be much lower during a 10POE maximum demand condition. Based on JEN calculation the feeder rating could be 10-15% lower when the ambient temperature is closer to the 10POE demand condition. This elevates the need to augment the feeders listed under Table 3–1 that Jemena has identified as being heavily loaded during the 2021-26 regulatory period.

For 50% POE feeder ratings (i.e. maximum safe loading limits) for JEN feeders refer to "RP-NCPA-NJO-2019-175 JEN Load Demand Forecast"[7].

2.2 LOAD DEMAND FORECASTING

Load demand forecasting is critical to a network's operation as it is a principal driver of capital expenditure. However uncertainty always surrounds forecasts due to the inherent unpredictability of factors such as ambient temperatures, weather patterns and, in particular, loads. Load growth can vary from year to year and is not uniform

[5] Jemena, *"JEN PR 0007 JEN Network Augmentation Planning Criteria"*, May 2019

[6] Jemena, *"JEN MA 0010 Jemena Planning Manual"*, February 2013

[7] Jemena, *"RP-NCPA-NJO-2019-175 JEN Load Demand Forecast"*, November 2019

across the whole network. It is not unusual to find parts of the network which grow at three or four times the average network growth rate, while other parts of the network could experience no growth at all.

The process for preparing peak demand forecasts calls for two independent sets of forecasts to be prepared annually, spatial level (i.e. bottom-up) forecast and system level (i.e. top-down) forecast. The spatial level forecast is prepared internally by JEN and the system level forecast is prepared by an independent external (macro) economic forecaster (ACIL Allen Consulting).

The spatial forecasts are built up from a feeder level to zone substation level and then to terminal station level, taking into account diversity at each level of aggregation. The forecasts are based on trends identified by looking backwards at historical data and looking forwards at drivers in the future that influence load growth. The forward looking drivers include known future loads, knowledge of local information such as proposed major industrial and commercial developments, predicted housing and industrial lot releases, proposed embedded generation and other items such as economic forecasting, council planning and various Precinct Structure Plans conducted by Metropolitan Planning Authority[8] are also taken into account. Two forecast scenarios are produced; one for summer, and one for winter peak demand conditions, each with a 10% and a 50% probability of exceedance (POE).

The system level forecasts were prepared by an independent external forecaster, ACIL Allen Consulting, using econometric techniques. These system level forecasts include a summer and winter demand forecast at the total network demand for the 10%, 50% and 90% POE levels. The drivers of demand used in the model includes:

- Economic outlook for Victoria and Jemena supply area, as measured by Victorian Gross State Product (GSP) growth rate (%).
- Population growth and customer numbers
- Photovoltaic (PV) generation capacity and battery storage.
- Electricity prices.
- Variations in temperature pattern (weather).
- Electric Vehicles (EV)

In summary, the system level forecast methodology adopted by ACIL Allen Consulting includes:

- regression models were estimated to quantify the relationship between electricity demand and its drivers
- those models were used with projections of the drivers to produce baseline forecasts.
- A post model adjustment was made to the forecasts to account for the impact of ongoing take-up of solar PV systems, battery storage and electric vehicles.. The process was conducted separately for summer and winter to produce independent forecasts of maximum demand in these seasons. For further detail, please refer to ACIL Allen report “Electricity Demand Forecasts”[9].

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8 Refer to link, http://www.planmelbourne.vic.gov.au/Plan-Melbourne, for Plan Melbourne report.

9 ACIL Allen Consulting, *“Electricity Demand Forecasts”*,2019

JEN reconciles its spatial forecasts to the system level forecast at the total network level to produce the final set of maximum demand forecasts. As a result, the JEN internal spatial forecast is equal to the independent external system forecast at the total network level. JEN adopts its internal spatial forecast for planning its network due to the requirement for forecasts at the feeder and zone substations levels. For further detail of the load forecast methodology, refer to “JEN PR 0507 Load Demand Forecast Procedure”[10].

2.3 UTILISATION

Utilisation of any section of the network is the maximum demand on the section as a proportion of the cyclic rating of that section.

Capacity to supply load must be considered both under system normal and single contingency conditions. During a planned or unplanned outage of a feeder, capacity should be available to transfer all load on the affected feeder to adjacent feeders.

It is considered a minimum service level to ensure that feeder utilisation remains below 100% under 10% POE conditions. This is to ensure all customer demand can be supplied under system normal conditions without the need for planned load shedding during times of peak demand to maintain the feeder loading within its maximum safe loading limit. If a feeder were to be loaded beyond its maximum safe loading limit, assets may be damaged therefore reducing asset life. Conductor annealing may cause HV overhead lines to sag and make contact with LV lines or telephone wires causing HV injections resulting in damage to network/customer assets and a safety risk to personnel and the public. Severe or prolonged overloading may cause conductors and cables to fail.

In some cases, network augmentation is economically justifiable for feeders where utilisation is less than 100% due to insufficient transfer capacity under single contingency conditions. In these cases, a probabilistic planning methodology is used to determine the cost-benefit ratio of the proposed network augmentation. This takes into account the cost to customers of expected unserved energy during outage conditions, probability of an outage occurring and the value of customer reliability (VCR). Refer to “JEN PR 0007 JEN Network Augmentation Planning Criteria”[11] for more detail.

Downstream feeder limitations may also restrict the capacity of the feeder under normal or contingency conditions. In this case, the rating of the section will be assessed and the maximum demand on the section will be estimated to determine utilisation. Appendix C shows the JEN network HV feeders that operated above 80% utilisation during summer 2018/19.

2.4 QUALITY OF SUPPLY

Jemena is responsible for maintaining quality of supply within limits specified by chapter 4 of the VEDC and Schedule 5.1 of the NER. In the absence of non-network solutions, feeder augmentation may be required to address the following power quality issues:

- Voltage – voltage fluctuations may occur due to large variations in load or generation on a feeder. In addition, long feeders may experience excessive voltage drop due to the high impedance of the conductors/cables between source and load. Voltage must be maintained within VEDC limits to prevent incorrect operation of and damage to customer equipment. Voltage is estimated using a network modelling software package CymDist and may be measured in the field to confirm. Possible network solutions include feeder reconductoring or installation of a voltage regulator.

10 Jemena, *“JEN PR 0507 Load Demand Forecast Procedure”*,2019

11 Jemena, *“JEN PR 0007 JEN Network Augmentation Planning Criteria”*, May 2019

- Power factor – a feeder may have a poor power factor due to high density of industrial load. Poor power factor causes higher current. Power factor correction may be used to reduce current flowing in a line and to ensure regulatory requirements are met.
- Harmonics – a feeder may have high harmonic content due to type of customer load connected, often due to electronic loads such as computers or inverter connected generation. Electricity supply with high harmonic content may impact the performance and lifespan of customer equipment. Harmonics filters may be installed on a feeder to reduce harmonic content in order to meet regulatory requirements.

2.5 NETWORK AUGMENTATION

Generally the following network augmentation options are available to address a feeder capacity constraint:

- Do nothing – load shedding may be accepted as the most economical solution to address a capacity constraint.
- Construct a new feeder – a new feeder may tie in to one or more existing feeders and enable the feeders to be reconfigured to optimise utilisation. This option requires a spare feeder connection point to be available at the zone substation, or alternatively an existing feeder circuit breaker with sufficient spare capacity to allow for a piggy-back arrangement.
- Reconductor – this option requires replacing sections of overhead conductor or underground cable with higher rated conductors/ cables in order to remove capacity limitations.
- Thermal uprate – this requires altering the stringing of overhead conductors to increase their thermal rating from 50°C to 65°C maximum conductor design temperature and/or pumping bentonite into underground cable conduits to increase the cable rating from the “in duct” rating to the “direct buried” rating.
- Create tie-line and/or reconfigure feeders – creating a tie line between two feeders can increase transfer capacity under emergency conditions or may enable permanent feeder transfers (feeder reconfiguration) to optimise feeder utilisation.
- Install voltage regulator (or alternative technology) – voltage regulators are essentially transformers with tap changers to adjust the voltage along the feeder, so as to compensate for the voltage drop over distance.
- Install capacitors – capacitors may be installed on a feeder to correct the power factor to reduce current flowing in a line due to reactive power and ensure regulatory requirements are met.
- Install harmonics filters – harmonics filters may be installed on a feeder to ensure regulatory requirements are met.

A cost-benefit analysis is undertaken to identify the best option. In most cases, this will be the least cost option which meets the project objectives.

2.6 NON-NETWORK ALTERNATIVES

Non-network alternatives to network augmentation include:

- Embedded generation – a customer owned embedded generator connected at the feeder level and contracted to generate at times of peak demand can offset load demand.

- Demand management or Direct load control – a customer may enter into a contract with Jemena whereby they will reduce their demand by a specified amount or go off-grid upon request. This can reduce feeder loading at times of maximum demand. Direct load control is another form of demand management where the customer enter into a contract with Jemena directly or through a Demand Response service provider which enables Jemena to control certain equipment like pool pumps, air conditioning during peak demand period.
- Energy Storage – a third party proponent may enter into a contract with Jemena to install energy storage units at strategic locations to reduce the network demand. This can be grid connected or behind the meter solutions.
- Voltage reduction – Jemena can reduce voltage at a zone substation level to reduce overall demand. This will require managing risk of undervoltage events using smart meter data in near real time.

From the above list, Jemena has prior experience in performing demand management trials for both residential and commercial customers. From JEN's prior experience, demand management is most effective on feeders that are supplying predominantly commercial and industrial customers. As a general guideline, the cost of demand management may be considered between $60,000 to $100,000 per MW per annum for availability (depending upon the location, automation and response rate) and approximately $3,000 to $5,000 per MWh for dispatch.

Feeder capacity limitations and proposed network augmentation projects for the forward planning period are published annually in the Distribution Annual Planning Report (DAPR). The public is invited to propose non-network alternatives to network augmentations. Detailed analysis will be undertaken at the time of preparing the business case for each of the individual project to identify the feasibility of implementing a non-network solution. In the absence of any proposals for non-network alternatives, the planned network augmentation project will proceed.

There are currently no proposals for non-network alternatives on the proposed feeder projects for the next regulatory period (2021-26). Jemena continues to seek non-network alternatives as per document "JEN PL 0104 Demand Side Engagement Document"[12].

[12] Jemena, *"JEN PL 0104 Demand Side Engagement Document"*, March 2014, available from https://jemena.com.au/about/document-centre/electrcitiy/demand-side-engagement

3. JEMENA ELECTRICITY NETWORK FEEDER UTILISATION

Table 3-1 below lists the feeder utilisation for HV feeders within the Jemena electricity network which are forecast to reach or exceed the maximum safe loading limit under 10% POE demand conditions by summer 2025/26.

Table 3–1: Feeders forecast to reach or exceed 100% utilisation by summer 2025/26 (10% POE forecast)

Feeder	Season	Rating	10% POE Demand Forecast							Comments
			2020	2021	2022	2023	2024	2025	2026	
AW01	Summer	285	273	275	284	293	299	307	315	Proposed project "New feeder – TMA015" – refer section 4.9
	Winter	285	210	212	217	224	227	231	236	
AW06	Summer	305	392	391	395	393	391	391	390	Proposed project "New feeder – TMA015" – refer section 4.9
	Winter	305	220	219	219	218	215	214	213	
AW07	Summer	305	372	367	369	368	371	377	381	Proposed project "New feeder – TMA015" – refer section 4.9
	Winter	305	221	218	217	217	217	219	220	
BD08	Summer	305	243	246	247	244	243	243	242	Proposed project " BD08, BD13 & ST34 Capacity Constraint – refer section 4.16
	Winter	305	242	245	245	242	238	237	235	
BD13	Summer	315	235	224	248	256	259	263	266	Proposed project " BD08, BD13 & ST34 Capacity Constraint – refer section 4.16
	Winter	315	252	240	264	273	273	275	278	
CS02	Summer	355	323	324	325	320	320	320	321	Proposed project "Augment feeder CS05"– refer section 4.14
	Winter	355	200	201	199	197	195	194	193	
CS05	Summer	325	264	261	273	285	296	309	322	Proposed project "Augment feeder CS05"– refer section 4.14
	Winter	325	183	182	188	197	202	209	217	
COO11	Summer	310	320	356	404	439	476	520	567	There is a project proposed in 2020 that is about to be committed
	Winter	310	264	294	330	359	385	418	454	
COO22	Summer	320	227	235	252	264	273	284	294	Proposed project "COO22 and ST32 Capacity Constraint"– refer to section 4.13
	Winter	320	198	205	217	229	234	241	249	
EP9	Summer	345	273	297	321	334	332	331	330	Addressed through proposed Preston Conversion Program
	Winter	345	299	325	348	363	357	354	352	
EP34	Summer	285	302	297	294	288	286	285	284	Addressed through proposed Preston Conversion Program
	Winter	285	230	226	222	217	214	212	210	
ES15	Summer	305	262	269	284	291	296	303	310	Proposed project "Reconfigure feeder ES23" refer section 4.7
	Winter	305	134	138	144	148	149	152	155	
ES22	Summer	375	399	394	391	384	382	383	382	Proposed project "Reconfigure feeder ES23" – refer section 4.7
	Winter	375	367	362	356	350	345	343	342	
FE06	Summer	360	301	318	369	428	468	514	564	

Feeder	Season	Rating	10% POE Demand Forecast							Comments
			2020	2021	2022	2023	2024	2025	2026	
	Winter	360	248	262	301	350	379	413	452	Proposed project "Augment feeder FE6 – refer section 4.2
FF87	Summer	285	186	204	226	249	265	284	304	Project proposed as part of CIC connection
	Winter	285	175	192	211	232	245	261	278	
FF95	Summer	285	286	373	542	714	853	1040	1238	Project proposed as part of CIC connection
	Winter	285	213	278	400	528	625	756	897	
FT21	Summer	250	230	238	246	249	252	257	261	Proposed project "New feeder – FT12" – refer section 4.4
	Winter	250	193	199	203	207	207	210	213	
FT31	Summer	305	232	229	242	256	270	286	303	Proposed project "New feeder – FT12" – refer section 4.4
	Winter	305	229	226	237	252	264	278	293	
HB15	Summer	375	341	344	363	381	398	417	436	Proposed project "New feeder – HB21" – refer section 4.15
	Winter	375	243	245	256	269	278	289	301	
NS11	Summer	375	304	324	352	365	378	393	408	Proposed project "Reconfigure feeder ES23" – refer section 4.7
	Winter	375	241	259	280	292	300	311	322	
NS12	Summer	285	195	197	207	215	223	304	412	Project proposed as part of CIC connection
	Winter	285	100	101	105	109	112	152	205	
NS15	Summer	285	253	252	253	249	249	251	252	Proposed project "Augment – NS15" – refer to section 4.6
	Winter	285	162	162	161	159	157	157	157	
NS18	Summer	305	192	226	279	332	365	403	445	Proposed project "Augment – NS18" – refer to section 4.7
	Winter	305	144	168	206	246	267	294	323	
NH02	Summer	375	389	390	391	383	381	381	381	Load due to traction station – no project proposed
	Winter	375	305	306	304	298	294	292	291	
NH16	Summer	235	219	221	220	217	222	229	236	Adjacent feeders have transfer capacity – no project proposed
	Winter	235	144	145	143	142	144	147	151	
NT11	Summer	285	270	274	277	274	272	272	272	Proposed project "Augment Feeder NT11" – refer to section 4.3
	Winter	285	214	218	217	215	212	211	210	
NT15	Summer	295	215	239	266	276	291	308	326	Proposed project "Augment Feeder NT11" – refer to section 4.3
	Winter	295	190	211	232	241	252	265	280	
NT17	Summer	285	312	323	337	340	340	343	344	Load due to traction station – no project proposed
	Winter	285	265	274	284	287	284	284	285	
ST32	Summer	325	328	368	410	442	464	489	514	Proposed project "Augment feeder KLO21 – refer section 4.12
	Winter	325	224	251	277	299	311	325	341	

Feeder	Season	Rating	10% POE Demand Forecast							Comments
			2020	2021	2022	2023	2024	2025	2026	
ST33	Summer	315	318	326	334	331	332	335	338	Proposed project “Augment feeder KLO21 – refer section 4.12
	Winter	315	167	171	173	172	171	172	173	
ST34	Summer	375	255	252	274	300	322	348	376	Proposed project “ BD08, BD13 & ST34 Capacity Constraint – refer section 4.16
	Winter	375	244	241	260	285	303	325	349	
YVE-21	Summer	285	240	294	367	440	526	622	734	Proposed project “Reconfigure feeder YVE11”–refer section 4.1
	Winter	285	209	255	316	379	449	526	617	
YVE-22	Summer	205	200	208	213	209	208	209	209	Proposed project “Reconfigure feeder YVE11”–refer section 4.1
	Winter	205	171	178	180	177	175	175	174	

Please refer to “RP-NCPA-NJO-2019-175 JEN Load Demand Forecast”[13] for complete feeder forecasts.

Feeder utilisation above is based upon the rating of the feeder exit. In some cases feeder projects may be required due to downstream limitations.

Jemena has calculated the feeder rating based on the 50POE ambient temperature condition i.e. average ambient temperature of 29.4 degree Celsius. This is a conservative approach as the feeder rating could be much lower during a 10POE maximum demand condition. Based on JEN calculation the feeder rating could be 10-15% lower when the ambient temperature increases closer to the 10POE demand condition. This elevates the need to address the loading constraint on the feeders identified in Table 3–1. A detailed assessment will be conducted under the 10POE demand condition using 10POE rating as well as factoring the 50POE demand condition as it gets closer to the proposed augmentation date to confirm the exact optimal timing of the preferred solution.

13 Jemena, *“RP-NCPA-NJO-2019-175 JEN Load Demand Forecast”*, November 2019

4. PROJECT JUSTIFICATION

In order to maintain a safe and reliable electricity supply to customers, Jemena proposes a total capital expenditure of $32.8 million (real $2019 with overheads)[17] across 16 projects during the 2021-26 regulatory period to address high voltage electricity distribution feeder capacity constraints.

Table 4–1 summarises the proposed projects, completion date and estimated expenditure.

As these feeders are projected to reach or exceed their safe loading limit under system normal conditions, a deterministic planning method has been applied, which is consistent with Jemena's network augmentation criteria[14], and a cost comparison (rather than a cost-benefit analysis) of the different options have been used in the analysis. Sections 4.1 to 4.16 below provides a summary of these cost comparison of the different options and justification for each project.

Table 4–1: Proposed projects, completion date and expenditure

Project Title	Completion Date	2021-2026 Expenditure (Real $2019)	Reference
Reconfigure Feeder YVE11	2021	$2.64M[15]	Section 4.1
Augment Feeder FE06	2023	$2.82M	Section 4.2
Augment Feeder NT11	2022	$3.00M	Section 4.3
New Feeder FT12	2025	$2.38M[17]	Section 4.4
Augment Feeder NS18	2023	$1.29M	Section 4.5
Augment Feeder NS15	2026	$0.87M[16]	Section 4.6
Reconfigure Feeder ES23	2021	$2.61M[17]	Section 4.7
Augment steel section of Feeder SBY24	2026	$1.61M[17]	Section 4.8
New Feeder TMA15	2024	$2.32M	Section 4.9
Install Regulator SBY13	2025	$0.35M[17]	Section 4.10
Reconfigure Feeder SBY24	2024	$1.43M	Section 4.11
Reconfigure Feeder KLO21	2022	$3.94M	Section 4.12
COO22 and ST32 Capacity Constraint	2024	$3.65M	Section 4.13
Augment Feeder CS05	2021	$0.28M[17]	Section 4.14
New Feeder HB21	2023	$3.03M	Section 4.15
BD08, BD13 & ST34 Capacity Constraint	2024	$0.58M	Section 4.16
TOTAL		**$32.8M[17]**	

14 Refer to Jemena, *"JEN PR 0007 JEN Network Augmentation Planning Criteria"*, for Jemena's augmentation criteria.

15 The estimated project cost includes expenditure in FY20.

16 The estimated project cost includes expenditure in FY27 due to project completion is proposed by November 2026.

17 The total capex expenditure includes $0.3M in FY20 for six projects, and $0.9M in FY27 for two projects that are proposed to be completed by November 2026.

4.1 RECONFIGURE FEEDER YVE11

4.1.1 BACKGROUND

Feeder YVE21 and YVE22 is forecast to reach 109% and 101% utilisation during summer 2021/22 under system normal condition (10POE demand condition). The feeder supplies a mixture of both commercial and residential customers. The proposal by Footscray City Council to develop Josephs Rd into high rise residential/commercial development has resulted in the increase in demand on the feeders. The Josephs Rd precinct development is forecasted to add about 12-14 MVA of load on to the JEN network. Based on the current forecast the feeder will be operating above its rating under system normal condition by summer 2021/22. Under this scenario, approximately 1.0 MVA of load will have to be shed under system normal condition.

Besides this, YVE21 has limited transfer capability during single contingency condition. YVE21 has ties to FE06, FE02, FE09 and YVE14 which are forecast to be loaded to 103%[18], 51%, 57% and 84% respectively (10 POE demand condition) by summer 2021/22. Due to the existing network configuration, YVE14 and FE09 transfers are mutually exclusive, i.e. only one transfer point may be utilised at a time. In addition, if these transfer points are used, no load can remain on YVE21. Under single contingency conditions during summer 2021/22, approximately 6.5 MVA of customer load will be shed.

4.1.2 OPTIONS

Option 1: Do nothing – Under this option, approximately 1.0 MVA of customer load will be shed under system normal condition and approximately 6.5 MVA of customer load needs to be shed during single contingency conditions (10POE demand condition) during summer 2021/22.

Option 2: Reconfigure YVE11 ($2.64M) – Under this option the existing YVE11 feeder will be reconfigured to support the development around Josephs Rd. The existing load on YVE11 will be transferred on to YVE24 feeder. This project involves installing approximately 900m of new underground cables, reconductoring approximately 800m of overhead lines, installing approximately 600m of new overhead conductors and thermally uprating approximately 300m of overhead lines.

Option 3: New feeder FE11 ($2.46M) – This option looks at running a new feeder from Footscray East (FE) Zone Substation. The substation has spare feeder CB's available. This project involves installing approximately 1000m of new underground cables, reconductoring approximately 800m of overhead lines, installing approximately 1000m of new overhead conductors and thermally uprating approximately 500m of overhead lines. The FE zone substation currently has energy at risk under N-1 condition. Adding more load on to the substation will substantially increase the risk at the zone substation which could result in a more expensive zone substation augmentation project. Hence, this option is not the preferred option.

Option 4: Uprate YVE21 ($2.05M) – This option looks at thermally uprating the existing YVE21 feeder from 270A to 445A to supply the increased load. This option requires replacing approximately 1.4km of underground cable with new 300mm^2 Al XLPE cable and thermally upgrade 1.2km of overhead conductors along Whitehall St. The option will provide temporary capacity for YVE21 feeder to meet the expected increase in demand. However, transfer capability during contingency (feeder fault on YVE21) will still be an issue. This option does not meet the full objective of this project, hence is not the preferred option.

Option 5: Energy Storage ($18.6M, 10 year asset life) – This option looks at installing 14MWh (4.5MVA) battery system on feeder YVE21 for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

[18] Loading of FE-006 feeder is addressed as part of a different project. See details in Section 4.2

Option 6: Demand management (2 year program) and Reconfigure YVE11 ($3.91M) – This option looks at engagement with commercial and industrial customers on feeder YVE21 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder YVE21 has potential demand reduction on commercial and industrial demand for 2.4MVA.

Option 7: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on YVE21 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2020/21.

4.1.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–2.

Table 4–2: Summary of Present Value Analysis for Reconfigure Feeder YVE11

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$117.86M	6
2	$2.64M	$2.49M	1
3	$2.46M	$2.32M	3
4	$2.05M	$1.93M	4
5	$18.60M	$30.68M	5
6	$3.91M	$3.37M	2

4.1.4 RECOMMENDATION

The recommended option is to reconfigure YVE11 (Option 2) to supply the growing load at Josephs Rd precinct (Option 2) by November 2021, with a total capital expenditure of $2.64M (real 2019). A new feeder from FE zone substation (Option 3) will increase the load at risk at the zone substation, which will result in an expensive zone substation augmentation projects. Option 4 was discarded as it does not meet the full objective of this project.

4.2 AUGMENT FEEDER FE06

4.2.1 BACKGROUND

Jemena FE06 feeder from Footscray East (FE) zone substation is forecast to reach 119% utilisation during summer 2023/24 under system normal condition (10 POE demand condition). Under this scenario, approximately 2.6 MVA of load will have to be shed under system normal condition. The feeder currently supplies approximately

2,200 customers in and around the growing Footscray area. The increase in load on the feeder is mainly driven by the surge in high rise residential development around the Footscray region.

Besides this FE06 has limited transfer capability during single contingency condition. FE06 has ties to FE08,FE09, FE05, FE02, BY12 and YVE15 which are forecasted to be loaded to 78%, 76%,94%,52%,23%[19], and 60% in summer 2023/24. Feeder FE05 and FE02 has got ties at the start of the feeder, hence only one tie can be utilised at a time. Besides that FE06 has got a weak tie to lightly loaded BY12 feeder, limiting the full transfer capability during emergency situation. Based on this, under a single contingency conditions during summer 2023/24, approximately 3.3 MVA of customer load will be shed.

4.2.2 OPTIONS

Option 1: Do nothing – This option of doing nothing would mean there is a risk of damaging existing assets and extended interruptions of supply to customers during planned and unplanned outages. Under the 10POE maximum demand condition, approximately 2.6 MVA of customer load will be shed under system normal condition and approximately 3.3 MVA of customer load needs to be shed during single contingency conditions during summer 2023/24.

Option 2: Reconfigure FE06 ($2.82M) – This option involves installing approximately 1200m of new 3C 300mm2 Al XLPE cable to uprate the feeder backbone. The proposed work will also create a new tie between FW08 and FE06 by extending approximately 500m of HV conductors and reconducting approximately 400m of overhead conductor with Jemena standard 19/3.25AAC conductors.

Option 3: New feeder FE11 ($3.46M) – This option looks at running a new feeder from Footscray East zone substation. The substation has spare feeder CB available. The project scope involves running approximately 1900m of new underground cable and reconducting approximately 400m of overhead conductor with Jemena standard 19/3.25AAC conductors. The new feeder will take load away from FE06 feeder and will provide an additional transfer point during contingency condition.

Option 4: Energy Storage ($4.52M, 10 year asset life) – This option looks at installing 1MWh (10MVA) battery system on at FE06 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and Reconfigure FE06 ($3.33M) – This option looks at engagement with commercial and industrial customers on feeder FE06 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder FE06 has potential demand reduction on commercial and industrial demand for 3.1MVA.

Option 6: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on FE06 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2022/23.

4.2.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand

19 Maximum transfer available at this tie point is 100A due to weak link between BY-012 and FE-006

management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–3.

Table 4–3: Summary of Present Value Analysis for Reconfigure FE06

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$9.18M	5
2	$2.82M	$2.66M	1
3	$3.46M	$3.26M	2
4	$4.52M	$7.46M	4
5	$3.33M	$2.82M	3

4.2.4 RECOMMENDATION

The recommended option is to reconfigure FE06 (Option 2) by end of November 2023, with a total capital expenditure of $2.82M (real $2019). It is the least cost option which optimises the feeder utilisation that addresses the capacity constraint and provides reliable and adequate supply to customers in the area.

4.3 AUGMENT FEEDER NT11

4.3.1 BACKGROUND

Jemena owned Newport (NT) zone substation currently has seven HV feeders servicing approximately 16,000 customers in the Newport area. The feeders are servicing a mixture of residential and large commercial customers such as Tenix Dockyard, Mobil Co, Metro (MTM). NT feeders have limited transfer capacity leaving significant load at risk during single contingency condition.

Besides this, NT15 is forecasted to reach its N-rating by summer 2026 under 10 POE forecast condition. NT17 is already above its N-rating and is currently managed by temporary feeder transfers. Based on the current JEN demand forecast NT15 and NT17 will be loaded to 90% and 118% by 2022/23.

The objective of this project is to relive feeders that are projected to go beyond its N-rating and to better configure the load between NT feeders to have enough transfer capability during contingency condition.

4.3.2 OPTIONS

<u>Option 1: Do nothing</u> – This option of doing nothing would mean there is a risk of damaging existing assets and extended interruptions of supply to customers during planned and unplanned outages. Under the 10POE maximum demand condition approximately 1.7 MVA load will be under risk during system normal condition.

<u>Option 2: Uprate feeder NT03 and NT15 ($3.40M)</u> – This option involves replacing approximately 1000m of feeder exit cable for NT15 and approximately 500m of feeder exit cable for NT03. The project scope also involves reconductoring approximately 1500m of overhead conductor on NT15 and approximately 1500m of overhead conductor on NT03 to increase the feeder rating from 285A to 375A. The project will address the overloading on the feeders.

Option 3: New feeder NT02 ($3.00M) – This option looks at running a new feeder from Newport (NT) zone substation. The substation has spare feeder CB available. The project scope involves running approximately 900m of new underground cable and approximately 2500m of new 19/3.25AAC overhead conductor to establish the new feeder. On completion of the new feeder, load will be reconfigured between NT04,NT11,NT15 and NT03 to balance the loading on the NT feeders and to provide sufficient back up during single contingency.

Option 4: Energy Storage ($1.96M, 10 year asset life) – This option looks at installing 1MWh (2MVA) battery system on at NT11 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and New feeder NT02 ($3.42M) – This option looks at engagement with commercial and industrial customers on feeder NT11 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder NT11 has potential demand reduction on commercial and industrial demand for 3.5 MVA.

Option 6: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on feeder supplied from NT zone substation. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2021/22.

4.3.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–4.

Table 4–4: Summary of Present Value Analysis for Augment Feeder NT11

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$22.88M	5
2	$3.40M	$3.20M	3
3	$3.00M	$2.82M	1
4	$1.96M	$3.23M	4
5	$3.42M	$2.89M	2

4.3.4 RECOMMENDATION

It is recommended to install a new feeder from NT (NT02 - Option 3) by end of November 2022, with a total capital expenditure of $3.00M (real $2019). It is the least cost option which addresses the capacity constraint on feeders supplied from NT zone substation and provides reliable and adequate supply to customers in the area.

4.4 NEW FEEDER FT12

4.4.1 BACKGROUND

Jemena owned Flemington (FT) zone substation is one of the four zone substations: Essendon Zone Substation (ES), Flemington Zone Substation (FT), North Essendon Zone Substation (NS) and Pascoe Vale Zone Substation (PV), which form central 11kV network that is electrically isolated from JEN's surrounding networks, which operate at 6.6 kV and 22 kV.

11kV Feeders FT11, FT26, FT31 and FT32 are forecasted to reach 93%, 73%, 99%, 74% utilisation respectively under 10POE demand conditions by summer 2025/2026. The feeders FT11 and FT26 are servicing a mixture of residential and large commercial customers such as Melbourne and Metropolitan Tramways Board (MMTB) and Metro Trains (MTM).

Based on the current JEN forecast FT31 is forecast to almost reach its N-rating by 2025/26. Besides that, there is also limited transfer capacity between the 11kV HV feeders. Based on this, under a single contingency conditions during summer 2025/26, approximately 5.5 MVA of customer load will be shed.

4.4.2 OPTIONS

Option 1: Do nothing – Under this option, approximately 0.2 MVA of customer load will be shed under system normal condition and approximately 5.5 MVA of customer load needs to be shed during single contingency conditions (10POE) during summer 2025/26.

Option 2: Reconfigure FT32 ($1.36M) – This option involves uprating feeder FT32 by replacing approximately 700m of existing underground cable and reconductoring of approximately 480m of overhead conductor to allow load transfer from FT31 to FT26 and FT22.

Option 3: New Feeder FT12 ($2.38M) – This option involves running a new feeder from Flemington (FT) zone substation. The substation has spare CB available. The proposed works under this option involves approximately 1480 metres of new underground cable to establish the new feeder and approximately 550 metres of overhead conductor reconductoring as well as replacement of 200 metres of underground cable. On completion of the new feeder, the load will be reconfigured between the new feeder, FT11 and FT31 and the new feeder will also provide support / transfer capacity to the adjacent feeder FT24, FT26 and FT22.

Option 4: Energy Storage ($15.86M, 10 year asset life) – This option looks at installing 21.5MWh (5.5MVA) battery system on at FT11 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and New feeder FT12 ($3.20M) – This option looks at engagement with commercial and industrial customers on feeder FT11 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option.. Feeder FT11 has potential demand reduction on commercial and industrial demand for 0.3 MVA.

Option 6: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on feeder supplied from FT zone substation. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2024/25.

4.4.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–5.

Table 4–5: Summary of Present Value Analysis for New Feeder FT12

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$13.10M	4
2	$1.36M	$1.28M	3
3	$2.38M	$2.24M	1
4	$15.86M	$26.16M	5
5	$3.20M	$2.74M	2

4.4.4 RECOMMENDATION

It is recommended to install a new feeder from FT (FT12 - Option 3) by end of November 2021, with a total capital expenditure of $2.38M (real $2019). This option is not the least cost option, however it is preferred over Option 2 as Option 2 only resolve a portion of load at risk due to feeder transfer limitation.

4.5 AUGMENT FEEDER NS18

4.5.1 BACKGROUND

Jemena owned North Essendon (NS) zone substation is one of the four zone substations: Essendon Zone Substation (ES), Flemington Zone Substation (FT), North Essendon Zone Substation (NS) and Pascoe Vale Zone Substation (PV), which form central 11kV network that is electrically isolated from JEN's surrounding networks, which operate at 6.6 kV and 22 kV.

Feeders NS-018 is forecasted to reach 109% utilisation above its N-rating under 10POE demand conditions by summer 2023/24.

The objective of this project is to relieve overloading on feeder NS18 which is servicing a mixture of residential and commercial customers in Moonee Ponds growth area.

4.5.2 OPTIONS

<u>Option 1: Do nothing</u> – Under this option, approximately 0.5 MVA of customer load will be shed under system normal condition and approximately 5.6 MVA of customer load needs to be shed during single contingency conditions (10POE demand condition) during summer 2023/24.

<u>Option 2: Augment NS18 ($1.29M)</u> – This option involves thermal uprate on approximately 280 metres of existing overhead conductor, installation of approximately 280 metres of overhead conductor and installation of approximately 230m of underground cable. The load will be reconfigured between NS07, NS18 and NS11 (new feeder that will be completed under customer initiated capex project).

Option 3: New Feeder NS06 ($2.97M) – This option involves running a new feeder from North Essendon (NS) zone substation. No spare CB is available to run the new feeder and new CB and associated protection relay inside the zone substation the needs to be installed as part of the option. The proposed works under this option involves approximately 3000 metres of underground cable to form the new feeder. On the completion of the new feeder, the load will be reconfigured between the new feeder, NS15 and NS18.

Option 4: Energy Storage ($13.0M, 10 year asset life) – This option looks at installing 17MWh (5MVA) battery system on at NS18 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and Augment NS18 ($1.98M) – This option looks at engagement with commercial and industrial customers on feeder NS18 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder NS18 has potential demand reduction on commercial and industrial demand for 2.5 MVA.

Option 6: Customer initiated non-network solution - Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2022/23.

4.5.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–6.

Table 4–6: Summary of Present Value Analysis for Augment NS-018

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$10.39M	4
2	$1.29M	$1.21M	1
3	$2.97M	$2.80M	3
4	$13.0M	$21.44M	5
5	$1.98M	$1.71M	2

4.5.4 RECOMMENDATION

It is recommended to augment feeder NS-018 (Option 2) by end of November 2022, with a total capital expenditure of $1.29M (real $2019). It is the least cost option which optimises the feeder utilisation that addresses the capacity constraint and provides reliable and adequate supply to customers in the area.

4.6 AUGMENT FEEDER NS15

4.6.1 BACKGROUND

Jemena owned North Essendon (NS) zone substation is one of the four zone substations: Essendon Zone Substation (ES), Flemington Zone Substation (FT), North Essendon Zone Substation (NS) and Pascoe Vale Zone Substation (PV), which form central 11kV network that is electrically isolated from JEN's surrounding networks, which operate at 6.6 kV and 22 kV.

Feeders NS15 is forecasted to reach 88% utilisation respectively under 10POE demand conditions by summer 2026/2027. Besides this NS15 has limited transfer capability during single contingency condition. NS15 has ties to NS18 and NS12, which are forecasted to be loaded to 146% and 145%. Based on this, under a single contingency conditions during summer 2026/27, approximately 4.8 MVA of customer load will be shed.

This objective of this project is to improve feeder connection and operational flexibility on adjacent feeders that is currently and/or will supply Moonee Ponds growth area (feeder NS18) and Moonee Valley Racecourse redevelopment (feeder NS09).

4.6.2 OPTIONS

Option 1: Do nothing – Under this option, approximately 4.8 MVA of customer load needs to be shed during single contingency conditions (10POE demand condition) during summer 2026/27.

Option 2: Augment NS-15 ($0.87M) – This option involves replacement of feeder exit underground cable of approximately 150 metres outside the zone substation and reconductoring approximately 1400 metres of existing overhead conductor.

Option 3: New NS Feeder ($3.26M) – This option involves running a new feeder from North Essendon (NS) zone substation. No spare CB is available to run the new feeder and new CB and associated protection relay inside the zone substation the needs to be installed as part of the option. The proposed works under this option involves approximately 3000 metres of underground cable to form the new feeder. On the completion of the new feeder, the load will be reconfigured between the new feeder, NS15 and NS18.

Option 4: Energy Storage ($17.94M, 10 year asset life) – This option looks at installing 17.5MWh (5MVA) battery system on at NS15 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and Augment NS15 ($1.59M) – This option looks at engagement with commercial and industrial customers on feeder NS15 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option.. Feeder NS15 has potential demand reduction on commercial and industrial demand for 1.5 MVA.

Option 6: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on Feeder NS-015 or neighbouring feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2025/26.

4.6.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–7.

Table 4–7: Summary of Present Value Analysis for Augment NS-015

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$10.69M	4
2	$0.87M	$0.82M	1
3	$3.26M	$3.07M	3
4	$17.94M	$29.59M	5
5	$1.59M	$1.38M	2

4.6.4 RECOMMENDATION

It is recommended to augment feeder NS15 (Option 2) by end of November 2026, with a total capital expenditure of $0.87M (real $2019). It is the least cost option which optimises the feeder utilisation that addresses the capacity constraint and provides reliable and adequate supply to customers in the area.

4.7 RECONFIGURE FEEDER ES23

4.7.1 BACKGROUND

Jemena owned Essendon (ES) zone substation is one of the four zone substations: Essendon Zone Substation (ES), Flemington Zone Substation (FT), North Essendon Zone Substation (NS) and Pascoe Vale Zone Substation (PV), which form central 11kV network that is electrically isolated from JEN's surrounding networks, which operate at 6.6 kV and 22 kV.

ES22 is projected to be heavily loaded above its N rating (121% utilisation) by summer 2019/20. ES15 and NS11 are projected to be heavily loaded in summer 2024/25 (102% and 109% utilisation respectively). The load at risk on ES22 is currently being managed via temporary transfer under summer preparedness program.

In addition to the above mentioned 11kV feeders operating above their ratings and the expected residential growth in the area of Essendon and Moonee Ponds suburbs, the 11kV feeders are currently have limited load transfer capability under emergency conditions. There is also a capacity constraint on existing sub-transmission line BTS-NS under network contingency events (N-1), which will be addressed under separate network initiated project. Therefore, permanent transfer to NS feeders is not considered as part of the option assessment.

If the recommended project is not implemented, an outage of any one of these feeders would result in supply interruptions of up to 6 MVA in summer 2021/22 until the feeder damage is repaired and the feeder restored to service

4.7.2 OPTIONS

Option 1: Do nothing – Under this option, approximately 1.2 MVA of customer load will be shed under system normal condition and approximately 6.0 MVA of customer load needs to be shed during single contingency conditions (10POE demand condition) during summer 2021/2022.

Option 2: Reconfigure ES23 ($2.61M) – This option involves reconductoring approximately 900 metres of existing ES22 feeder, reconfigure existing feeder ES23 by installation of approximately 1300 metres of underground cables, 780 metres of new overhead conductor, reconductoring of approximately 160 metres and thermal uprate of approximately 420 metres of existing overhead conductor. This option will also create a feeder tie between,ES15,ES22,ES24 and NS11 feeders by extending approximately 780 metres of overhead conductor. As part of the feeder ES23 extension / reconfiguration, this option also will reconfigure the load between ES23, ES15, ES22, ES24 and NS11 feeders.

Option 3: New ES Feeder ($2.85M) – This option involves approximately 2000 metres of underground cable to form the new feeder, thermal uprate approximately 200 metres of existing overhead conductor. This option will also create a feeder tie and reconfigure the load between the new feeder, ES15, ES22 and NS11 feeder.

Option 4: Energy Storage ($13.2M, 10 year asset life) – This option looks at installing 17.5MWh (5MVA) battery system on at ES15 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and Augment ES15 ($3.33M) – This option looks at engagement with commercial and industrial customers on feeder ES-022 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder ES-015 has potential demand reduction on commercial and industrial demand for 1.2 MVA.

Option 6: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on Feeder ES-022 or neighbouring feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2020/21.

4.7.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–8.

Table 4–8 Summary of Present Value Analysis for Reconfigure Feeder Project ES-23

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$10.84M	4
2	$2.61M	$2.46M	1
3	$2.85M	$2.68M	2

4	$13.2M	$21.77M	5
5	$3.31M	$2.83M	3

4.7.4 RECOMMENDATION

It is recommended to reconfigure the feeder ES-023 (Option 2) by end of November 2021, with a total capital expenditure of $2.61M (real $2019). It is the least cost option which optimises the feeder utilisation that addresses the capacity constraint and provides reliable and adequate supply to customers in the area.

4.8 AUGMENT STEEL SECTION OF FEEDER SBY24

4.8.1 BACKGROUND

A spur from 22kV feeder SBY24[20] supplies the area around Lancefield Road, Clarkefield and west end of Konagaderra Rd . Approximately 12km of this spur is only 2 wire (single phase) HV which is made of St (Sc Gz) 3/2.72 conductor. With the new ongoing developments in the area this 2 wire HV section is forecast to be overloaded in summer 2026. JEN has received 3 phase supply enquiries around Clarkefield area which is not available in 'as is' network condition. In addition, this spur does not have any tie with any other feeder such that, if there is a fault the customers in the area will be susceptible for long outages.

Another spur in the same feeder SBY24 supplies the area around the Sunbury Rd/ Wildwood Rd and east end of Konagaderra Rd. This is single phase (2 wire) overhead HV and is constructed with conductor St (Sc Gz) 3/2.72 and is approximately 17km long. Although it has a tie at far end with feeder COO11 at Konagaderra Rd corner of Deep Creek Redgum, there is very limited load transfer capability to COO11 during both planned and unplanned network outages because of its increase load forecast.

4.8.2 OPTIONS

Option 1: Do nothing – Under this option, no 3-phase supply can be supplied to customers if required. Also approximately 1MVA would be shed should an HV overhead conductor failure occur.

Option 2: Augment steel section ($1.61M) – This option will augment approximately 12km steel section of HV along Lancefield road by replacing the existing two wire steel conductor with three phase HV using 19/3.25 AAC and creates a HV tie between two spurs. Following the augmentation 3-phase supply will be available to the customers. Also if a HV conductor failure occurs, the single phase substations can be supplied from remaining two phases instead of extended interruption of supply.

Option 3: Energy Storage ($2.95M, 10 year asset life) – This option looks at installing 3.5MWh (1MVA) battery system on at SBY-024 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 4: Demand management (2 year program) and Augment steel section ($2.03M) – This option looks at engagement with commercial and industrial customers on feeder SBY24 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option.. Feeder SBY-024 has potential demand reduction on commercial and industrial demand for 0.4 MVA.

Option 5: Customer initiated non-network solution – There are currently no proponents for demand management or embedded generation on SBY24 or adjoining feeders. Jemena will continue to accept non-network solution

[20] The feeder name was previously SBY14. After SBY redevelopment project in 2018 it has been changed to SBY24.

from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2024/25.

4.8.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–9.

Table 4–9: Summary of Present Value Analysis for Augment steel section of feeder SBY32

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$2.26M	3
2	$1.61M	$1.52M	1
3	$2.95M	$2.78M	4
4	$2.03M	$1.73M	2

Based on Table 4–9, Option 2 is the preferred option as it has the least present value of future costs. Option 4 has similar present value of future cost but it is not preferred due to the potential commercial and industrial demand is inadequate to meet the objective of the project.

4.8.4 RECOMMENDATION

It is recommended to augment steel section of SBY24 (Option 2) by end November 2026, with a total capital expenditure of $1.61M (real 2019). This is the least cost option that alleviates the network constraints and provides reliable and adequate supply to customers in the Sunbury rural area.

4.9 NEW FEEDER TMA15

4.9.1 BACKGROUND

Currently two adjacent feeders AW06 and AW07 supply approximately 5,200 and 5,000 customers respectively. By summer 2024/25, feeders AW06 and AW07 are forecast to be 128% and 122% of their ratings respectively under 10% POE conditions.

AW08 has some spare capacity to accommodate the load partially from highly loaded feeders AW06 and AW07 but, existing ties between these three feeders are not strong to facilitate load transfer. Hence, if there is any unplanned outage on either of two feeders AW06 or AW07, a large number of customers are susceptible to loss of supply because load shedding is required to maintain feeder load within their limits.

4.9.2 OPTIONS

Option 1: Do nothing – Under this option, up to 4.3 MVA of load representing approximately 1600 customers would be shed under single contingency conditions (10% POE demand condition).

Option 2: Install new feeder from TMA and reconfigure feeders TMA11, AW06, AW07 and AW08 ($2.32M) – This option would involve installing approximately 1.6km of new 300mm^2 Al cables, thermal uprate of approximately 1.4km of HV overhead conductors, reconductor of approximately 650m of 65SR conductor with 19/3.25 AAC and installing 3 ACRs. On completion of this feeder, load will be reconfigured between TMA15,TMA11,AW06 and AW-07 to balance the loading on the TMA and AW feeders and to provide sufficient back up during single contingency. This option also provides the transfer capacity for feeders BY11 and BY14. This will support to relief BY zone substation during peak summer period which is already running above N-1 capacity.

Option 3: Energy Storage ($11.84M, 10 year asset life) – This option looks at installing 16MWh (4.5MVA) battery system on at TMA11 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 4: Demand management (2 year program) and Install new feeder from TMA and reconfigure feeders TMA11, AW06, AW07 and AW08 ($2.97M) – This option looks at engagement with commercial and industrial customers on feeder YVE21 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder TMA11 has potential demand reduction on commercial and industrial demand for 1.9 MVA.

Option 5: Customer initiated non-network solution – There are currently no proponents for demand management or embedded generation on AW06, AW07 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2023/24.

4.9.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–10.

Table 4–10: Summary of Present Value Analysis for New Feeder TMA-015

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$9.93M	3
2	$2.32M	$2.18M	1
3	$11.84M	$19.53M	4
4	$2.97M	$2.53M	2

4.9.4 RECOMMENDATION

It is recommended to install new feeder from TMA and reconfigure feeders TMA-11, AW-06, AW-07 and AW-08 by November 2024, with a total capital expenditure of $2.32M (real 2019). Following implementation of this option the load and the customer numbers will be evenly shared between these feeders. In addition there will be sufficient transfer capacity under single contingency conditions thereby reducing the overall load at risk during network outage conditions.

4.10 INSTALL REGULATOR SBY13

4.10.1 BACKGROUND

Feeder SBY13[21] supplies approximately 3000 customers northwest of Sunbury zone substation (SBY). It extends up to the Powercor supply area boundary in Gisborne. The backbone section of the feeder is approximately 15 km long and the spurs are up to 7 km long. Most of the feeder backbone is made up of ACSR/AZ 6/1/3.0 7/1.60 conductor and almost all the rural spurs are 2 wires and made from 3/2.75 St (Sc Gz) conductor. With the ongoing developments in the area there is significant load growth around the start of the feeder therefore the voltage level toward the feeder end is likely to be below the Electricity Distribution Code requirement.

4.10.2 OPTIONS

<u>Option 1: Do nothing</u> – Under this option, load shed may happen to the customers on SBY to maintain supply voltage within Electricity Distribution Code requirement.

<u>Option 2: Reconductor the steel section ($1.44M)</u> – This option requires reconductoring of at least 8 km of steel conductor with ACSR 6/1/3.0. The cost of this option is at least $1.4M.

<u>Option 3: Install voltage regulator ($0.35M)</u> – This option requires installation of a 3-phase 50 A 32-step +/-10% voltage regulator in Riddell Rd corner of Settlement Rd.

<u>Option 4: Energy Storage ($4.64M, 10 year asset life)</u> – This option looks at installing 6MWh (1.5MVA) battery system on at SBY13 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

<u>Option 5: Demand management (2 year program) and Install voltage regulator ($0.50M)</u> – This option looks at engagement with commercial and industrial customers on feeder SBY13 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder SBY13 has potential demand reduction on commercial and industrial demand for 0.9 MVA.

<u>Option 6: Customer initiated non-network solution</u> – There are currently no proponents for demand management or embedded generation on SBY-013 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2024/25.

4.10.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the

[21] The feeder name was previously SBY-011. After SBY redevelopment project in 2018 it has been changed to SBY013.

assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–11.

Table 4–11: Summary of Present Value Analysis for Install Regulator SBY-013

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	n/a	5
2	$1.44M	$1.36M	3
3	$0.35M	$0.33M	1
4	$4.64M	$7.65M	4
5	$0.50M	$0.43M	2

4.10.4 RECOMMENDATION

It is recommended to install voltage regulator on SBY13 (Option 3) by November 2025, with a total capital expenditure of $0.35M (real 2019). It is the least cost option to provide reliable and quality supply to customer in SBY13 area.

4.11 RECONFIGURE FEEDER SBY24

4.11.1 BACKGROUND

As part of SBY redevelopment project a new feeder SBY35 has been commissioned in October 2018. The new feeder is lightly loaded and has spare capacity. On the other hand feeder SBY24 is forecast to reach 75% utilisation under 10 POE condition by summer 2024/25.

4.11.2 OPTIONS

Option 1: Do nothing – Under this option, up to 4.3 MVA of load representing approximately 1600 customers would be shed under single contingency conditions (10% POE).

Option 2: Reconfigure SBY24 and SBY35 ($1.43M) – The major works included in this option will be installation of approximately 950m of HV underground cable and installation of an Automatic Circuit Recloser (ACR) and a Manual Gas Switch (MGS).

Option 3: Install a new SBY feeder ($2.15M) – This option would involve installing approximately 1km of new 240mm^2 Al xple cables, installing at least 2km of new 19/3.25 AAC conductors and 3 ACRs. On completion of this feeder, load will be transferred from SBY32 to new feeder to manage the loading on SBY32.

Option 4: Energy Storage ($11.7M, 10 year asset life) – This option looks at installing 15.5MWh (4.5MVA) battery system on at SBY32 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 5: Demand management (2 year program) and Install a new SBY feeder ($2.06M) – This option looks at engagement with commercial and industrial customers on feeder SBY32 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder SBY32 has potential demand reduction on commercial and industrial demand for 0.4 MVA.

Option 6: Customer initiated non network solution – There are currently no proponents for demand management or embedded generation on SBY32, SBY35 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2023/24.

4.11.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–12.

Table 4–12: Summary of Present Value Analysis for Reconfigure Feeder SBY24

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$9.4834M	4
2	$1.43M	$1.35M	1
3	$2.15M	$2.02M	3
4	$11.7M	$19.30M	5
5	$2.06M	$1.77M	2

4.11.4 RECOMMENDATION

It is recommended to reconfigure feeders SBY24 and SBY35 (Option 2) by November 2024, with a total capital expenditure of $1.43M (real 2019). Hence, this project will reconfigure adjacent feeders SBY24 and SBY35 to balance the loading across these feeders and ensure they will not exceed their ratings and provide sufficient transfer capacity to adjacent feeders. It is the least cost option to provide reliable and quality supply to customer in SBY24 area.

4.12 RECONFIGURE FEEDER KLO21

4.12.1 BACKGROUND

Feeders KLO13, KLO22, COO11 and ST32 supply the rapidly growing new housing estates in the northern growth corridor.

Feeder KLO21 supplies the Quarantine Facility, and is under-utilised.

This project will reconfigure feeder KLO21 to pick up load from KLO13, and upgrade a new tie through to feeders KLO22 and ST32.

This project will enable the load to be better balanced across feeders KLO13, KLO21, KLO22, COO11 and ST32, and zone substations COO, KLO and ST, ensuring that there is sufficient capacity under system normal condition and single contingency conditions.

This project is to be completed by November 2022.

4.12.2 OPTIONS

Option 1: Do nothing – Under this option, approximately 10.4MVA of customer load needs to be shed during single contingency conditions on KLO13 (10POE demand condition) during summer 2022/23.

Option 2: Reconfigure feeder KLO21 ($3.94M) – This option would install approximately 1400m of HV cable along Donnybrook Rd to create a new tie between KLO13 and KLO21, and 1900m of HV cable along Forest Red Gum Drive, creating a new tie between feeders KLO22 and KLO13 with sufficient capacity for load transfer between these two feeders.

Option 3: Energy Storage ($24.46M, 10 year asset life) – This option looks at installing 31.5MWh (10.5MVA) battery system on at KLO-013 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 4: Demand management (2 year program) and Reconfigure feeder KLO21 ($5.46M) – This option looks at engagement with commercial and industrial customers on feeder KLO13 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder KLO13 has no commercial and industrial demand. Hence, this option is not feasible.

Option 5: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on KLO13, KLO21, KLO22, COO11, ST32 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2021/22.

4.12.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–13.

Table 4–13: Summary of Present Value Analysis for Reconfigure Feeder KLO-021

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$19.1M	3
2	$3.94M	$3.71M	1
3	$24.46M	$40.35M	4

4	$5.46M	$4.67M	2

4.12.4 RECOMMENDATION

The recommended option is to reconfigure feeder KLO21 (Option 2) by November 2022, with a total capital expenditure of $3.94M (real 2019).

4.13 COO22 AND ST32 CAPACITY CONSTRAINT

4.13.1 BACKGROUND

Feeders ST32 and COO22 supply the areas north and east of Greenvale Reservoir. Load in this area is growing rapidly due to the development of new housing estates.

Load on feeders ST32 and COO22 is forecast to reach 134% and 99% respectively under 50POE conditions in summer 2024/25. Feeder COO22 is also forecast to exceed it's rating under 10POE demand conditions in summer 2024/25.

Load on ST32 can be managed in the short term using transfers to KLO22 and COO11 (this work is included in project, BAA-DSH-000002 "COO & ST Feeder capacity constraint"); however, due to the rapidly increasing load, another project will be required to address the capacity constraints on feeders ST32 and COO22 by 30 November 2024.

4.13.2 OPTIONS

<u>Option 1: Do nothing</u> – Under this option, approximately 6.0MVA of customer load will be shed under system normal conditions (10POE demand condition) during summer 2024/25.

<u>Option 2: New ST feeder ($3.65M)</u> – This option would transfer the shutdown HV customer OneSteel ("Hume-Tubemakers") from dedicated feeder ST31 to shared feeder ST12, swap feeder exits ST24 and ST31, and construct a new feeder ST24 to offload feeders ST32 and COO22. This option involves installing three sections of new underground cable (1200m, 510m and 510m), and switching to reconfigure feeders.

<u>Option 3: Energy Storage ($15.66M, 10 year asset life)</u> – This option looks at installing 21MWh (6MVA) battery system on at ST-032 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

<u>Option 4: Demand management (2 year program) and Install a new ST feeder ($4.79M)</u> – This option looks at engagement with commercial and industrial customers on feeder ST-032 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder ST32 has potential demand reduction on commercial and industrial demand for 0.6 MVA.

<u>Option 5: Customer initiated non-network solution</u> - There are currently no proponents for demand management or embedded generation on ST32, COO22 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2023/24.

4.13.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–14.

Table 4–14: Summary of Present Value Analysis for COO022 and ST032 Capacity Constraint

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$37.48M	4
2	$3.65M	$3.44M	1
3	$15.66M	$25.83M	3
4	$4.79M	$4.08M	2

4.13.4 RECOMMENDATION

The recommended option is to reconfigure feeder ST31 by November 2024, with a total capital expenditure of $3.65M (real 2019).

4.14 AUGMENT FEEDER CS05

4.14.1 BACKGROUND

CS02 and CS05 feeder from Coburg South zone substation is forecast to reach 91.2% and 80.4% utilisation during summer 2021/22 under system normal condition (10POE demand condition). The identified need for project is to address the capacity constraints on CS05 and CS02 which are forecast to have significant load at risk under single contingency conditions due to transfer capacity limitations and downstream limitation on adjacent feeder CN05. Under this scenario, an unplanned feeder outage on CS02 would result in approximately 3.4 MVA, equivalent to around 1,600 customers would have to be shed during times of peak demand to maintain the loading on the adjacent feeders to within its thermal rating. Both CS02 and CS05 feeders supplies approximately 10,600 customers in and around the growing Coburg area.

4.14.2 OPTIONS

<u>Option 1: Do Nothing</u> – The option of doing nothing would mean there is a risk of damaging existing assets, extended interruptions of supply to customers (up to 1,600 customers) during unplanned network outages.

<u>Option 2: Augment CS05 ($0.28M)</u> – This option involves reconductoring approximately 800m of HV 105SR conductors with new 19/3.25AAC conductors on feeder CS05. The proposed works will also involves reconductoring approximately 130m of HV 65Cu conductors with new 19/3.25AAC conductors on CN05 (adjacent feeder to CS02) and replacing an HV isolator with a new manual gas switch to provide adequate transfer capability for an outage on feeder CS02.

Option 3: Reconfigure feeders CS02, CS05 and CS08 ($0.83M) – This option involves installing approximately 220m of new 300mm2 Al xple cable, install approximately 480m of new 19/3.25AAC conductors, thermal uprate approximately 135m of 19/3.25AAC conductors and one new manual gas switch. The works will allow for lightly loaded feeder CS09 to offload the highly loaded feeder CS08 and CS05 and provide sufficient transfer capacity for CS02.

Option 4: Install a new CS feeder ($1.14M) – This option would involve installing approximately 300m of new 240mm2 Al xlpe cables and approximately 1km of new 19/3.25AAC conductors. The new feeder would address the capacity shortfall on CS-02 and CS-05, however the work is estimated to be at least $1.1M, which would make the option more costly compared to Option 2.

Option 5: Energy Storage ($19.5M, 10 year asset life) – This option looks at installing 25.5MWh (7MVA) battery system on at CS05 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 6: Demand management (2 year program) and Augment CS05 ($1.31M) – This option looks at engagement with commercial and industrial customers on feeder CS05 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder CS05 has potential demand reduction on commercial and industrial demand for 0.6 MVA.

Option 7: Customer initiated non-network solution – There are currently no proponents for demand management or embedded generation on CS05 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution.

4.14.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–15.

Table 4–15: Summary of Present Value Analysis for Augment Feeder CS05

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$15.65M	5
2	$0.28M	$0.26M	1
3	$0.83M	$0.78M	2
4	$1.14M	$1.07M	3
5	$19.5M	$32.16M	6
6	$1.31M	$1.18M	4

4.14.4 RECOMMENDATION

It is recommended to augment CS05 (Option 2) by completion of November 2021, with a total capital expenditure of $0.28M (real $2019). It is the least cost option which optimises the feeder utilisation that addresses the capacity constraint and provides reliable and adequate supply to customers in the area.

4.15 NEW FEEDER HB21

4.15.1 BACKGROUND

Feeders HB14, HB15, HB22 and HB24, supplying customers in Eaglemont and Ivanhoe and south-west of Heidelberg Zone Substation (HB), are highly loaded with insufficient feeder transfer capacity in the area during single contingency conditions. HB14, HB15, HB22 and HB24 are forecast to reach 78%, 106%, 69% and 75% utilisation by summer 2023/24 respectively. In the event of an outage on HB14, HB15, HB22 or HB24, there is insufficient transfer capability to provide backup to these four feeders during peak loading periods, and up to 5.4MVA, equivalent to around 2000 customer would need to be shed at times of peak demand.

4.15.2 OPTIONS

1. <u>Option 1: Do nothing</u> – Under this option, up to 5.4MVA of load representing approximately 2000 customers would be shed under single contingency conditions (10POE demand condition).

2. <u>Option 2: New HB feeder ($3.03M)</u> – This option requires installation of approximately 2.8km of 240mm^2 AL XLPE HV underground cable. Following commissioning of the new HB feeder, there will be sufficient transfer capacity under single contingency conditions for HB14, HB15, HB22 and HB24. Following commissioning of the new HB feeder, there will be sufficient transfer capacity under single contingency conditions for HB14, HB15, HB22 and HB24.

3. <u>Option 3: Uprate HB22 and HB24 feeder backbones ($2.17M)</u> – This option requires replacement of approximately 870m of overhead conductor on HB22 and 2500m of overhead conductor on HB24. This will increase the rating of HB22 to 360A and HB24 and 325A, thereby allowing for permanent transfers to reduce utilisation levels on HB14, HB15, HB22 and HB24 to within the maximum safe loading limit during the 2020-26 regulatory period. The uprates will marginally improve transfer capacity between these feeders, however this option will not provide adequate capacity to address the capacity shortfall in the area.

4. <u>Option 4: Energy Storage ($15.75M, 10 year asset life)</u> – This option looks at installing 20.5MWh (5.5MVA) battery system on at HB-015 feeder for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

5. <u>Option 5: Demand management (2 year program) and new HB feeder ($3.85M)</u> – This option looks at engagement with commercial and industrial customers on feeder HB15 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder HB15 has potential demand reduction on commercial and industrial demand for 1.8 MVA.

6. <u>Option 6: Customer initiated non-network solution</u> – There are currently no proponents for demand management or embedded generation on HB14, HB15, HB22 and HB24. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution.

4.15.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–16.

Table 4–16: Summary of Present Value Analysis for New Feeder HB-021

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$12.49M	4
2	$3.03M	$2.85M	1
3	$2.17M	$2.04M	3
4	$15.75M	$25.98M	5
5	$3.85M	$3.28M	2

4.15.4 RECOMMENDATION

It is recommended that $3.03M (real 2019) be allocated for the construction of a new HB feeder (Option 2) rated to 375A by November 2023. This option is not the least cost option, however it is preferred over Option 3 as Option 3 only resolve a portion of load at risk due to feeder transfer limitation. Following commissioning of the new HB feeder, there will be sufficient transfer capacity under single contingency conditions for HB14, HB15, HB22 and HB24.

4.16 BD08, BD13 & ST34 CAPACITY CONSTRAINT

4.16.1 BACKGROUND

Feeders BD08, BD13 and ST34, supplying commercial/industrial customers in Campbellfield, are highly loaded with insufficient transfer capacity in the area during single contingency conditions. BD08, BD13 and ST34 are forecast to reach 80%, 83% and 93% utilisation respectively by summer 2024/25. In the event of an outage on BD08, BD13 or ST34, there is insufficient transfer capacity to provide backup to these three feeders during peak loading periods, and up to 1.6MVA, equivalent to around 50 commercial/industrial customers, would need to be shed at times of peak demand.

4.16.2 OPTIONS

<u>Option 1: Do nothing</u> – Under this option, up to 1.6MVA of load representing approximately 50 commercial/industrial customers would be shed under single contingency conditions (10POE demand condition) during summer 2024/25.

Option 2: Reconfigure feeder BD15 ($0.58M) – Under this option the existing BD15 feeder will be reconfigured to offload a section of feeder BD13. This will improved balancing of load across feeders BD08, BD13, BD15 and ST34, ensuring that there is sufficient capacity under system normal and single contingency conditions.

Option 3: Uprate feeders BD0-008 and BD0-013 ($0.62M) – This option looks at uprating feeder BD0-008 from 305A to 375A and uprating feeder BD0-013 from 315A to 375A (total 130A capacity increase). This option requires replacing approximately 510m of underground cable with new 300mm^2 Al XLPE cable. The option will ensure there is sufficient capacity under system normal and single contingency conditions. However, option 2 provides greater benefit for a lower cost, hence option 3 is not the preferred option.

Option 4: New BD feeder ($2.44M) – This option looks at creating a new feeder from BD zone substation, approximately 2.4km of underground cable with new 300mm^2 Al XLPE cable. This option will pick up sections of ST34 feeder to mitigate the load at risk

Option 5: Energy Storage ($18.92M, 10 year asset life) – This option looks at installing 19MWh (2.0MVA) battery system on feeder ST34 for demand reduction. This option requires further detailed assessment and community consultation to identify sub-optimal location for the battery system.

Option 6: Demand management (2 year program) and Reconfigure feeder BD15 ($0.81M) – This option looks at engagement with commercial and industrial customer on feeder ST34 to reduce the feeder loading during maximum demand period for up to 2 years which could potentially defer the preferred network option. Feeder ST34 has potential demand reduction on commercial and industrial demand for 1.8 MVA.

Option 7: Customer initiated non-network solution - There are currently no proponents for demand management or embedded generation on ST34 or adjoining feeders. Jemena will continue to accept non-network solution from market participants. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution by 2023/24.

4.16.3 OPTIONS ASSESSMENT

The present value of the project life-cycle cost for both network and non-network options were calculated over 45 years applying a discount rate of 6.20% (real). Energy storage option where the asset life is assumed to be 10 years will be replaced every 10-year intervals with 20% reduction in battery cost over time, based on the assumption that the maturity of these emerging technology and wider market up-take. For the demand management option, a 2 years program is assumed with the participation of commercial and industrial customer on the constrained feeder prior to implementing the preferred network option.

A summary of project costs and present value costs over the project life-cycle for each option is presented in Table 4–17.

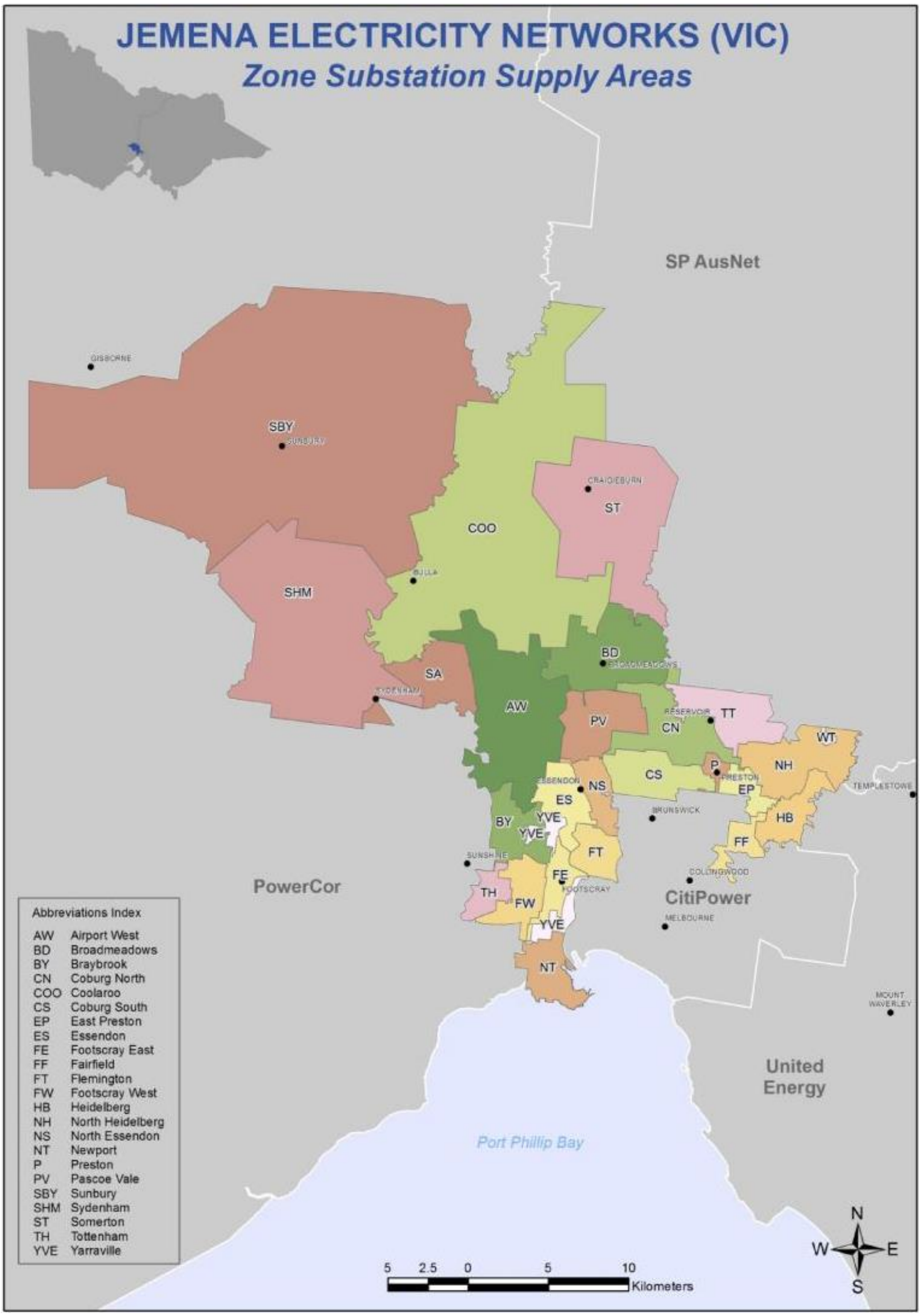
Table 4–17: Summary of Present Value Analysis for BD08, BD13 & ST34 and Capacity Constraint

Option	Project Cost (Real $2019)	Net Present Cost	Ranking
1	n/a	$3.0M	5
2	$0.58M	$0.55M	1
3	$0.62M	$0.58M	2
4	$2.44M	$2.30M	4
5	$18.92M	$31.21M	6
6	$0.81M	$0.70M	3

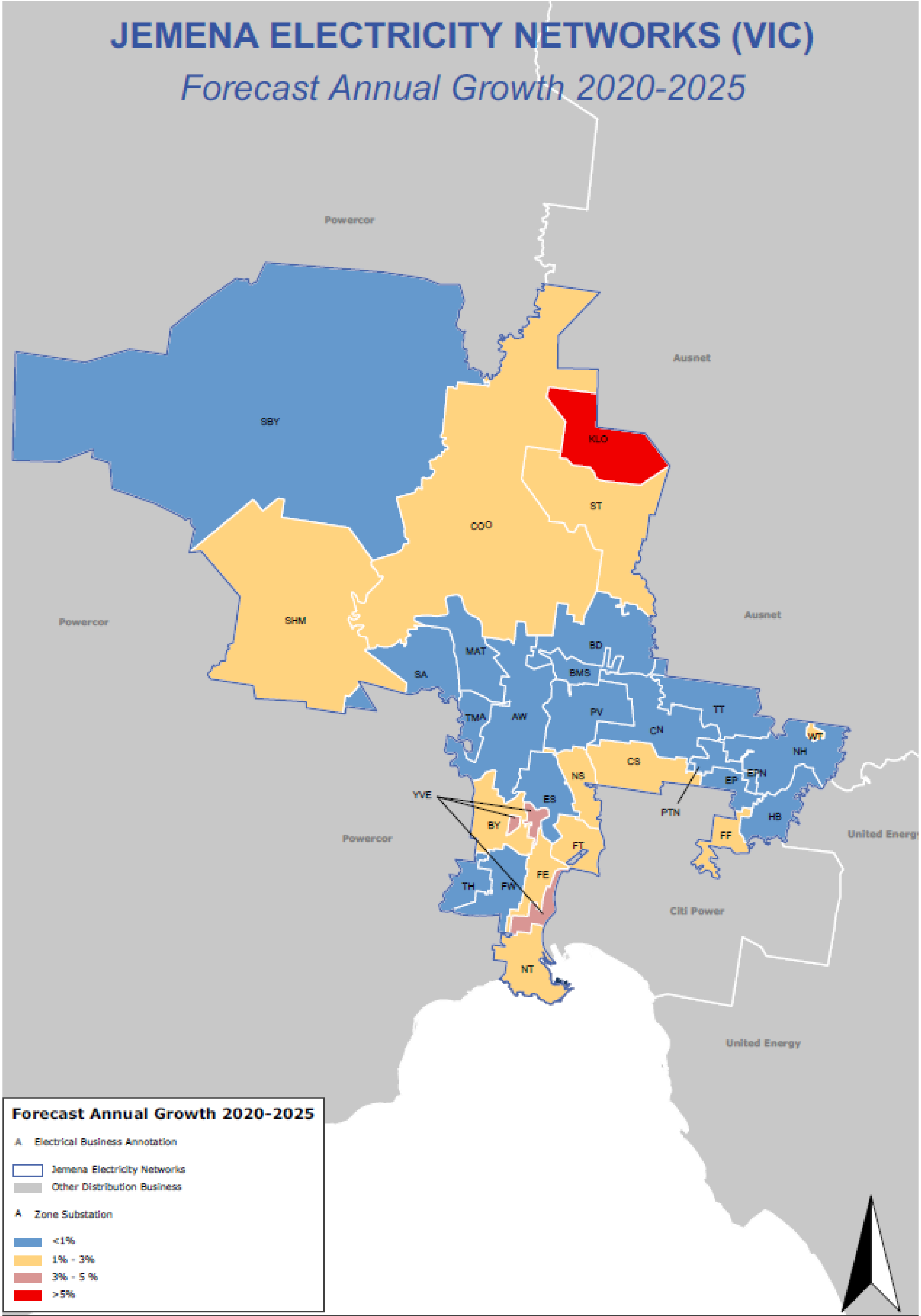
4.16.4 RECOMMENDATION

It is recommended to reconfigure feeder BD15 (Option 2) by November 2024, with a total capital expenditure of $0.58M (real 2019). It is the least cost option to provide reliable and quality supply to customer in BD5,BD8 and ST34 area.

5. APPENDIX A: JEN ZONE SUBSTATION SUPPLY AREA



6. APPENDIX B: JEN SUPPLY AREA GROWTH MAP



7. APPENDIX C: JEN FEEDER UTILISATION MAP