Jemena Electricity Networks (Vic) Ltd

Customer Initiated Capital Summary Report

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GLOSSARY

Current regulatory period	A regulatory period covering calendar year 2016 to 2020
Forthcoming regulatory period	A regulatory period covering financial year 2021/22 to 2025/26

ABBREVIATIONS

Abbreviation	Expanded Name
ACIF	Australian Industry Construction Forum
AER	Australian Energy Regulator
CB	Business Supply > 10kVA
CBE	Business Supply Project > 10kVA – LV Extension
CBG	Business Supply Project > 10kVA – Ground Substation
CBH	Business Supply Project > 10kVA – HV Customers
CBI	Business Supply Project > 10kVA – Indoor Substation
CBK	Business Supply Project > 10kVA – Kiosk Substation
CBL	Business Supply Project > 10kVA – Line of Mains
CBP	Business Supply Project > 10kVA – Pole Substation
CBS	Business Supply Project > 10kVA – Substation Modification
CD or CDA	Dual & Multiple Occupancy
CFC	Construction forecasting council
CH	Medium Density Housing URD/ PURD
CHH	Medium Density Housing – HV Extension
CHL	Medium Density Housing – LV Extension only
CIC	Customer initiated capital
CL	Public Lighting
CLA	Public Lighting Project – Major Intersection
CLI	Public Lighting Project – Minor Intersection
CLJ	Public Lighting Project – Major Scheme
CLN	Public Lighting Project – Minor Scheme
CM	Service Wire Overhead and Underground
CME	Elective Undergrounding
CMU	Underground Routine Connections < 100 Amps
CMV	Underground Routine Connections > 100 Amps
CMZ	Overhead Routine Connection < 100 Amps
COWP	Capital and operational work plan
CPI	Consumer price index
CR	Special Capital or Recoverable Works, Customer Contribution of a Non-Supply nature
CRB	Rectification of damaged assets – REC
CRE	Capital Recoverable Works – Subtransmission Asset

Abbreviation	Expanded Name
CRP	Capital Recoverable Works – In Line Poles / Stays
CRR	Capital Recoverable Works – Intersection Realignment
CRS	Capital Recoverable Works – Substation Modification
CRU	Capital Recoverable Works – Undergrounding of Assets
CRV	Capital Recoverable Works – Major Vic Roads
CS	Low Density & Small Business Supplies < 10kVA
CSO	Low Density & Small Business Development < 10kVA – Overhead Extension
CSU	Low Density & Small Business Development < 10kVA – Underground Extension
EUSE	Expected unserved energy
HV	High Voltage, which can either be 22kV, 11kV or 6.6kV
JEN	Jemena Electricity Networks
LCTA	Least Cost Technically Acceptable
LV	Low Voltage, which is measured at 400V 3-phase or 230V single-phase
NER	National Electricity Rules
POE	Probability of Exceedence, where 50% POE is considered having a 1-in-2 years chance of occurring and 10% POE is considered having a 1-in-10 years of occurring
RIN	Regulatory information notice
RIT-D	Regulatory Investment Test for Distribution
The Rules	National Electricity Rules
TNSP	Transmission network service provider
URD	Underground Residential Distribution
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code

EXECUTIVE SUMMARY

Jemena Electricity Networks (JEN) is responsible for planning and developing its distribution network, as well as planning and directing the augmentation of its connection points with the transmission network, which are owned and maintained by the relevant transmission network service provider (TNSP).

JEN is responsible to provide connection services and supply to customers and generators, undergrounding or asset relocation services, public lighting services, distribution services to other distributors and other excluded services. These distribution services are referred to as either direct control services or negotiated distribution services, and are classified by the Australian Energy Regulator (AER) in accordance with the National Electricity Rules (the Rules). Capital investments of these services are commonly referred to as customer connections capital or customer initiated capital (CIC). The terms are used interchangeably.

A number of regulatory instruments define JEN's obligations to provide direct control services and negotiated distribution services to customers. The regulatory instruments that set JEN's obligations to offer direct control services and negotiated distribution services to customers include JEN's Electricity Distribution Licence, Victorian Electricity Distribution Code (VEDC) and the Rules.

Forecast Approach

The Rules and National Electricity Objective require distributors to develop efficient and prudent capital expenditure forecasts. For this reason, JEN adopts a robust forecasting approach in relation to capital expenditure plans. In particular, JEN combines a 'top down' modelling to forecast expenditure required for the different market sectors using specific sector economic growth, with the 'bottom up' assessment to capture the volume and descriptor metric expenditure.

The 'top-down' CIC expenditure forecast is central to JEN's CIC gross expenditure plan. Key input to the 'top down' modelling comes from independent sources, in particular, the residential sector data comes from independent consultant Acil Allen, commercial and industrial sector data comes from the Australian Construction Market Report prepared by the Australian Construction Industry Forum (ACIF), and major customer developments come from JEN's direct engagement with its customers.

JEN's forecasting methodology and augmentation planning method deliver efficient outcomes for customers, and therefore complies with the Rules requirements.

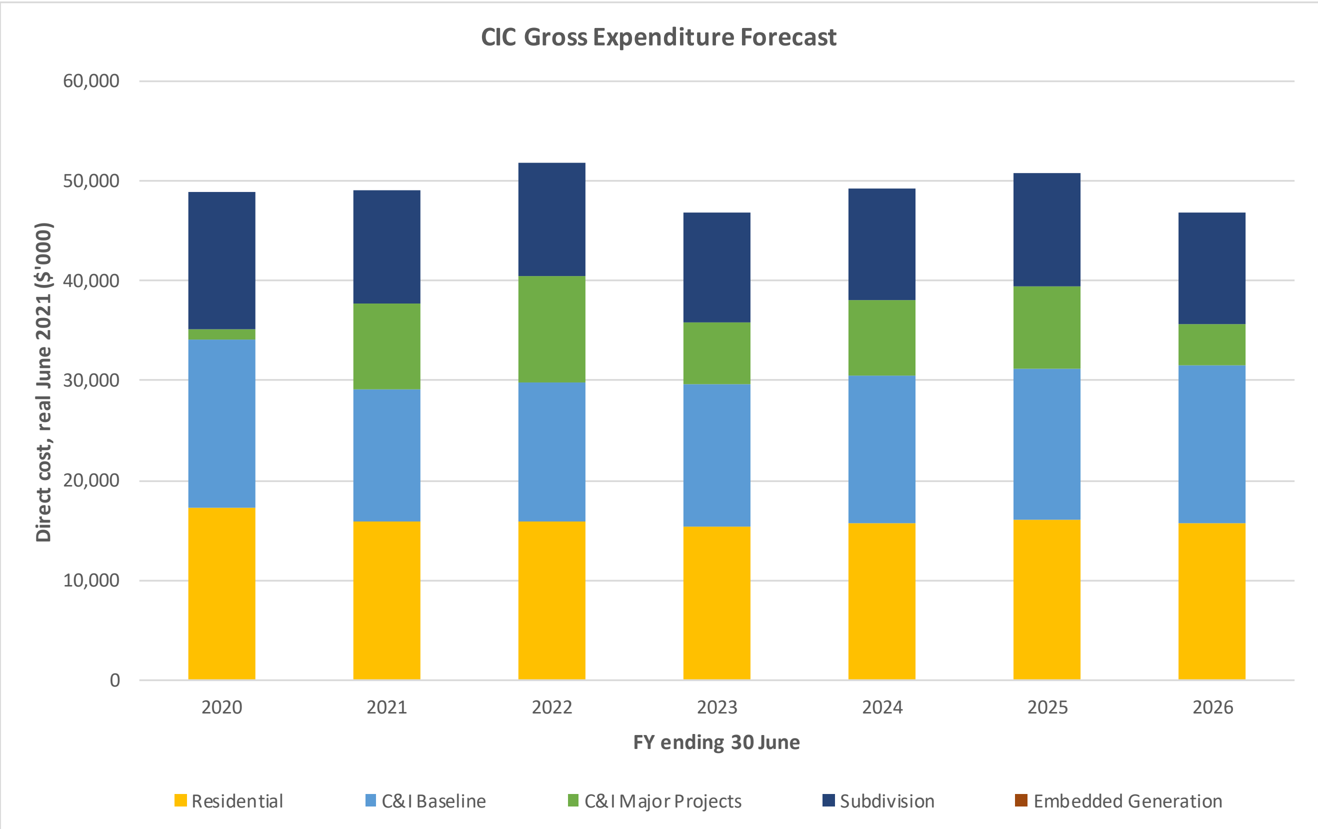
Forecast Expenditure

Table 0-1 and Figure 0-1 present a summary of the CIC gross expenditure forecasts that will be required over the forthcoming regulatory period in order to meet the expected demand for customer initiated works for each of the connection subcategory (residential, commercial & industrial, subdivision and embedded generation).

Table 0-1: CIC gross expenditure forecast over the forthcoming regulatory period

Connection Subcategory	Financial year ending 30 June (direct cost, real June 2021 ($'000)							
	2020	2021	2022	2023	2024	2025	2026	Total (FY2022-26)
Residential	17,276	15,959	15,842	15,413	15,705	16,003	15,723	78,686
Commercial & Industrial								
- Baseline	16,819	13,265	13,904	14,241	14,760	15,262	15,768	73,935
- Major Projects	1,129	8,539	10,835	6,251	7,647	8,191	4,151	37,075
Subdivision	13,704	11,330	11,212	10,920	11,138	11,362	11,175	55,806
Embedded Generation	0	0	0	0	0	0	0	0
Total	**48,927**	**49,093**	**51,794**	**46,825**	**49,250**	**50,817**	**46,816**	**245,503**

Figure 0-1: CIC gross expenditure forecast over the forthcoming regulatory period



1. INTRODUCTION

1.1 PURPOSE

The purpose of this report is to explain JEN's CIC expenditure forecasts in the forthcoming regulatory period as one of the key drivers of its capital expenditure plans.

This report seeks to explain JEN's approach and methodology to customer connection planning and the capital expenditure forecast in the forthcoming regulatory period that is necessary to meet customer's needs. In particular, the report explains that:

- JEN adopts a robust forecasting approach in relation to capital expenditure plans. In particular, JEN combines a 'top down' modelling to forecast expenditure required for the different market sectors, with the 'bottom up' assessment to capture the volume and descriptor metric expenditure; and
- JEN's expenditure forecasting and connection planning approach delivers augmentation plans that are prudent and efficient.

1.2 SCOPE

This report provides a summary of the following matters:

- Network planning approach to customer connection;
- CIC gross expenditure forecasts for the forthcoming regulatory period;
- CIC gross expenditure forecasting methodology;
- An explanation of why JEN's approach complies with the Rules requirements and the National Electricity Objective; and
- Details of major customer network development plans.

This document is a summary report. Further detailed analysis and supporting information is provided in the following documents:

- Customer Connections Capital Forecast Methodology (ELE PR 0019);
- Acil Allen's JEN Demand Forecasts 2019-2028 Report;
- Australian Construction Market Report (May 2019);
- JEN Network Augmentation Planning Criteria (JEN PR 0007);
- JEN CIC Forecast Model (2019-2026)_Final V1.0.xlsx; and
- Workbook 1 – Regulatory determination, regulatory template 2.5.

2. NETWORK PLANNING APPROACH TO CUSTOMER CONNECTION

The purpose of this chapter is to explain the network planning approach to customer connection works which is consistent with JEN's network augmentation planning criteria[1]. This chapter therefore provides the following information:

- Section 2.1 provides an overview of the network planning methodology, which is principally probabilistic planning;
- Section 2.2 explains the approach to network limitation assessments;
- Section 2.3 explains the concept of energy at risk;
- Section 2.4 explains the concept of expected unserved energy; and
- Section 2.5 sets out concluding observations, which is relevant for customer connection works.

2.1 OVERVIEW OF NETWORK PLANNING METHODOLOGY

JEN adopts two analytical planning methodologies:

- The probabilistic method, which is the standard planning approach in Victoria, and is regarded as good practice. It is consistent with the regulatory investment test for distribution (RIT-D), which is specified in the Rules. This method is applied to network assets with the most significant constraints and associated augmentation costs, including:
  - Transmission connection points;
  - Sub-transmission lines;
  - Zone substations;
  - High-voltage (HV) feeder lines when demand is forecast up to the maximum safe loading limit.
- The deterministic method, which is a simplified approach that is only applied to:
  - HV feeder lines when demand is forecast to exceed the maximum safe loading limit;
  - Distribution substations and associated low-voltage (LV) networks;
  - Connection assets works or network extensions based on Least Cost Technically Acceptable (LCTA) standard necessary for the load connection, unless the connection applicant requests a connection service, or part thereof, to be performed to a higher standard. In such case, the connection applicant will be required to pay the additional cost of providing the service to the higher standard in which a deterministic method is used for such works.

Probabilistic planning, which is JEN's principal planning method, is a cost-benefit approach to network augmentation, which compares:

- The expected amount (and value) of energy that will not be supplied under a 'do nothing' option; and

[1] Refer to JEN Network Augmentation Planning Criteria (JEN PR 0007).

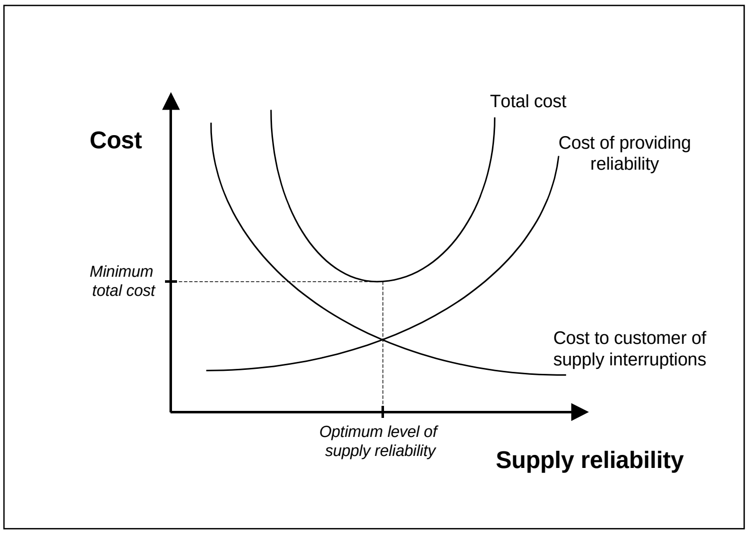
- The expected cost of feasible network and non-network options that would reduce or eliminate the identified network capacity issue.

The option that maximises the net benefit, which includes the 'do nothing' option, is selected.

An important aspect of probabilistic planning is that it exposes customers to the risk that network capacity may not be sufficient to meet actual demand. Under this planning approach, action is only taken to address the risk of a capacity shortage if this outcome is less costly to customers than the expected cost of the outage. It should be noted that one source of risk is the demand forecast, especially as weather may have a significant impact on actual demand. For this reason, maximum demand forecasts are reported on a probability of exceedance (POE) basis, to denote the probability that the actual demand will exceed the forecast.

The planning approach requires us to estimate the expected costs of 'doing nothing', and to determine whether 'doing something' minimises total costs to customers. This approach is illustrated in the figure below.

Figure 2-1: Minimising the total costs to customers



Source: JEN, Network Augmentation Planning Criteria- Technical Methodology, Inputs and Assumptions, JEN PR 0007.

The practical application of probabilistic planning involves four key stages:

- Network limitation assessment, which involves determining the extent of network constraints for various network contingencies and demand forecast scenarios;
- Energy at risk analysis, where the annual energy at risk of not being supplied as a result of these network constraints is identified;
- Expected unserved energy (EUSE) calculation, which considers the probability of the forecast demand and contingency occurring, and weights the energy at risk by that probability to determine an expected amount of unserved energy;
- Calculating the cost of EUSE, where the EUSE is transformed into a dollar cost by multiplying the value of customer reliability (VCR) by the expected unserved energy.

Comments on the first three steps of the probabilistic planning approach will be discussed in the remainder of this chapter.

2.2 NETWORK LIMITATION ASSESSMENT

A network limitation is assessed by comparing the peak asset loading (under a range of different scenarios and network contingencies) with the asset's rating for each year in the forward planning period. The comparison identifies the extent to which asset overload will occur without corrective action.

The analysis of network limitations includes the following key inputs and assumptions:

- Season (winter and/or summer). Although the network is typically summer peaking, both periods are assessed because there may be some circumstances when a winter peak will exceed the relevant winter rating of assets;
- Probability of exceedance (POE), which defines the likelihood that the actual maximum demand (which results in EUSE) will differ from the forecast due to more extreme or benign temperature conditions;
- The expected levels of embedded generation and demand-side support, which can affect the asset loading. However, it is assumed that embedded generation is not available at times of maximum demand unless network support contracts are in place;
- Contingencies, which can significantly affect asset loading. JEN considers loading for both system-normal conditions and following the most credible single contingency;
- Pre and post-contingent operator actions, which can affect asset loading and the maximum load limit (and therefore the EUSE) are considered. Specifically, JEN considers likely operator actions given the relevant contingency conditions.

It is important to note that the network limitation assessment is asset-specific and location specific. JEN must have regard to the actual conditions 'on the ground'. Spatial demand forecasts, which recognise variations in the level of demand and the expected rate of growth in demand across the network, are essential inputs to the network limitation assessment.

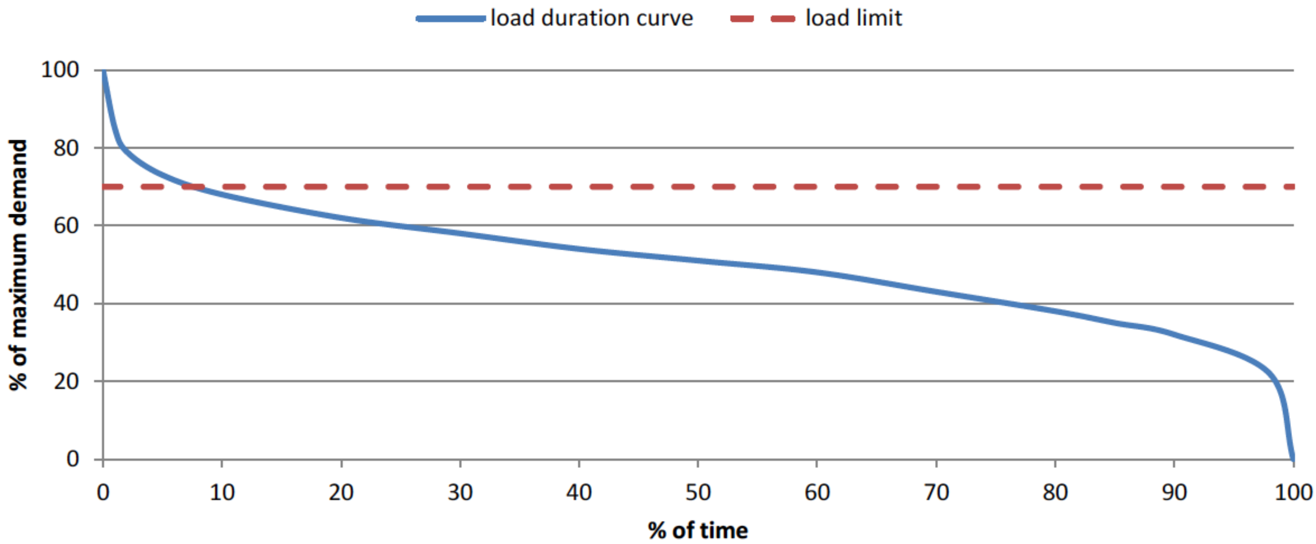
2.3 ENERGY AT RISK ANALYSIS

Energy at risk refers to the total energy that may not be supplied under contingency events, particularly around the maximum demand period. A contingency event refers to the loss or failure of part of the network, with N-1 referring to the loss of one critical element, such as a transformer.

Energy at risk can be approximated by using a load duration curve that reflects the maximum demand scenario for a given asset. It is calculated as the amount of energy under the load duration curve, but above the asset load limit (where the load limit is typically the asset's N-1 rating). The load duration curve is typically based on representative historical hourly load data scaled to the forecast maximum demand.

Figure 2-2 shows a load duration curve with a horizontal line representing the load limit following a specific contingency for a particular terminal station, zone substation or feeder.

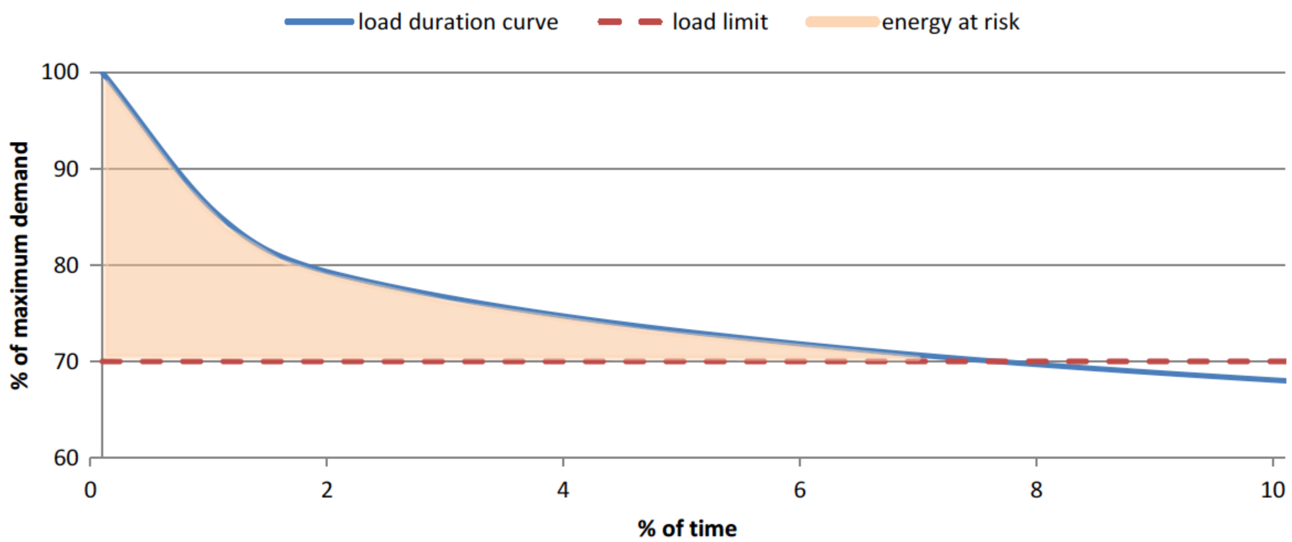
Figure 2-2: Load duration curve and load limit relationship



Source: JEN, Network Augmentation Planning Criteria- Technical Methodology, Inputs and Assumptions, JEN PR 0007.

Figure 2-3 shows the same figure, magnified around that part of the load duration curve closest to maximum demand. This effectively illustrates the energy at risk calculation, which is represented by the area under the load duration curve and above the load limit.

Figure 2-3: Energy-at-risk calculation for the area of the load duration curve above the load limit



Source: JEN, Network Augmentation Planning Criteria- Technical Methodology, Inputs and Assumptions, JEN PR 0007.

2.4 EXPECTED UNSERVED ENERGY

For a specific maximum demand scenario and contingency, the EUSE measure in megawatt hours (MWh) is the product of:

- The energy at risk calculated for a given network state; and

- The probability of being in that network state.

Typically, the probability of being in an N-1 contingency is determined by the probability of a transformer outage or sub-transmission line outage.

2.5 KEY OBSERVATIONS

As explained in section 2.1, JEN adopts two analytical planning methodologies, being probabilistic method and deterministic method. Most (if not all) of the customer connection works are using deterministic method where it involves one of the following:

- HV feeder lines when demand is forecast to exceed the maximum safe loading limit;
- Augmentation of distribution substations and/ or associated low-voltage (LV) networks to meet customer's needs; or
- Connection assets works or network extensions based on Least Cost Technically Acceptable (LCTA) standard necessary for the load connection, unless the connection applicant requests a connection service, or part thereof, to be performed to a higher standard. In such case, the connection applicant will be required to pay the additional cost of providing the service to the higher standard in which a deterministic method is used for such works.

Over the forward planning period up to 2026, it is unlikely that there will be any augmentation to the shared network including:

  - Transmission connection points;
  - Sub-transmission lines;
  - Zone substations;
  - High-voltage (HV) feeder lines when demand is forecast up to the maximum safe loading limit.

Should there be any augmentation to the shared network at these network levels, a probabilistic method will be applied to determine whether the works are required.

JEN considers its planning approach to customer connection works is consistent with JEN's network augmentation planning criteria.

3. CIC GROSS EXPENDITURE FORECASTING METHODOLOGY

The purpose of this chapter is to explain the CIC gross expenditure forecasting methodology.

It explains that global level (i.e. top-down) capital expenditure forecast, which are central to the gross connection plans, and a spatial level (i.e. bottom-up) forecast for the descriptor metric volume and expenditure which are reconciled to the global level forecast.

3.1 OVERVIEW

The methodology for preparing CIC forecast calls for two sets of forecasts as follows:

- a global level (ie top-down) CIC expenditure forecast by SAP service codes; and
- a spatial level (ie bottom-up) forecast for the descriptor metric volume and expenditure in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – regulatory determination, regulatory template 2.5) using the global level forecast output as the growth index.

JEN reconciles its spatial forecasts to the global level forecast to produce the final set of descriptor metric volume and expenditure forecast in Tables 2.5.1, 2.5.2 and 2.5.3 of workbook 1 – regulatory determination, regulatory template 2.5. Both sets of forecasts are adopted for connection planning purposes.

The global and spatial level forecasting methodologies are discussed in turn below.

3.2 Global level gross connections capex forecast

The methodology for the global level CIC expenditure forecast by SAP service codes is documented in the methodology paper titled “Jemena Electricity Networks, Customer Connections Capital Forecast Methodology” and are summarised below.

The base data and model input data, which comes from independent sources, include:

- Actual CIC expenditure from prior years to determine the base year data (2-letter SAP service codes) and expenditure split (3-letter SAP service codes);
- Forecast of residential customer numbers produced by JEN’s independent consultant Acil Allen;
- Australian Construction Market Report prepared by the Australian Construction Industry Forum (ACIF); and
- Major customer developments that are specific to JEN supply area comes from JEN’s direct engagement with its customers, that is above the baseline growth expected to derive from the macro-economic indices.

The growth rates calculated for the forecasts are:

- For activities CD, CH, CL and CM – the model assumes that the forecasts are driven by economic growth in the residential sector. Economic growth in residential sector is, in turn, driven by growth in customer numbers; hence Acil Allen forecasts are used; and

- For activities CB, CR and CS - the model assumes that the forecasts are driven by economic growth in commercial and industrial sectors.
    - For activities CB and CS - economic forecasts by ACIF for "Melbourne non-residential sector (industrial, other commercial & miscellaneous)" is used; and
    - For activity CR - economic forecasts by ACIF for "Victoria engineering sector (roads & bridges railways harbours)" is used.

The output of the forecasting model is in annual forecasts for the following activities, which are further split into 3-letter SAP service codes: From the 3-letter SAP service codes, the output can be grouped into the relevant service classification using the mapping table in Table 3-1.

- CH Medium density housing;
    - CHH and CHL
- CL Public lighting;
    - CLA, CLI, CLJ, CLN
- CD Dual and multiple occupancy;
    - CDA
- CB Business supply > 10kVA;
    - CBE, CBG, CBH, CBI, CBK, CBL, CBP and CBS
- CS Low density/ small business supplies < 10kVA;
    - CSO and CSU
- CM Service wire;
    - CME, CMU, CMV and CMZ
- CR Recoverable works.
    - CRB, CRE, CRP, CRR, CRS, CRU and CRV

Table 3-1: Customer connection activities and service classification over the forthcoming regulatory period RY2022-26

Service (Activity) Code	Description	Service classification
CB	Business Supply > 10kVA	Direct control service (standard control service)
CD	Dual & Multiple Occupancy	Direct control service (standard control service)
CH	Medium Density Housing URD/PURD	Direct control service (standard control service)
CL	Public Lighting	Direct control service (alternative control service)
CM	Service Wire Overhead and Underground	Direct control service (alternative control service)
CR	Capital Recoverable Works	Direct control service (standard control service)
CS	Low Density & Small Business Supplies < 10kVA	Direct control service (standard control service)

Refer to “JEN CIC Forecast Model (2019-2026)_Final V1.0.xlsx” for details of forecasting model.

3.3 Spatial level gross connections capex forecast

The spatial level forecast methodology for the descriptor metric volume and expenditure (in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – Regulatory determination, regulatory template 2.5) is derived using the connection subcategory forecast expenditure and 2018 actual expenditure ratio, multiplied by the 2018 actual descriptor metric volume or expenditure as the ‘base’ year. The forecast volumes by connection classification in Table 2.5.3 are further split into new connections and upgrade to existing connections using a sample of projects for each connection subcategory.

The connection subcategory expenditure forecast is derived from the global level connections capex forecast output using SAP service code mapping method. Essentially, the descriptor metric volume and expenditure forecast in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1 – Regulatory determination, regulatory template 2.5 is growing or declining at the same rate as the connection subcategory expenditure level.

The table below provides a more detailed calculation methodology for each variable in Tables 2.5.1, 2.5.2 and 2.5.3 of Workbook 1.

Base information		Data Type		Population approach		
Table number	Table Name	Actual Historical and/or Estimated Historical, Forecast	Reasons For estimation	Source	Methodology	Assumptions
2.5.1	DESCRIPTOR METRICS	Forecast	Not Applicable	Source of historical data used to derive 'Base Volume' and 'Base Expenditure' is Category Analysis RIN – Template 2.5. Source used to derive forecast volume and forecast expenditure is JEN EDPR CAPEX Forecast Model. Source used for forecast connection volume for embedded generation is "ACIL Allen's JEN Demand Forecasts 2019-2028 Report" For connections capital expenditure forecast methodology and SAP service codes definitions, refer to document "JEN Customer Connections Capital Forecast Methodology,". For Workbook 1 regulatory template 2.5 (connections) forecast model, refer to Excel spreadsheet named "JEN CIC Forecast Model (2019-2026)_Final V1.0.xlsx"	In general, the forecast methodology for volume and expenditure is derived from the connection subcategory forecast expenditure and 2018 actual expenditure ratio, using the 2018 actual volume and expenditure as the 'base' year. The formulae for each descriptor metric is described below. Forecast underground connections & overhead connections volume for connection subcategory "Residential, Commercial/ Industrial or Subdivision" is derived from the following equation: $$V_n = V_b * \frac{E_n}{E_b}$$ Where: V_n is the forecast underground or overhead connections volume in year n; V_b is the 'base' underground or overhead connections volume, derived from the 2018 actual underground and overhead total connections volume multiplied by the 2016-18 average underground or overhead connections volume ratio; E_n is the "Residential, Commercial/ Industrial or Subdivision" forecast expenditure in year n (direct cost, real June 2018 $); E_b is the "Residential, Commercial/ Industrial or Subdivision" actual expenditure in 2018 (direct cost, real June 2018 $); Forecast connection volume for Embedded Generation is taken from Acil Allen's forecast Forecast volume for distribution substations (MVA & number), HV and LV circuit length (km) for connection subcategory "Residential, Commercial/ Industrial, Subdivision & Embedded Generation" is derived from the following equation:	It is assumed that the forecast volume is growing at the same rate as the forecast expenditure. This assumption is considered reasonable as all the expenditure used in the forecast volume is based on direct cost, real June 2018 $, and any increase or decrease in the expenditure level is expected to result in similar output in the volume. Forecast descriptor metric expenditure within each connection subcategory is assumed to have the same ratio or split as the 2018 actual expenditure allocation. This assumption is considered reasonable as this is representative of the general expenditure allocation within each connection subcategory.

Base information		Data Type		Population approach		
Table number	Table Name	Actual Historical and/or Estimated Historical, Forecast	Reasons For estimation	Source	Methodology	Assumptions
					$$V_n = V_b * \frac{E_n}{E_b}$$ Where: V_n is the forecast volume for distribution substations (in MVA or number), HV or LV circuit length (in km) in year n; V_b is the 'base' distribution substations (in MVA or number), HV or LV circuit length (in km) derived from 2018 actual volume; E_n is the "Residential, Commercial/ Industrial, Subdivision or Embedded Generation" forecast expenditure in year n (direct cost, real June 2018 $); E_b is the "Residential, Commercial/ Industrial, Subdivision or Embedded Generation" actual expenditure in 2018 (direct cost, real June 2018 $); Forecast expenditure for distribution substations, HV and LV circuit augmentation for connection subcategory "Residential, Commercial/ Industrial, Subdivision & Embedded Generation" is derived from the direct Maintenance Activity Type (MAT) code mapping for each descriptor metric. • JEN commenced in 2012/13 the use of Maintenance Activity Type (MAT) code to better capture expenditure. • With that, SCS and ACS Connection expenditure can be clearly distinguished. • ACS Connection expenditure is relevant to Residential connections only. • Therefore, Residential connection attributable to ACS (distinguished via the use of MAT code) are excluded from SCS expenditure. 2020-2026 forecast for "Residential 'Mean days to connect residential customer with LV single phase	

Base information		Data Type		Population approach		
Table number	**Table Name**	**Actual Historical and/or Estimated Historical, Forecast**	**Reasons For estimation**	**Source**	**Methodology**	**Assumptions**
					connection', 'Volume of GSL breaches for residential customers', 'Volume of customer complaints relating to connection services' and 'GSL payments' " was prepared based on the average performance for CY16 and CY18 and assumed to be constant. It was determined that CY17 was an outlier year and has been removed from trend analysis to minimise the skewness of the forecast results. Forecast for "Subdivision 'Cost per lot' " is determined by the 'sum of subdivision expenditure' divided by 'sum of underground & overhead connections'.	
2.5.2 and 2.5.3	COST METRICS BY CONNECTION CLASSIFICATI ON VOLUMES BY CONNECTION CLASSIFICATI ON	Forecast	Not Applicable	Source of historical data used to derive 'Base Volume' and 'Base Expenditure' is Category Analysis RIN – Template 2.5. Source used to derive forecast volume and forecast expenditure is JEN EDPR CAPEX Forecast Model. Source used for forecast connection volume for embedded generation is "ACIL Allen's JEN Demand Forecasts 2019-2028 Report". For connections capital expenditure forecast methodology and SAP service codes definitions, refer to document "JEN Customer Connections Capital Forecast Methodology". For Workbook 1 regulatory template 2.5 (connections) forecast model, refer to Excel spreadsheet named "JEN CIC Forecast Model (2020-2026)_Final_V1.0.xlsx"	In general, the forecast methodology for volume and expenditure is derived from the connection subcategory forecast expenditure and 2018 actual expenditure ratio, using the 2018 actual volume and expenditure as the 'base' year. The formulae for each connection classification is described below. The forecast expenditure for each connection classification is determined by mapping each connection classification to the SAP service codes and using the JEN EDPR Capex Forecast Model for the expenditure. The following summarises this mapping between connection classification and the SAP service codes. Residential Simple Connection LV is equivalent to service codes 'Dual and Multiple Occupancy (CD)' and 'Services (CM)'. Residential Complex Connection LV and Residential Complex Connection HV are generally not applicable. Commercial/ Industrial Simple Connection LV is equivalent to service codes 'Low Density and Small Business (CS)' and 'Business Supply Project > 10kVA – LV Extension (CBE).	It is assumed that the forecast volume is growing at the same rate as the forecast expenditure. This assumption is considered reasonable as all the expenditure used in the forecast volume is based on direct cost, real June 2018 $, and any increase or decrease in the expenditure level is expected to result in similar output in the volume.

Base information		Data Type		Population approach		
Table number	Table Name	Actual Historical and/or Estimated Historical, Forecast	Reasons For estimation	Source	Methodology	Assumptions
					Commercial/ Industrial complex connection HV (customer connected at LV, minor HV works) & complex connection HV (customer connected at LV, upstream asset works) is equivalent to service codes 'CBG, CBI, CBK, CBL, CBP & CBS'. It is assumed that these service codes expenditure is split using the ratio of the 2018 actual expenditure into 'minor HV works' and 'upstream asset works'. Commercial/ Industrial complex connection HV (customer connected at HV) is equivalent to service code 'Business Supply Project > 10kVA – HV Customers (CBH)'. Currently, Commercial/ Industrial complex connection sub-transmission is captured under service code 'CBH' and is separated using major customer projects expenditure (actual or forecast) connected at sub-transmission voltage. Subdivision complex connection LV is equivalent to service code 'Medium Density Housing – LV Extension Only (CHL)'. Subdivision complex connection HV (no upstream asset works) is equivalent to service code 'Medium Density Housing – HV Extension (CHH)'. There is no subdivision complex connection HV (with upstream asset works). Expenditure forecast for Embedded Generation is zero. Forecast volume for each connection classification is derived from the following equation: $V_n = V_b * \frac{E_n}{E_b}$ Where:	

Base information		Data Type		Population approach		
Table number	Table Name	Actual Historical and/or Estimated Historical, Forecast	Reasons For estimation	Source	Methodology	Assumptions
					Vn is the forecast volume for a connection classification in year n; Vb is the 'base' volume for a connection classification, derived from 2018 actual volume; En is a connection classification forecast expenditure in year n (direct cost, real June 2018 $); Eb is a connection classification actual expenditure in 2018 (direct cost, real June 2018 $); Embedded generation simple connection LV forecast volume is taken from Acil Allen's forecast	

For Workbook 1 regulatory template 2.5 forecast model, refer to "JEN CIC Forecast Model (2020-2026)_Final V1.0.xlsx" Excel spreadsheet.

4. CIC EXPENDITURE FORECASTS FOR 2020-2026

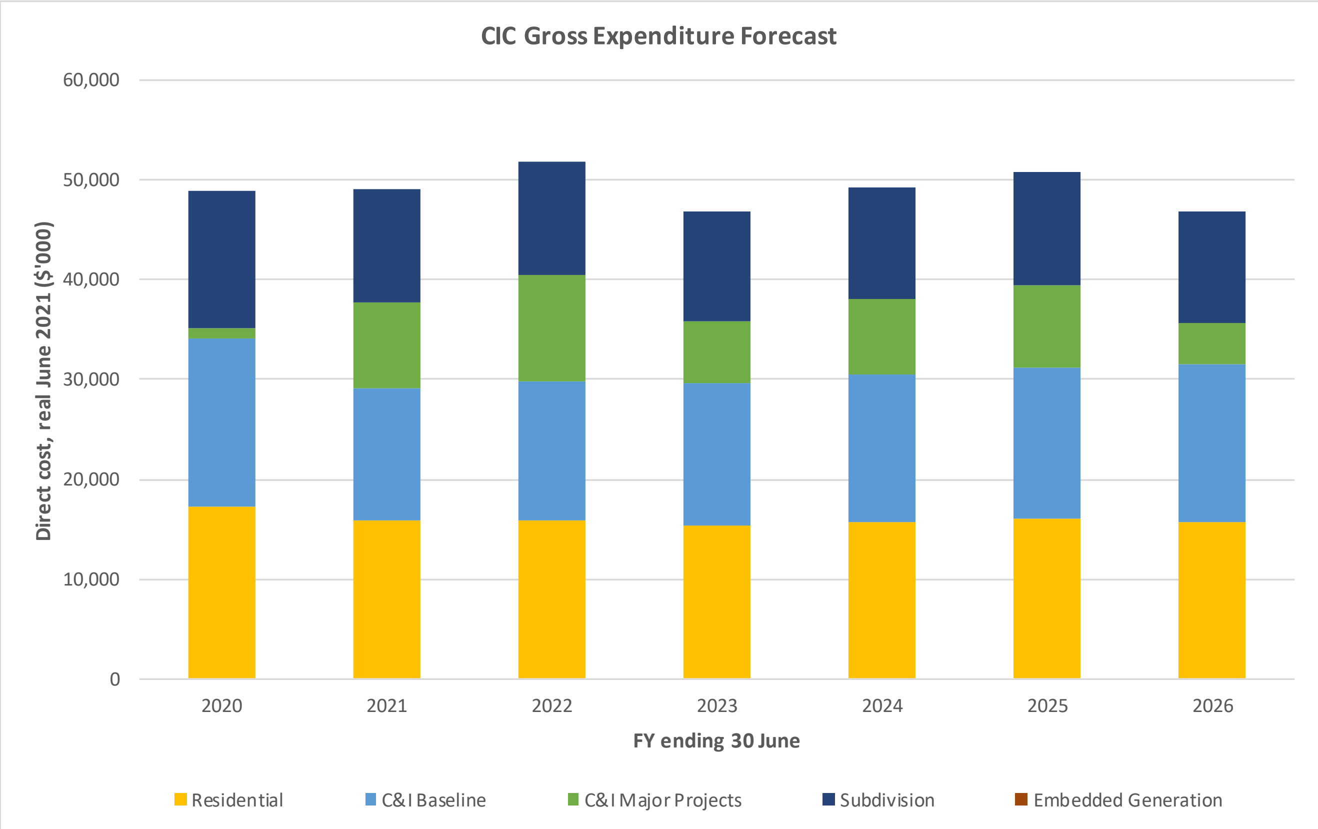
The purpose of this chapter is to summarise the CIC gross expenditure forecasts for the forthcoming regulatory period. As explained in Section 3, the global level forecasts are central to JEN's efficient connection planning.

Table 4-1 and Figure 4-1 present a summary of the CIC gross expenditure forecasts that will be required over the forthcoming regulatory period in order to meet the expected demand for customer initiated works for each of the connection subcategory (residential, commercial & industrial, subdivision and embedded generation).

Table 4-1: CIC gross expenditure forecast over the forthcoming regulatory period

Connection Subcategory	Financial year ending 30 June (direct cost, real June 2021 $'000)							
	2020	2021	2022	2023	2024	2025	2026	Total (FY2022-26)
Residential	17,276	15,959	15,842	15,413	15,705	16,003	15,723	78,686
Commercial & Industrial								
- Baseline	16,819	13,265	13,904	14,241	14,760	15,262	15,768	73,935
- Major Projects	1,129	8,539	10,835	6,251	7,647	8,191	4,151	37,075
Subdivision	13,704	11,330	11,212	10,920	11,138	11,362	11,175	55,806
Embedded Generation	0	0	0	0	0	0	0	0
Total	**48,927**	**49,093**	**51,794**	**46,825**	**49,250**	**50,817**	**46,816**	**245,503**

Figure 4-1: CIC gross expenditure forecast over the forthcoming regulatory period



5. DEMONSTRATING RULES COMPLIANCE

The purpose of this chapter is to set out the principal regulatory obligations that are relevant to the tasks of preparing customer connections forecasts and capital expenditure plans. The chapter concludes by explaining why JEN's approach to these tasks complies with these Rules requirements.

5.1 RELEVANT REGULATORY OBLIGATIONS

Clause 6.5.7(a) of the National Electricity Rules (the Rules) requires a building block proposal to include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):

(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) maintain the quality, reliability and security of supply of standard control services;

(4) maintain the safety of the distribution system through the supply of standard control services.

In addition, Clause 6.5.7(c) of the Rules also requires the forecast expenditure to reasonably reflect each of the following capital expenditure criteria:

(1) the efficient costs of achieving the capital expenditure objectives;

(2) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

Clause 16(1) of the National Electricity Law requires the AER to exercise its economic regulatory function or power in a manner that will or is likely to contribute to the achievement of the National Electricity Objective. Section 7 of the NEL states that:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

A number of other regulatory instruments that define JEN's obligations to provide direct control services and negotiated distribution services to customers. Important points relevant to these services include the following:

- JEN's Electricity Distribution Licence (Chapters 6 to 12) sets the obligations for JEN to offer connection services and supply to customers and embedded generators, undergrounding or asset relocation services, public lighting services, distribution services to other distributors and other excluded services;

- The AER determines the classification of services for JEN for each regulatory control period, in accordance with clause 6.2.1(a) and 6.12.1 (1) of the Rules;
- Chapter 5 – Part A – Network Connection of the Rules sets the framework for connection to the JEN network; and
- The VEDC (Chapter 2 – Connection of Supply) requires JEN to use best endeavours to connect the customer and sets out various obligations in relation to connection of supply.

5.2 OBSERVATIONS FOR CONNECTION PLANNING AND CAPITAL EXPENDITURE FORECASTING

In relation to connection planning and connection capital expenditure, the following observations can be drawn in relation to the regulatory provisions noted in section 5.1:

- JEN's capital expenditure forecasts must meet or manage the expected demand for standard control services (Clause 6.5.7(a)(1) of the Rules). Due to the nature of the customer connection demand, JEN considers the global level total forecast capital expenditure a realistic demand forecast, referred to in Clause 6.5.7(c)(3). A global level or network-wide capital forecast would be reasonable given the input cost into the forecasting model is also at the network level which enable JEN to "meet or manage the expected demand for standard control services."
- The capital expenditure criteria require JEN to take an efficient and prudent approach in determining the costs of achieving the capital expenditure objectives (clauses 6.5.7(c)(1) and (2) of the Rules). JEN's approach to connection planning and capital forecast are based on economic growth in the residential, commercial and industrial sectors, delivers efficient outcomes that is consistent with the broader macro-economics in the JEN supply area. In terms of prudency, JEN considers the forecasting inputs (based on actual costs, independent forecasting economic indices and direct customer engagement) to determine a realistic expected expenditure required to achieve the capital expenditure objectives.
- The National Electricity Objective is concerned with promoting efficient investment for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply of electricity. JEN's methodology is aimed at providing a consistent, transparent and auditable approach underpinning the forecast capital expenditure that is required to meet the expected demand for customer connections and appropriately focused on investing to meet customers' needs. JEN considers its planning approach to customer connection works is consistent with JEN's network augmentation planning criteria, and is regarded as good practice.

6. APPENDIX A: MAJOR CUSTOMER NETWORK DEVELOPMENT PLANS

The purpose of this chapter is to explain the major customer development that requires network development plans to meet customers' needs.

[redacted]

6.5 YARRA BEND DEVELOPMENT STAGE 2 AND STAGE 5

Refer to ELE PL 0026 Fairfield Alphington Network Development Strategy.

7. APPENDIX B: AUSTRALIAN CONSTRUCTION MARKET REPORT

[redacted]

Jemena Electricity Networks (Vic) Ltd

Fairfield / Alphington

Network Development Strategy

ELE PL 0026

15 May 2019

An appropriate citation for this paper is:

Fairfield / Alphington
Our Ref: ELE PL 0026

Authorisation

Name	Job Title	Date	Signature
Reviewed by:			
	Senior Network Planning Engineer		
	Customer and System Planning Manager		
Approved by:			
General Manager	Asset Management		

History

Rev No	Date	Description of changes	Author
0.1	18/04/2019	Initial draft	Network Planning Engineer
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Owning Functional Area

Business Function Owner:	Asset Strategy Electrical

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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.
Continuous rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 344,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Probability of exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year:
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
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

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APF	Australian Paper Fairfield Zone Substation (decommissioned)
BTS	Brunswick Terminal Station
CB	Circuit Breaker
EP	East Preston Zone Substation (66 kV / 6.6 kV station)
EPN	East Preston Zone Substation (66 kV / 22 kV station)
EUE	Expected Unserved Energy
FF	Fairfield Zone Substation
HB	Heidelberg Zone Substation
JEN	Jemena Electricity Network
MD	Maximum Demand
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
POE	Probability of Exceedance
PTN	Preston Zone Substation
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
VCR	Value of Customer Reliability

OVERVIEW

Fairfield (FF) Zone Substation currently supplies over 6,500 customers at 6.6 kV in Fairfield and Alphington in the Jemena Electricity Network (JEN) supply area. This paper presents the emerging constraints in Fairfield and Alphington supplied by FF Zone Substation and the need for capacity augmentation in order to meet the forecast demand.

Identified Need

Demand at Jemena's FF Zone Substation supply area is expected to grow on average by 3.0% per annum during the next regulatory period 2021-26. The expected increase in demand is mainly driven by the current proposed residential and commercial developments at the former Amcor Paper Fairfield (APF) site, known as Yarrabend Development. The existing 22 kV sub transmission lines and feeders emanating FF Zone Substation are currently fully utilised and will not have sufficient capacity to meet the increasing demand.

Jemena's FF Zone Substation is supplied by three 22 kV sub transmission lines from AusNet's Brunswick Terminal Station (BTS). The BTS-FF sub transmission lines are forecasted to operate above its N-secure rating[1] in the coming summer 2019/20. By summer 2025/26, an outage on one of the BTS-FF 22 kV lines at the time of peak demand will overload the remaining BTS-FF 22 kV lines by up to 60%.

The 6.6 kV distribution feeders at FF Zone Substation are currently highly utilised and on the present forecasts, it is assessed that they will not have sufficient capacity to meet the projected needs of the customers in the area. The average utilisation of FF 6.6 kV feeders is projected to reach 145% under 10% Probability of Exceedance (POE) conditions by summer 2025/26.

Furthermore, presently there is very limited transfer points from FF to the only adjacent 6.6 kV network at East Preston (EP). Even with the existing transfer points, there isn't any emergency transfer capability available during peak loading period due the high loading of the existing EP 6.6 kV feeders. Jemena has already started works to maintain the reliability at FF Zone Substation. In the current regulatory period (2016-20), Jemena is replacing two of the three transformers at FF Zone Substation with larger 12/18 MVA 22/11-6.6 kV transformers due to the aging and deteriorated condition of the assets. The 22 kV bus at FF Zone Substation will also be converted to a ring bus arrangement as part of the transformer replacement project to make provision for future network capacity expansion at the sub transmission network level to meet on-going customer growth for the area.

Options Considered

In order to meet the increasing demand at Fairfield, the existing sub transmission lines and distribution feeders require augmentation. This paper looks at all credible options available to Jemena to provide a safe and reliable supply to the customers supplied from JEN FF Zone Substation.

A number of options to alleviate the emerging constraints in Fairfield and Alphington were investigated. These include:

- Option 1: Do nothing (Base Case);
- Option 2: Establish four new feeders (6.6 kV) from FF Zone Substation to Yarrabend Development and upgrade BTS-FF sub transmission line;
- Option 3: Establish three new feeders (11 kV) from Heidelberg (HB) Zone Substation to Yarrabend Development and upgrade TSTS-HB-Q-L sub transmission loop;

[1] JEN acceptable loading on the sub transmission line under system normal to maintain supply reliability during single contingency (N-1) condition.

- Option 4: Establish two new feeders (22 kV) from East Preston Zone Substation (EPN) to Yarrabend Development and upgrade TTS-EPN-PTN-TTS sub transmission loop;
- Option 5: Conversion of Fairfield Zone Substation from 6.6 kV to 11 kV and upgrade BTS-FF sub transmission line;
- Option 6: Establish a new 22 kV/6.6 kV zone substation at Yarrabend Development and install new BTS-Yarrabend sub transmission loop;
- Option 7: Battery Storage Solutions;
- Option 8: Demand management in first two years, then Option 2;
- Option 9: Embedded Generation.

Preferred Option

A summary of the market benefits analysis assessed for each credible option is presented in the Table OV-1 below.

Table OV-1: Summary of economic analysis results

No.	Option	Project cost (real $2019)	NPV of Net Market Benefits	Ranking
1	Do Nothing (base-case)	-	-$132.7M	8
2	Establish four new feeders (6.6 kV) from Fairfield Zone Substation to Yarrabend Development and upgrade BTS-FF sub transmission line	$21.9M	$114.8M	1
3	Establish three new feeders (11 kV) from Heidelberg Zone Substation to Yarrabend Development and upgrade TSTS-HB-Q-L sub transmission loop	$44.6M	$95.9M	5
4	Establish two new feeders (22 kV) from East Preston Zone Substation (EPN) to Yarrabend Development and upgrade TTS-EPN-PTN-TTS sub transmission loop	$24.2M	$109.4M	2
5	Conversion of Fairfield Zone Substation from 6.6 kV to 11 kV and upgrade BTS-FF sub transmission line	$35.6M	$100.5M	4
6	Establish a new 22 kV/6.6 kV zone substation at Yarrabend Development and install new BTS-Yarrabend sub transmission loop Battery Storage Solutions	$50.0M	$82.9M	7
7	Battery Storage Solutions	$47.7M	$89.2M	6
8	Demand management in first two years, then Option 2	$25.4M	$109.2M	3

In alignment with National Electricity Objective (NEO), the preferred and recommended strategy is the option that maximises the net economic benefits whilst maintaining a safe and reliable supply to customers. Option 2, establishing four new 6.6 kV feeders (rated to 11 kV) from FF Zone Substation and to upgrade the BTS-FF sub transmission loop, is shown to maximise the net economic benefit, and is therefore the preferred option for implementation.

The preferred Option 2 has a net market benefits of $114.8 million over a planning horizon of 10 years (2020 to 2029). The market benefits forecast to be delivered by the preferred solution are predominately driven by a reduction in the amount of expected unserved energy over the planning period.

1. INTRODUCTION

This section outlines the purpose of this development plan, provides an overview of the Fairfield and Alphington supply area, describes the general arrangement of Fairfield (FF) Zone Substation, and gives a brief overview of the network limitations in this area.

1.1 PURPOSE

The proposed development plan is consistent with JEN's long term asset management objectives which require JEN to comply with all regulatory obligations. In this case, the objective of this development strategy is to meet the needs of customer demand in Fairfield and Alphington at the least cost to customers.

1.2 CURRENT STATE

JEN customers in Fairfield and Alphington are currently being supplied by six 6.6 kV feeders from Fairfield (FF) Zone Substation. The substation also supplies six of CitiPower 6.6 kV feeders. The area is confined by 11 kV feeders of Heidelberg (HB) Zone Substation in the east, Yarra River (natural boundary) in the south and CitiPower's network in the west and north. Very limited backup capability is provided by two 6.6 kV feeders (EP34 and EP36) from East Preston (EP) Zone Substation in the north east and during peak loading times, there is no backup at all from EP feeders. Figure 1–1 and Figure 1–2 show the geographic supply areas of FF Zone Substation, including its 6.6 kV feeders (highlighted in green in Figure 1–1) and its surrounding HB and EP Zone Substations.

Sub transmission network

Electricity supply to FF Zone Substation is provided by three 22kV sub-transmission lines (BTS-FF181, BTS-FF 184 and BTS-FF 188) supplied from Ausnet Services' Brunswick Terminal Station (BTS), as shown in Figure 1-4. Two of these three circuits are constructed on a single pole line from BTS to FF Zone Substation.

The existing 22 kV sub transmission lines are forecasted to be overloaded due to increase in demand around Fairfield supply area. Based on the current forecast, the existing sub transmission loop are exposed to the following risks:

- Loss of any one of the 22 kV lines from BTS will lead to an overload on the remaining two lines, well above their thermal capacity; and
- Loss of two sub-transmission lines under the following single contingency events:
  - Outage of 1,760 m long BTS-FF184 and BTS-FF188 double circuit pole line; and
  - Outage of 700 m long BTS-FF181 and BTS-FF184 double circuit pole line.

As part of this strategy paper, the options evaluated will also consider the above sub transmission network risks.

Refer to Section 1.4 for BTS-FF sub transmission lines load forecast.

Zone substation

FF Zone Substation currently has three 10/13.5 MVA 22/6.6 kV transformers, one 4.35 MVAr capacitor bank, a 2.4 Ω neutral earthing resistor and twelve 6.6 kV feeder circuit breakers. Being very close to the CitiPower boundary, six 6.6 kV feeders from FF Zone Substation cross the boundary line and supply CitiPower customers. The remaining six feeders supply approximately 6,400 customers in JEN territory.

The existing FF Zone Substation transformers were manufactured in 1955 and due to their age and condition, as confirmed by paper samples taken from the winding leads of the No.1, No.2 and No.3 transformers in 2013 and 2014, will require replacement to maintain acceptable levels of supply reliability.

Three key options were considered to manage the risk associated with the aging transformers at FF:

- Option 1: Replace the existing three 10/13.5 MVA transformers with three new 12/18 MVA transformers.
- Option 2: Replace two of the existing three 10/13.5 MVA transformers with two new 12/18 MVA transformers and keep the third 10/13.5 MVA transformer as a hot spare.
- Option 3: Replace the existing three 10/13.5 MVA transformers with two new 28.5 MVA transformers.

Jemena has identified that Option 2 maximises net market benefits of the project whilst achieving an appropriate level of environmental, safety and operational risk and is therefore the preferred option for replacement of the aging transformers. This project is currently under construction and is due for completion by mid-2020.

On completion of the FF transformer replacement project, FF zone substation will have a 22 kV ring bus arrangement, two 12/18MVA 22/6.6kV transformers, one hot stand-by 10/13.5MVA 22/6.6kV transformer, one 4.35 MVAr capacitor bank, a 2.4 Ω neutral earthing resistor and twelve 6.6 kV feeder circuit breakers. Six 6.6 kV feeders from FF Zone Substation will continue to supply CitiPower customers, with the remaining six feeders supplying Jemena's customers in JEN supply area.

Figure 1–3 presents a single line diagram of FF Zone Substation after the FF transformer replacement project.

Refer to Section 1.5 for FF Zone Substation load forecast.

HV Feeders

The feeders supplying JEN customers in the Fairfield and surrounding areas are currently highly utilised. Following an outage there is insufficient transfer capacity available to meet forecast demand. Additionally, with the ongoing conversion of its neighbouring East Preston zone substation, from 6.6 kV to 22 kV by 2024, the FF supply area will become an isolated 6.6 kV network.

Refer to Section 1.6 for FF HV feeders forecast.

Figure 1–1: Supply area of Fairfield Zone Substation shown by its 6.6 kV feeders

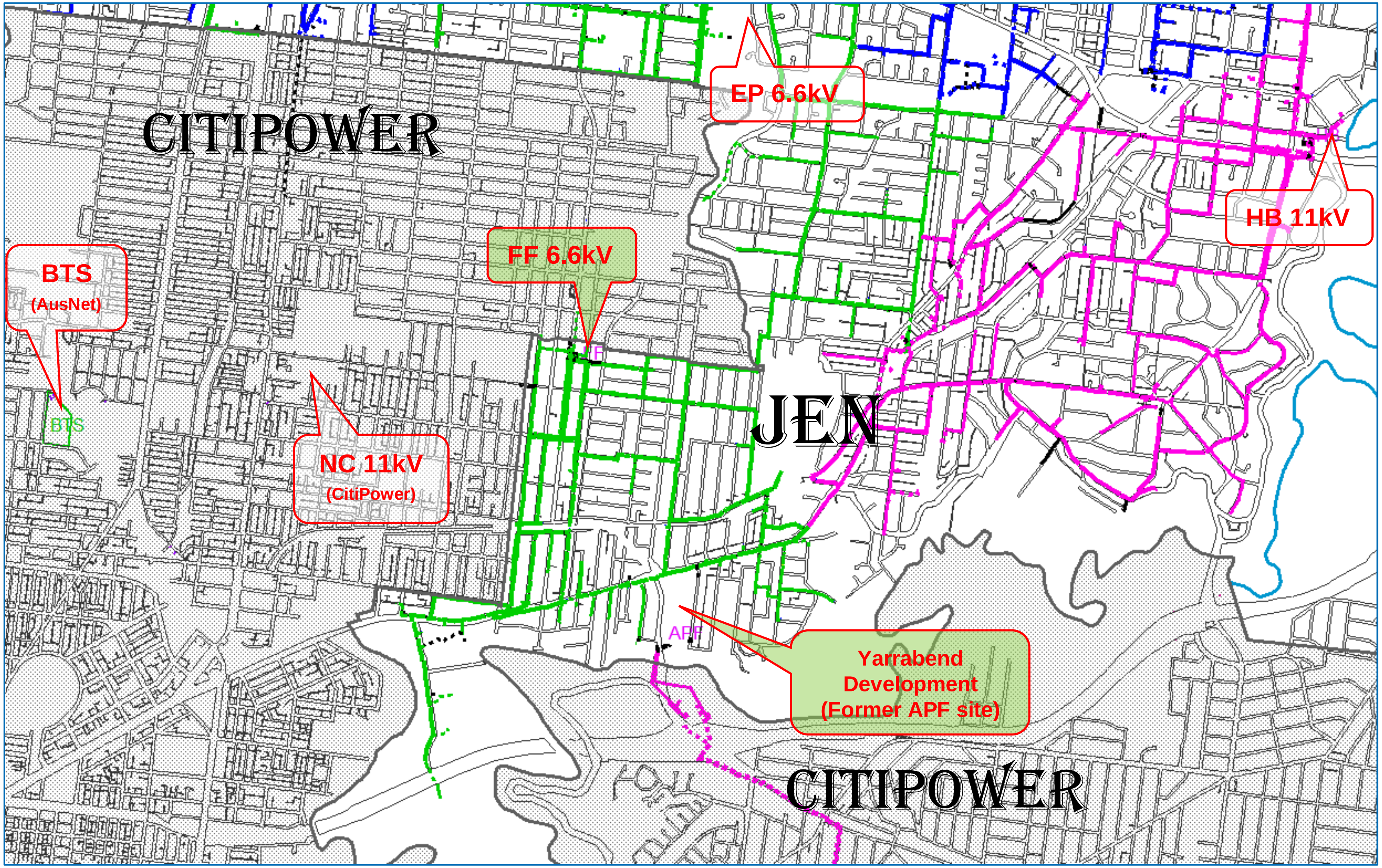


Figure 1–2: Supply areas of Fairfield Zone Substation and surrounding zone substations

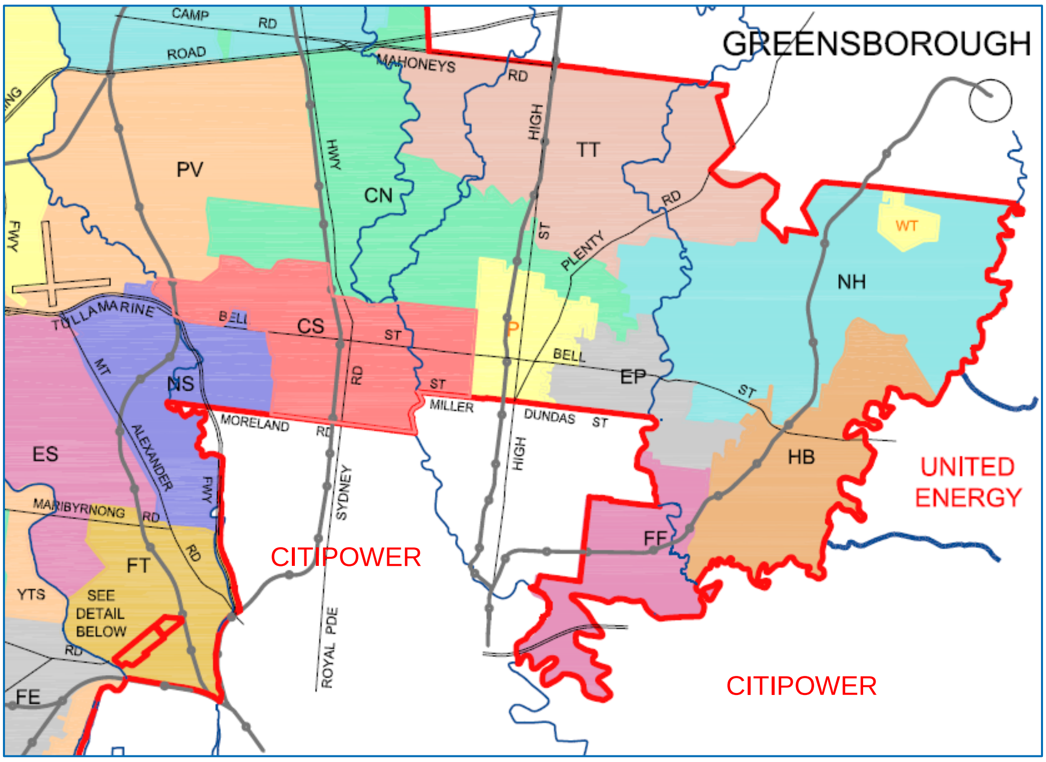
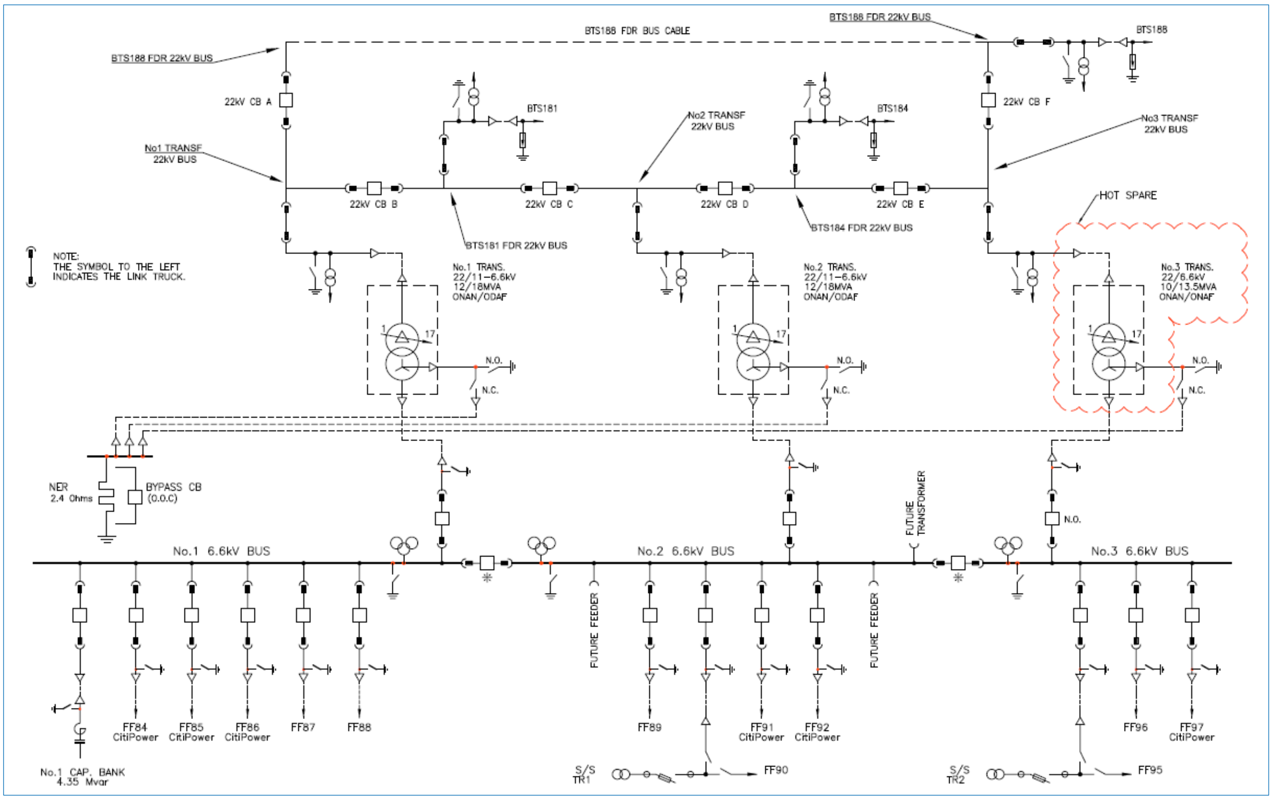


Figure 1–3: Fairfield Zone Substation Single Line Diagram



1.3 NEW LOADS

The demand forecast is an essential tool to identify the emerging network constraints and the need for reinforcement. The analyses presented in this document are based on the maximum demand forecasts prepared in 2019[2]. Based on the 2019 JEN demand forecast, maximum demand at Fairfield zone substation is forecast to grow by 3.0% over the next 5 years. This is mainly driven by the Yarrabend Development to residential and commercial mixed use developments. New developments at Yarrabend Development site has plans to include over 1,900 new residential dwellings (mixture of apartments and townhouses) together with major multi-level commercial and retail facilities. [redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Based on the customer's projected development and forecast, Yarrabend Development will add over [redacted] This will significantly increase the zone substation and sub transmission loop loading. However, considering the existing economic condition, Jemena has used a more conservative and realistic approach in our load demand forecast and expects only 5.3 MVA load uptake by 2023 and a total of 10.8 MVA by 2026. Table 1-2 shows the Jemena expected load growth at Yarrabend Development.

Table 1-2: Projected Jemena load forecast (50%PoE) for Yarrabend Development

Target date of new loads	Additional new load (kVA)	Total new load (kVA)
2019 (existing load)	460	460
2020	137	597
2021	932	1,529
2022	1,788	3,317
2023	1,935	5,252
2024	1,517	6,769
2025	1,963	8,732
2026	2,107	10,839

The new developments currently have an initial load uptake of 460 kVA in 2019. The existing 22 kV sub-transmission lines and 6.6 kV feeders will not have sufficient capacity to support increasing demand at FF Zone Substation supply area.

[2] "*RP-NCPA-NWA-2019-170 JEN Load Demand Forecast*", December 2019.

- The existing feeders (FF95 and FF96) supplying the area near the new development are already heavily loaded and FF95 is forecast to be well overloaded by summer 2020/21.
- The sub-transmission lines will be operating above its N-secure rating by summer 2019/20.

Therefore, there is insufficient spare capacity on existing sub transmission lines and FF feeders, to support the new developments at Yarrabend Development. Augmentation works will be required within the 2021-2026 regulatory period to address the risk of overloaded feeders and sub transmission lines to meet customer demand for the area. Section 1.4 presents further information on the sub transmission lines.

1.4 SUB-TRANSMISSION LINE UTILISATION AND FORECAST

Electricity supply to FF Zone Substation is provided by three 22 kV sub-transmission lines (BTS-FF181, BTS-FF 184 and BTS-FF 188) supplied from Ausnet Services' Brunswick Terminal Station (BTS) as shown in Figure 1-4.

Figure 1–4: Geographic map of the BTS-FF 22 kV sub-transmission lines

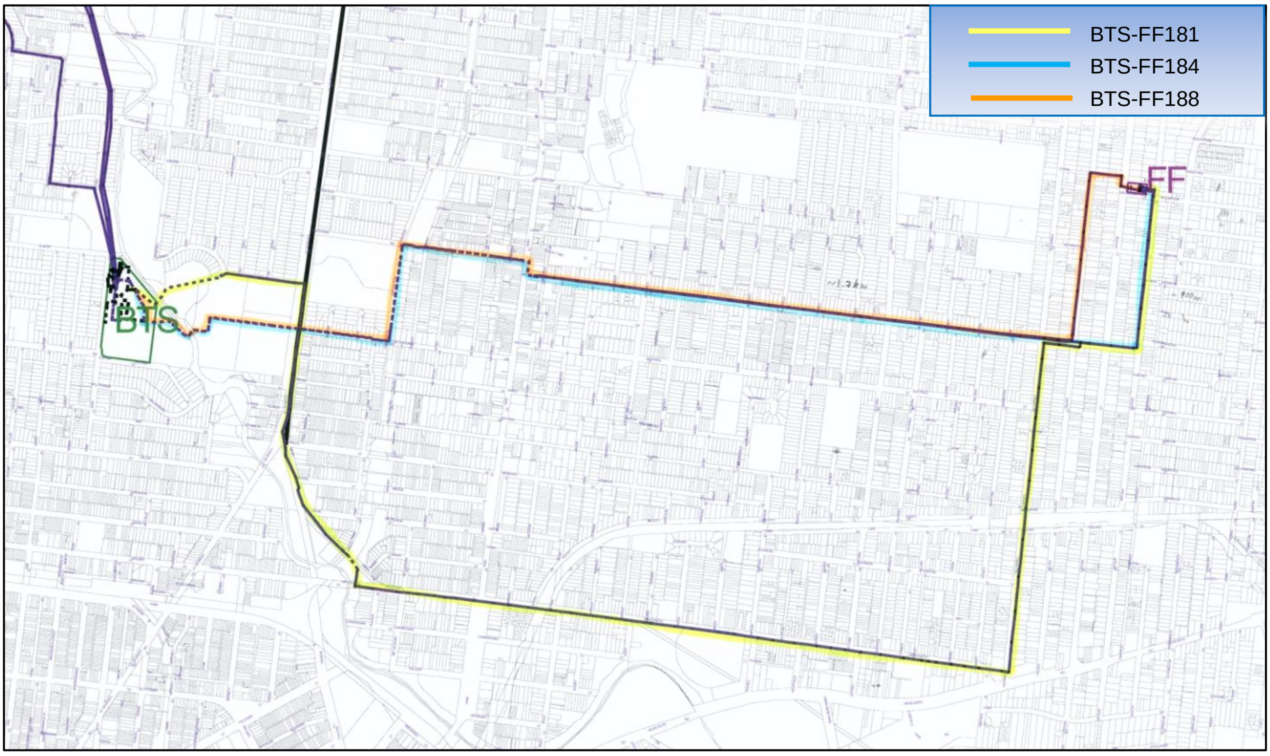


Table 1-3 shows the current rating of the sub-transmission lines.

Table 1-3: BTS-FF Sub Transmission Line Rating

	Summer	Winter
BTS-FF 181	11.4 MVA	13.0 MVA
BTS-FF 184	13.1 MVA	13.7 MVA
BTS-FF 188	13.1 MVA	13.7 MVA

Based on the load flow analysis carried out using PSSE software, for an outage of one of the BTS-FF 22kV lines at a time of peak demand in summer 2020/21, the remaining BTS-FF 22kV lines is forecast to be overloaded by up to 34% (representing up to 4.4 MVA of load at risk and equivalent to approximately 1,200 customers at risk of being load shed), and by summer 2025/26 this thermal overloaded condition is forecast to exceed 60% of the line rating (representing up to 7.8 MVA of load at risk and equivalent to approximately 2,180 customers at risk of being load shed). Overloading 22 kV lines beyond their thermal rating will also cause overhead conductors to sag excessively and will cause long term damage to assets. Excessive conductor sagging has a risk of the statutory line clearance limits being infringed. The substandard clearance could lead to accidents (such as vehicles contacting overhead conductors and sagged 22 kV lines being in contact with subsidiary 6.6 kV circuits). Table 1-4 and Table 1-5 show the utilisation of the 22 kV lines under N and N-1 condition for the forward planning period.

Table 1-4: Sub transmission line utilisation under system normal (N)

	2021	2022	2023	2024	2025	2026
BTS-FF 181	57%	58%	61%	61%	64%	67%
BTS-FF 184	79%	79%	82%	85%	88%	92%
BTS-FF 188	81%	82%	85%	87%	90%	94%

Table 1-5: Sub transmission line utilisation under outage condition (N-1)

	2021	2022	2023	2024	2025	2026
BTS-FF 181	96%	100%	103%	106%	111%	115%
BTS-FF 184	132%	137%	140%	145%	153%	158%
BTS-FF 188	134%	138%	142%	147%	154%	160%

Further to this risk, due to the double circuit line construction for the sub-transmission lines as shown in Figure 1–4, there is a likely chance of losing two 22 kV sub transmission lines during a single contingency event such as vehicle accidentally running into the pole. This could potentially lead to an outage of the whole FF Zone Substation due to subsequent overload on the remaining line. As FF Zone Substation will be operating as an island post the conversion of EP zone substation to 22 kV, this will affect the supply reliability for customers serviced from FF Zone Substation.

1.5 ZONE SUBSTATION UTILISATION AND FORECAST

As discussed in Section 1.2, FF Zone Substation replacement project will be completed in 2020. On completion of this project, FF Zone Substation will have two new 12/18 MVA 22/11-6.6 kV transformer and one existing 10/13.5 MVA 22/6.6 kV transformer operating as a hot stand-by. As part of the transformer replacement project, the station will also be converted to a fully switched station with a 22 kV ring bus arrangement. Establishing a 22 kV ring bus will ensure a secure sub-transmission supply to the station during the transformer replacement works.

Table 1-6 shows the rating of FF zone substation after the completion of the transformer replacement project.

Table 1-6: FF Zone Substation Rating

	Summer	Winter
N Rating (MVA)	36.0	36.0

	Summer	Winter
N-1 Rating (MVA)	31.5	31.5

Table 1-6 shows the maximum demand forecast for FF zone substation for the forward planning period.

Table 1-7: FF Zone Substation Demand Forecast

	2021	2022	2023	2024	2025	2026
Summer – 10%POE (MVA)	26.6	27.5	28.2	29.0	30.2	31.4
Summer – 50%POE (MVA)	24.0	24.8	25.7	26.3	27.3	28.5

Based on the above forecast, there is sufficient capacity at the zone substation to supply the area in the forward planning period.

1.6 FEEDER UTILISATION AND FORECAST

Table 1-8 and
Table 1-9 below show the projected summer utilisation of FF feeders over the forward planning period under 10% POE and 50% POE conditions. Based on the current network configuration, feeders FF-095 and FF-087, supplying the Yarrabend Development, are projected to be severely overloaded in the forward planning period.

Table 1-8: Projected summer utilisation of FF feeders under 50% POE

Feeder	Rating (MVA)	2020	2021	2022	2023	2024	2025	2026
FF087	3.3	58%	64%	71%	79%	84%	89%	96%
FF088	3.3	66%	65%	64%	63%	63%	63%	63%
FF089	3.3	69%	69%	68%	67%	67%	66%	66%
FF090	3.3	81%	83%	84%	83%	82%	82%	82%
FF095	3.3	86%	112%	163%	217%	258%	313%	374%
FF096	3.3	87%	86%	86%	85%	85%	85%	85%

Table 1-9: Projected summer loading and utilisation of FF feeders under 10% POE

Feeder	Rating (MVA)	2020	2021	2022	2023	2024	2025	2026
FF087	3.3	65%	71%	78%	86%	92%	98%	105%
FF088	3.3	73%	72%	71%	70%	69%	69%	69%
FF089	3.3	75%	74%	73%	72%	71%	71%	71%
FF090	3.3	90%	93%	93%	92%	91%	91%	91%
FF095	3.3	99%	129%	188%	247%	296%	360%	429%

Feeder	Rating (MVA)	2020	2021	2022	2023	2024	2025	2026
FF096	3.3	98%	97%	96%	95%	95%	95%	95%

2. IDENTIFIED NEED

The sub transmission lines supplying Fairfield zone substation and the feeders will not have enough capacity to supply the new development at Yarrabend Development. Major risks associated with operating assets above rating are:

- Increased risk of breaching statutory clearances (green book) on bare overhead conductors;
- Increased risk of failure of equipment (e.g. cables, joints, etc.) when equipment is pushed to operate well above its design limits; and
- Inability to restore all lost supplies in the event of a feeder and sub transmission line outage.

Furthermore, the supply area of FF Zone Substation will become an isolated 6.6 kV network within the next five years (once its neighbouring EP zone substation is all converted to 22 kV). Once East Preston area have been converted to 22 kV, there will be no emergency transfer capability away from FF Zone Substation to restore supply in the event of a major outage at either FF Zone Substation or its upstream sub-transmission network. Therefore any proposed works in the area over the next forward planning period will have to take this into consideration and ensure the project aligns with the long-term area needs and requirements.

3. OPTIONS

The following credible options to alleviate the emerging constraints in Fairfield and Alphington were investigated:

- Option 1: Do nothing (Base Case);
- Option 2: Establish four new feeders (6.6 kV) from Fairfield Zone Substation to Yarrabend Development and upgrade BTS-FF sub transmission line;
- Option 3: Establish three new feeders (11 kV) from Heidelberg Zone Substation to Yarrabend Development and upgrade TSTS-HB-Q-L sub transmission loop;
- Option 4: Establish two new feeders (22 kV) from East Preston Zone Substation (EPN) to Yarrabend Development and upgrade TTS-EPN-PTN-TTS sub transmission loop;
- Option 5: Conversion of Fairfield Zone Substation from 6.6 kV to 11 kV and upgrade BTS-FF sub transmission line;
- Option 6: Establish a new 22 kV/6.6 kV zone substation at Yarrabend Development and install new BTS-Yarrabend sub transmission loop;
- Option 7: Battery Storage Solutions;
- Option 8: Demand management in first two years, then Option 2;
- Option 9: Embedded Generation.

3.1 STUDY ASSUMPTIONS

In evaluating net economic benefits, the following assumptions are used to calculate the annualised value of expected unserved energy (EUE) for all the options analysed in this paper:

- Value of Customer Reliability (VCR) of $41,331 per MWh[3];
- Average feeder outage rate is calculated based on Jemena historic data;
- Average supply restoration time for underground assets is 8 hours and overhead assets is 4 hours,
- Load duration curve = (MW) readings, from 1 April 2017 to 31 March 2018 inclusive, scaled to match projected sum of feeder peak demands.
- It is assumed that 6.6 kV feeder FF-093 will be commissioned by November 2020.
- Feeder expected unserved energy at risk have only been calculated for N condition.

[3] Refer Network Augmentation Planning Criteria - JEN PR 0007, for details.

3.2 OPTION 1: DO NOTHING (BASE CASE)

The “Do Nothing” option presents the forecast energy at risk assuming none of the identified network augmentation options are implemented. It is used as a reference or the “Base Case”, against which all of the credible options are compared and shows the comparative benefits of each credible option.

The risks associated with the “Do Nothing” option are:

- Increased risk of breaching statutory clearances (green book) on bare overhead conductors;
- Increased risk of failure of equipment (e.g. cables, joints, etc.) when equipment is pushed to operate well above its design limits;
- Inability to restore all lost supplies in the event of loss of a FF feeder or sub-transmission line during peak demand period;
- Deterioration of supply reliability due to capacity shortfall; and
- Intangible costs to Jemena arising from negative publicity generated due to longer than expected supply restoration time.

Table 3-1 and Table 3-2 summarises the annualised value of the expected unserved energy (EUE) for the FF feeders (FF-96, FF-95 and FF-96) and sub-transmission lines for the base case over the next ten year (2020-2029).

The value of expected unserved energy (EUE) is calculated based on the assumptions listed in Section 3.1.

Table 3-1: Value of Expected Unserved Energy (EUE) - FF Feeders

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
50PoE Summer Forecast (MVA)	6.3	7.0	8.8	10.7	12.2	14.2	16.3	16.8	17.4	18.0
10PoE Summer Forecast (MVA)	7.1	7.9	9.7	11.6	13.2	15.3	17.5	18.1	18.7	19.3
Weighted average EUSE (MWh)	0	0	0	2	29	159	980	1,090	1,224	1,396
Weighted average EUSE ($M)	$-	$-	$-	$0.08	$1.19	$6.57	$40.52	$45.06	$50.61	$57.72

Table 3-2: Value of Expected Unserved Energy (EUE) – FF Sub Transmission Lines

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
FF 50PoE Summer Forecast (MVA)	23.6	24.0	24.8	25.7	26.3	27.3	28.5	29.5	29.7	29.8
FF 10PoE Summer Forecast (MVA)	26.3	26.6	27.5	28.2	29.0	30.2	31.4	32.6	32.7	32.9
Weighted average EUSE (MWh)	6.0	6.6	8.0	9.6	11.2	13.8	17.6	22.2	22.5	23.1

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.46	$0.57	$0.73	$0.92	$0.93	$0.95

3.3 OPTION 2: ESTABLISH FOUR NEW 6.6 KV FEEDERS (RATED TO 11 KV) FROM FF ZONE SUBSTATION AND UPGRADE BTS-FF SUB TRANSMISSION LINES

This option looks at upgrading the BTS-FF sub transmission lines and to run four new 6.6 kV feeders rated at 11 kV from FF Zone Substation to supply the new load proposed at Yarrabend Development.

3.3.1 FF SUB TRANSMISSION LINES WORK

FF sub transmission works involves running a new 22 kV underground cable from BTS to FF Zone Substation. Given that, FF Zone Substation is located in a rather densely populated area, it is assumed that the new BTS-FF 22 kV line will have to be fully undergrounded. The BTS terminal station does not have any spare 22 kV circuit breaker. Hence, the 22 kV bus at BTS terminal station will have to be extended.

The existing sub transmission lines have sections of the route running two 22 kV circuits on the same pole line (double circuit pole). Single contingency event on this section, could take out both 22 kV lines out of service, which could result in a loss of supply to FF Zone Substation. This proposed option to have four 22 kV lines from BTS to FF will eliminate this risk.

The proposed scope of works include:

- Extend existing Bus 1 and 3 and install a new CB at Bus-1 and a new CB at Bus-3 to have double switched arrangement at BTS terminal station to establish a new sub-transmission feeder exit;
- Supply and install approximately 4.0 km of new 300mm^2 AL XLPE underground cable from BTS feeder CB to the new 22 kV pole within FF Zone Substation.

The total cost to run a new sub transmission line from BTS to FF is estimated to be $6,506k in real 2019 dollars. On completion of the proposed project, there will be no load at risk on the FF sub transmission lines under N and N-1 conditions for the next ten years.

3.3.2 FF FEEDER UPGRADE WORK

Feeder works at FF zone substation involves, running four new 6.6 kV feeders[4] rated to 11kV (in line with the long term objective for the area) from FF Zone Substation to Yarrabend Development. The timing of the new feeders will be based upon the new load uptake at Yarrabend Development. Based on the current forecast, two new feeders will be required in the next regulatory period (2021-26), with the next two feeders required after 2026.

FF Zone Substation currently has two spare panels (without interrupters) for future feeder CBs; hence its 6.6kV switchboard would need to be extended to install the proposed feeders. Given that FF Zone Substation is located in a rather densely populated area, underground cable is likely to be the only acceptable option for new feeders in the area.

The scope of works, estimated cost and proposed timing for the new feeders are as follow:

[4] Additional new feeders will be rated at 375 A (4.3 MVA at 6.6 kV), as per the present standard.

- New 6.6 kV FF94 feeder (heading south):
  - Install a new 11kV feeder CB at future feeder position on Bus No.2 and connect existing feeder FF87 exit cable. Connect existing feeder CB at Bus No.1 from feeder FF87 position to new FF94 feeder exit cable as required to complete final bus layout.
  - Install approximately 2,500 metres of new 3C.300mm2 AL XLPE underground cable (and 3 spare 150mm HV conduits) from the existing 6.6kV CB at feeder FF87 position on Bus No.1 for feeder FF94 to the new kiosk substation as part of Stage 2 development. The proposed route for the new cable and 3 spare 150mm HV conduits are along McGregor St, Sparks Ave, Chingford St, Fulham Rd, Smith St, Keith St, Parklands Ave, Naroon Rd, Wingrove St, Lowther St, Heidelberg Rd and Latrobe Ave within Yarra Bend Development. The proposed conduits shall be installed with appropriate separation to minimise de-rating feeder underground cable.
  - The estimated cost for this new feeder is $3,785k[5] (real $2019) and is required by November 2022.
- New 6.6 kV FF98 feeder (heading south):
  - Extend the 6.6kV No. 3 bus at FF Zone Substation by installing an additional panel and a new 6.6 kV feeder CB (rated to 11kV).
  - Install approximately 2,200 metres of new 3C.300mm2 AL XLPE underground cable (and 3 spare 150mm HV conduits) from the new 6.6kV feeder FF98 CB to the new indoor substation as part of Stage 5 development. The proposed route for the new cable and 3 spare 150mm HV conduits are along McGregor St, Sparks Ave, Rayment St, Fulham Rd, new road within Yarra Bend Development. The proposed conduits shall have appropriate separation to minimise de-rating feeder underground cable.
  - The estimated cost for this new feeder is $5,091k[6] (real $2019) and is required by November 2024.
- New 6.6 kV FF99 feeder (heading south):
  - Install a new 6.6kV feeder CB (rated to 11 kV) in the spare panel on FF 6.6 kV extended Bus No.3.
  - Install approximately 2,300 metres of new 3C.300mm2 AL XLPE underground cable (and 1 spare 150mm HV conduits) from the existing 6.6kV feeder FF99 CB to new kiosk substation as part of Stage 13B development. The proposed route for the new cable is along McGregor St, Arthur St, Rayment St, Perry St, Wingrove Ave, Grange Rd, Chandler Hwy and new road within Yarra Bend Development. The proposed conduits shall be installed with appropriate separation to minimise de-rating feeder underground cable.
  - The estimated cost for this new feeder is $3,377k[7] (real $2019) and is required by November 2027.
- New 6.6 kV FF100 feeder (heading south):
  - Install a new 6.6kV feeder CB (rated to 11 kV) in the spare panel on FF 6.6 kV extended Bus No.3.

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[5] This cost includes HV feeder works only, and excludes distribution substations and LV network reticulation within Yarrabend Development which is a common cost to all credible options considered.

[6] This cost includes HV feeder works only, and excludes distribution substations and LV network reticulation within Yarrabend Development which is a common cost to all credible options considered.

[7] This cost includes HV feeder works only, and excludes distribution substations and LV network reticulation within Yarrabend Development which is a common cost to all credible options considered.

- Install approximately 2,500 metres of new 3C.300mm2 AL XLPE underground cable via already installed 2 spare 150mm HV conduits as part of FF-94 feeder works from the existing 6.6kV feeder FF99 CB to the new kiosk substation as part of Stage 8A development. The proposed route for the new cable is along McGregor St, Sparks Ave, Chingford St, Fulham Rd, Smith St, Keith St, Parklands Ave, Naroon Rd, Wingrove St, Lowther St, Heidelberg Rd and Latrobe Ave within Yarra Bend Development.
- The estimated cost for this new feeder is $3,127k[8] (real $2019) and is required by November 2029.

The total cost of extending the existing FF 6.6 kV switchboard (rated at 11 kV) and establishing four new 6.6 kV feeders (rated at 11 kV) is estimated to be $15,381k (real $2019). The proposed after HV diagram for the new 6.6 kV feeder (rated to 11kV) is provided in Appendix A. On completion of the proposed project, there will be no load at risk under N and N-1 conditions on the FF feeders.

3.3.3 DELIVERABILITY RISK

Fairfield Zone Substation is the closest JEN Zone Substation to the Yarrabend development. JEN has reduced the deliverability risk by undergrounding all four feeders from FF Zone Substation and the Sub Transmission line from BTS Terminals Station. The proposed routes for the new feeders and sub transmission line has been selected to avoid major roads or intersections. However, sections of the sub transmission line is running through CitiPower distribution area and JEN has limited information about the CitiPower assets along the proposed route. This could impact the proposed route of the sub transmission line. However, it is considered a low risk as FF Zone Substation is located close to BTS terminals station minimising the route length. Besides this, Jemena has already undergrounded sections of the existing sub transmission line within this area.

Based on the above assessment Jemena has given a low risk profile for this option.

3.3.4 OPTION 2 - ECONOMIC ANALYSIS

The total project cost of upgrading the sub transmission line and to install four new feeders for the Yarrabend development is estimated to be $21.9 million (real $2019 with overheads). Table 3-3 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-3: Value of EUE and Market Benefits (Option 2)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	6.021	6.641	7.981	9.635	0.001	0.001	0.003	0.006	0.006	0.007
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EUSE-Base Case ($M)	$0.25	$0.27	$0.33	$0.48	$1.65	$7.14	$41.24	45.98	$51.54	$58.67
Market Benefits ($M)	$-	$-	$-	$0.08	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-4 shows that this option is economically viable.

8 This cost includes HV feeder works only, and excludes distribution substations and LV network reticulation within Yarrabend Development which is a common cost to all credible options considered.

Table 3-4: Economic analysis of Option 2

	Total
Present Value of Costs	$16.8M
Present Value of Benefits	$131.6M
NPV – Net market benefit	$114.8M

3.4 OPTION 3: ESTABLISH THREE NEW FEEDERS FROM HEIDELBERG ZONE SUBSTATION AND UPGRADE TSTS-HB-Q-L-TSTS SUB TRANSMISSION LOOP

This option looks at supplying the Yarrabend Development from Jemena Heidelberg (HB) Zone Substation by running three new 11 kV feeders from HB Zone Substation. The sub transmission loop supplying Jemena HB Zone Substation is shared between CitiPower and Jemena and is already operating well above its rating under single contingency condition. Hence, the 66 kV loop needs to be upgraded before adding major load to Jemena HB Zone Substation.

3.4.1 TSTS-HB-Q-L SUB TRANSMISSION LINES WORK

The existing sub transmission loop TSTS-HB-Q-L is fully rated, hence to increase the capacity on the loop a third 66 kV line needs to be installed from Templestowe Terminal Station (TSTS). The existing 66 kV sub transmission lines are installed on the AusNet 220 kV transmission towers. The sub transmission loop is running outside Jemena distribution boundary, hence Jemena does not have any easement available to run the new 66 kV line from TSTS terminal station.

Given that Templestowe and Heidelberg areas are densely populated and is outside the Jemena distribution network, it is assumed that undergrounding the sub transmission line might be the only acceptable solution.

The proposed scope of works include:

- Installing 1 x 66 kV bus-tie circuit breaker and 2 x 66 kV line circuit breakers at HB Zone Substation.
- Run approximately 9,500m of new underground 3 x 1C 1200mm^2 AL XLPE 66kV cable in conduit from TSTS terminal station to HB Zone Substation.

The total cost to run a new sub transmission line from TSTS to HB Zone Substation is estimated to be $26,750k ($2019).

Table 3-5 shows the forecast risk on the TSTS-HB-Q-L loop with the proposed Yarrabend load supplied from HB Zone Substation.

Table 3-5: Value of Expected Unserved Energy (EUE) – TSTS-HB-Q-L Sub Transmission Loop

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EUSE at 50% POE (MWh)	0.0	0.1	0.2	0.3	0.5	2.0	14.3	17.6	22.3	30.7
EUSE at 10% POE (MWh)	0.2	4.8	20.7	47.9	56.7	98.6	181.9	226.3	274.6	257.8

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	0.1	1.5	6.3	14.6	17.3	31.0	64.6	80.2	98.0	98.8
Weighted average EUSE ($M)	$0.00	$0.06	$0.26	$0.60	$0.72	$1.28	$2.67	$3.32	$4.05	$4.08

On completion of the proposed project, there will be no load at risk under N and N-1 conditions on the TSTS-HB-Q-L sub transmission lines.

3.4.2 HB ZONE SUBSTATION WORKS

HB Zone Substation has two 20/33 MVA 66/11 kV transformers supplying the three 22 kV buses. Table 3-6 shows the current rating of the HB Zone Substation.

Table 3-6: HB Zone Substation Rating

	Summer	Winter
N Rating	45.0 MVA	45.0 MVA
N-1 Rating	29.2 MVA	35.6 MVA

Table 3-7 shows the loading on HB zone substation with the future Yarrabend Development load.

Table 3-7: HB Zone Substation Demand Forecast

	2019 (Actual)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Summer – 10 POE (MVA)	27.4	29.6	30.7	33.1	35.2	36.8	38.8	40.8	41.2	41.8	42.4
Summer – 50 POE (MVA)	27.4	26.6	27.8	30.1	32.4	33.9	35.8	37.9	38.4	38.9	39.6

Based on the current forecast, there is sufficient capacity under N condition at the zone substation to supply future demand, hence for this analysis it is assumed no work is required at the zone substation.

3.4.3 HB FEEDER UPGRADE WORK

Based on the current configuration, spare circuit breakers are available from each of the 11 kV bus to run the new feeders to Yarrabend Development. The current plan is to install two new 11 kV feeders from HB zone substation within the next regulatory period (2021-26). The third feeder to Yarrabend Development will be installed in the following regulatory period (2026-30). Given that, Heidelberg area is well developed and is densely populated, Jemena has assumed that all three feeders coming from HB Zone Substation has to be fully undergrounded to Yarrabend Development.

The scope of works, estimated cost and proposed timing for the new feeders are as follow:

- New 11 kV HB-013 feeder:
    - Use the existing spare CB on the No.1 11 kV bus to establish the new feeder.

    - Install approximately 5,500m of new 300mm2 AL XLPE underground cable (and 2 spare 150mm HV conduits) from the existing feeder HB-013 CB to a new kiosk substation inside Yarrabend Development. The proposed route of the new feeder is along Heidelberg Rd, Lower Heidelberg Road and new road within Yarrabend Development to form the new feeder. The proposed conduits shall be installed with appropriate separation to minimise de-rating feeder underground cable.
    - The estimated cost for this new feeder is $6,875k ($2019) and is required by November 2022.
- Install a new 11 kV HB-025 feeder:
    - Use the existing spare CB on the No.2 11 kV bus to establish the new feeder.
    - Install approximately 5,200 m of new 300mm^2 Al XLPE cable from the existing feeder HB-025 CB to a new kiosk substation inside Yarrabend Development. The proposed route of the new feeder is along Heidelberg Rd, The Eyrie, Lockley Rd, Toora St, Young St, Clarence St, Waterdale Rd, Lower Heidelberg Rd and new road within Yarrabend Development.
    - The estimated cost for this new feeder is $5,500k ($2019) and is required by November 2022.
- Install a new 11 kV HB-033 feeder:
    - Use the existing spare CB on the No.3 11 kV bus to establish the new feeder.
    - Install approximately 6,800 m of new 300 mm^2 Al XLPE cable from the existing feeder HB-033 CB to a new kiosk substation inside Yarrabend Development. The proposed route for the new feeder is along The Boulevard, along Heidelberg Rd and new road within Yarrabend Development.
    - The estimated cost for this new feeder is $8,500k ($2019) and is required by November 2029.

The total cost for establishing three new 11 kV feeders is estimated to be $20,875k ($2019). Since we are resolving the overloading issue on FF feeders by running the new feeders from HB Zone Substation, the net market benefits for the new HB feeders is equivalent to the value of EUE for the FF feeder base-case scenario presented in Table 3-1.On completion of the proposed project, there will be no load at risk on FF and HB feeders under system normal condition over the next 10 years with the new loads from Yarrabend development.

3.4.4 DELIVERABILITY RISK

In order to minimise the risk we have assumed that all three feeders from HB Zone Substation and the new 66 kV Sub Transmission line from TSTS terminal station will be fully undergrounded. However, the below identified constraints could impact the deliverability of this option.

- Based on the proposed route all three feeders from HB Zone Substation have to cross the Darebin Creek to supply the Yarrabend development. This could add significant risk to the project cost and delivery timeframe.
- The proposed scope involves work around busier Heidelberg and Lower Heidelberg road. Based on Vic Road requirement more night work or weekend work might be required which could impact the project cost and delivery timeframe.
- The proposed route to run the new Sub Transmission line from TSTS is outside the JEN distribution boundary and the route length is approximately 10km. JEN has limited information about other DB assets along the proposed route.
- JEN current ultimate system design for HB Zone Substation does not propose a third 66 kV line to the Zone Substation. This could impact the cost of the project as JEN might be required to relocate assets within the Zone Substation to make space for the new 66 kV line and circuit breakers.

Based on the above assessment Jemena has given a medium deliverability risk profile for this option.

3.4.5 OPTION 3 - ECONOMIC ANALYSIS

The total project cost of upgrading the sub transmission line and to install three new feeders for the Yarrabend Development is estimated to be $44,625k (real $2019 with overheads). Table 3-8 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-8: Value of EUE and Market Benefits (Option 3)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	4.9	6.2	10.9	20.9	50.4	194.2	4.3	4.3	4.3	4.4
Weighted average EUSE ($M)	$0.20	$0.26	$0.45	$0.86	$2.08	$8.03	$0.18	$0.18	$0.18	$0.18
EUSE-Base Case ($M)	$0.20	$0.26	$0.45	$0.86	$2.08	$8.03	$43.36	$48.56	$54.84	61.99
Market Benefits ($M)	$-	$-	$-	$-	$-	$-	$43.18	$48.38	$54.66	$61.80

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-9 shows that this option is economically viable.

Table 3-9: Economic analysis of Option 3

	Total
Present value of costs	$35.7M
Present value of benefits	$131.6M
NPV – Net market benefit	$95.9M

3.5 OPTION 4: RUN TWO NEW FEEDERS FROM EAST PRESTON ZONE SUBSTATION AND UPGRADE THE TTS-PTN-EPN-TTS SUB TRANSMISSION LOOP

This option looks at supplying Yarrabend Development using 2 x 22 kV feeders from Jemena East Preston (EPN) Zone Substation. This option assumes that the No.2 transformer and the No.2 22kV bus at East Preston Zone Substation will be installed as part of the EP conversion program by 2022.

The existing sub transmission loop is also operating above its rating under single contingency condition, hence it needs to be upgraded to supply the new load from EPN.

3.5.1 TTS-PTN-EPN-TTS SUB TRANSMISSION LINES WORK

The existing sub transmission loop is supplying Jemena Preston (PTN) and East Preston (EPN) Zone Substation. Table 3-10 shows the current rating of the sub transmission lines:

Table 3-10: Sub Transmission Loop Rating (TTS-PTN-EPN)

Sub Transmission Line	Rating
TTS-EPN	65.2 MVA
TTS-PTN	81.2 MVA

Sections of the TTS-EPN and TTS-PTN needs to be reconductored or thermally upgraded to increase the rating of the sub transmission loop. Based on current analysis, the TTS-EPN section of the line will be operating above its N-rating under single contingency event with the new load from 2022.

The proposed scope of works include:

- Reconductor approximately 1,700m of 66 kV overhead conductor on the TTS-EPN line to increase the rating from existing 65.2 MVA to 83.5 MVA.

On completion of works, TTS-EPN sub transmission lines will be rated to 83.5 MVA.

The total cost of upgrading the TTS-EPN sub transmission line is estimated to be $2,000k ($2019). Based on the current forecast this project needs to be completed by November 2022.

Table 3-11 shows the existing risk on the TTS-PTN-EPN-TTS loop with the proposed Yarrabend load supplied from EPN Zone Substation.

Table 3-11: Value of Expected Unserved Energy (EUE) – TTS-PTN-EPN-TTS Sub Transmission Loop

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EUSE at 50% POE (MWh)	0.0	0.0	0.1	0.1	0.2	0.3	0.5	0.4	0.4	0.5
EUSE at 10% POE (MWh)	0.0	0.3	0.4	1.1	5.6	15.4	36.1	32.9	33.4	34.8
Weighted average EUSE (MWh)	0.0	0.1	0.2	0.4	1.8	4.8	11.2	10.1	10.3	10.8
Weighted average EUSE ($M)	$-	$0.00	$0.01	$0.02	$0.07	$0.20	$0.46	$0.42	$0.43	$0.45

On completion of the proposed project, there will be no load at risk under N and N-1 conditions on the TTS-PTN-EPN-TTS sub transmission loop.

3.5.2 EPN ZONE SUBSTATION WORKS

The existing EPN zone substation has 1 x 20/33 MVA 66/22 kV transformer supplying the No.3 22kV bus. This option assumes that Jemena will install the second transformer and the No.2 22kV bus at EPN zone substation.

On completion of the transformer and bus installation work as part of the EP conversion program, there will be sufficient capacity at EPN zone substation to supply the Yarrabend load under N condition.

However, there won't be spare circuit breakers at the zone substation to run the new feeders. Hence, a new 22kV bus needs to be installed at EPN and the transformer cable for the second transformer needs to be relocated to run to the new No.3 bus.

The scope of works, estimated cost and proposed timing for the works are as follow:

- Extend the existing control room to accommodate the No.3 bus at EPN and Install new 22 kV No.3 bus at EPN with four feeder CB and one CB for future capacitor banks. The estimated cost of extending the control room and installing new bus is $3,500k ($2019) and is required by November 2023.
- Decommission existing No.2 transformer 22 kV exit cable running to the No.2 bus at EPN and run new 2 x 630mm2 Cu cable from the No.2 transformer to the new No.3 bus at EPN. The estimated cost of replacing the transformer cable is $1,200k ($2019) and is required by November 2023.

3.5.3 EPN FEEDER UPGRADE WORK

All five breakers (4 feeder CBs and 1 capacitor bank CB) on the No.1 22 kV bus are currently fully utilised at EPN Zone Substation. As the second bus at EPN Zone Substation won't be installed until 2022 when the old 6.6 kV switchyard is decommissioned to make room for the new 22 kV switchgear expansion, a new 6.6 kV feeder from FF will be required initially to supply the load at Yarrabend Development till 2022. On completion of the EP conversion program there will only be one spare CB available from the new No.2 bus, hence a new third bus needs to be installed as part of the second feeder from EPN Zone Substation. Based on the current forecast under this option, two 22 kV feeders from EPN Zone Substation and one 6.6 kV feeder from FF Zone Substation will be installed in the coming EDPR period 2021-26.

The existing out of commissioned sub transmission line between EP and FF zone substation will be used to run one of the feeders from EPN. Given that area is densely populated Jemena might not be able to install new poles for overhead construction along the route.

The scope of works, estimated cost and proposed timing for the new feeders are as follow:

- New 6.6 kV FF94 feeder (heading south): Install a new 6.6 kV feeder CB (rated to 11kV) in the spare panel on Bus No.3. Install approximately 2,800 metres of new 3C.300mm2 AL XLPE underground cable from the existing 6.6kV feeder FF94 CB to the new kiosk substation as part of Stage 2 development. The proposed route for the new feeder are along McGregor St, Sparks Ave, Chingford St, Fulham Rd, Smith St, Keith St, Parklands Ave, Naroon Rd, Wingrove St, Lowther St, Heidelberg Rd and Latrobe Ave within Yarra Bend Development. The estimated cost for this new feeder is $4,169k ($2019) and is required by November 2022.
- New 22 kV EPN-021 feeder: Use the existing spare CB[9] on the No.2 22kV bus to run the new feeder. Install approximately 500m of new 300mm^2 Al XLPE cable in conduit from the CB to pole A00739 on Water Rd. Use the existing out of service (OOS) sub transmission line between EPN and FF. Run approximately 2000m of 300mm^2 AL XLPE cable in conduit with two spare HV conduit (spare conduit will be used by the second feeder from EPN) from pole A106731 along Grange Rd and Heidelberg Rd to a RMU within the former APF site to form the new feeder. The estimated cost for this new feeder is $3,565k ($2019) and is required by November 2023.
- New 22 kV EPN-011 feeder: Extend the existing bus at EPN by installing the No.1 22 kV bus. The new feeder EPN-011 will run from the new No.1 bus to provide a secure and reliable supply to Yarrabend.. Install approximately 6000m of new 300mm^2 AL XLPE cable in conduit from the CB along Quinn St,Bell St and Albert St (install one spare conduit along the route) to the spare conduit installed at Grange St as part of the No.1 feeder to Yarrabend. From Grange St use the spare conduit to run approximately 1500m of 300mm2 AL XLPE cable to a RMU within the APF site. The estimated cost of this new feeder is $9,815k ($2019) and is required by 2025.

The total cost including overheads for establishing two new 22 kV and one 6.6 kV feeder is estimated to be $17,549k in 2019 dollars. Since we are resolving the overloading issue on FF feeders by running the new feeders

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9 Assumed that the No.2 22kV bus will be installed as part of the EP conversion project

from EPN Zone Substation, the net market benefits for the new EPN feeders is equivalent to the value of EUE for the FF feeder base-case scenario presented in Table 3-1.

3.5.4 DELIVERABILITY RISK

The identified issues that can impact the deliverability of this proposed option include:

- This option has a dependency on the EP conversion program. Any changes to the delivery timing of the EP conversion program will leave significant risk at JEN FF supply area such that Jemena may not be able to provide connection services to its customers;
- EPN is currently a single transformer station and does not have capacity or spare CB's for feeder exits to supply the new load at Yarrabend Development. In order to supply Yarrabend Development from EPN the second transformer and the No.2 bus needs to be installed by 2022. Any changes to the delivery of the EPN project will have significant impact on this option.
- The proposed underground feeder has sections running within CitiPower distribution area. JEN has limited information about assets around that area which could impact the proposed route for the feeders.

Based on the above assessment Jemena has given a High deliverability risk profile for this option. Besides this, the option does not align with JEN long term strategy for the area. JEN long term plan is to convert FF Zone Substation to 11 kV network when it becomes economical. The 11 kV network at FF will support HB zone substation currently operating as an island. Running new 22 kV lines in areas supplied by 6.6 kV and 11 kV network will add new "islands" within the JEN network, which would degrade the supply reliability to this area over the long-term.

3.5.5 OPTION 4 - ECONOMIC ANALYSIS

The total project cost of upgrading the sub transmission line and zone substation to install two new 22 kV feeders and one 6.6 kV feeder for the Yarrabend development is estimated to be $24,249k in 2019 dollars. Table 3-12 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-12: Value of EUE and Market Benefits (Option 4)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	4.8	5.4	6.8	6.7	34.9	4.3	4.3	4.3	4.4	4.4
Weighted average EUSE ($M)	$0.20	$0.22	$0.28	$0.28	$1.44	$0.18	$0.18	$0.18	$0.18	$0.18
EUSE-Base Case ($M)	$0.20	$0.22	$0.28	$0.28	$1.44	$6.94	$41.16	$45.66	$51.21	$58.35
Market Benefits ($M)	$-	$-	$-	$-	$-	$6.77	$40.98	$45.48	$51.03	$58.16

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-16 shows that this option is economically viable.

Table 3-13: Economic analysis of Option 4

	Total
Present value of costs	$19.4M
Present value of benefits	$128.8M
NPV – Net market benefit	$109.4M

3.6 OPTION 5: CONVERSION OF FAIRFIELD ZONE SUBSTATION FROM 6.6 KV TO 11 KV AND UPGRADE BTS-FF SUB TRANSMISSION LINE

As part of the FF transformer replacement project to be completed by November 2019 two of the three 10/13.5 MVA 22/6.6 kV transformers will be converted to 12/18 MVA 22/11-6.6 kV units. This provides an opportunity for converting FF feeders from 6.6 kV to 11 kV.

The 6.6 kV distribution voltage is a legacy of the early-20th century and in urban areas it is inadequate to efficiently support the loads of the 21st century. JEN's long-term objective is to convert its 6.6 kV distribution network to 11 kV when it becomes economic to do so. If the FF 6.6 kV feeders are converted to 11 kV, the overall MVA capacity of the existing feeders supplying JEN customers will increase by 107%, from 20.6 MVA to 42.6 MVA, as shown in Table 3-14. Hence no additional feeders would be required for the foreseeable future following the completion of the conversion program.

The conversion program will not resolve the overload issue on the BTS-FF sub transmission loop. Hence, as part of this option, the BTS-FF sub transmission loop needs to upgraded the same as in Option 2 costing $6,469k in real 2019 dollars.

Table 3-14: FF 6.6 kV feeder ratings

Feeder	Summer Rating (A) Before conversion	Summer Rating (A) After conversion	Summer MVA Rating	
			6.6 kV	11 kV
FF087	285	375	3.3	7.1
FF088	285	375	3.3	7.1
FF089	285	375	3.3	7.1
FF090	375	375	4.3	7.1
FF095	285	375	3.3	7.1
FF096	285	375	3.3	7.1
Overall feeder capacity			20.6	42.6

Conversion of FF Zone Substation to 11 kV will help to provide backup capability for the isolated 11 kV distribution network of HB Zone Substation, and vice-versa. Furthermore, over the past decade JEN has been procuring distribution transformers as a standard with dual 11 kV and 6.6 kV primary windings for its 6.6 kV network. Hence, not all distribution transformers will need to be replaced when the 6.6 kV network of FF Zone Substation is converted to 11 kV. Redevelopment of FF Zone Substation from 22/6.6 kV to 22/11 kV brings the following benefits:

- Increases the overall MVA capacity of the existing FF feeders by 107% (from 20.6 MVA to 42.6 MVA);

- Meets the electricity needs of new customers in the area;
- Meets growth in the demand of the existing customers in the area; and
- Provides backup feeder capability for the isolated 11 kV network of HB Zone Substation and vice versa.

Table 3-15: JEN FF feeder 6.6 kV to 11 kV conversion costs

Conversion Year	Sub Transmission Works ($'000)	Conversion of Dist. Subs. ($'000)	Conversion of feeders ($'000)	Zone Sub Conversion ($'000)	Total (2019 dollars) ($'000)
2022-23	$6,469	$2,457	$4,096	$500	$16,121
2024-25	$0	$2,438	$4,154	$500	$9,703
2025-26	$0	$2,951	$3,670	$500	$9,745
Total					$35,568

The total cost including overheads of converting JEN's FF feeders from 6.6 kV to 11 kV is estimated to be $29,099k in 2019 dollars. Costs for each conversion year are shown in the Table 3-15. The zone substation works below only includes associated primary works for changing the transformer tap voltage and temporary secondary protections works required during the changer-over/interim stage with 3 buses being split into three stages. The total cost currently does not include the cost to convert six of CitiPower's FF feeders which would subsequently be required if JEN proceeds with the conversion works. Since we are resolving the overloading issue on FF feeders by converting the FF 6.6 kV feeders to 11 kV, the net market benefits is equivalent to the value of EUE for the FF feeder base-case scenario presented in Table 3-1 (i.e. resolving all the FF feeder overload risks).

3.6.1 DELIVERABILITY RISK

The deliverability risk of this option is high because 6 out of 12 feeders cross the boundary between JEN and CitiPower to supply CitiPower's customers. Jemena has been working closely with CitiPower to review the need and timing for conversion of CitiPower's 6.6 kV feeders. The cost provided above does not include works required by CitiPower to convert their six feeders to 11 kV. Hence, at this time, it is not the most economically viable to bring this option forward. In addition, the delivery and staging of the conversion works under this option will required further detailed analysis and investigation to determine the full extent of the scope and potential additional costs associated with maintaining customer's supply whilst undertaking the conversions of the first bus and it's feeders.

3.6.2 OPTION 5 - ECONOMIC ANALYSIS

The total project cost of upgrading the BTS-FF sub transmission line and conversion of FF zone substation feeders from 6.6 kV to 11kV is estimated to be $35,568k in 2019 dollars. Table 3-16 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-16: Value of EUE and Market Benefits (Option 5)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	6.0	6.6	8.0	9.6	0.0	0.0	0.0	0.0	0.0	0.0
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
EUSE-Base Case ($M)	$0.25	$0.27	$0.33	$0.48	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67
Market Benefits ($M)	$-	$-	$-	$0.08	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-17 shows that this option is economically viable.

Table 3-17: Economic analysis of Option 5

	Total
Present Value of Costs	$31.1M
Present value of benefits	$131.6M
NPV - Net market benefit	$100.5M

3.7 OPTION 6: ESTABLISH A NEW ZONE SUBSTATION AND INSTALL NEW BTS-YARRABEND SUB TRANSMISSION LOOP

This option looks at installing a new substation to supply the new load at Fairfield and Alphington area

Possible options for establishing a new zone substation in Fairfield are:

- A new 22/6.6 kV zone substation;
- A new 22/11 kV zone substation; and
- A new 66/11 kV zone substation.

Acquiring a new site and establishing a new zone substation in the area is not viable for the following reasons:

- FF Zone Substation currently has sufficient space (vacant land) for reinforcement works, if required in future;
- On the present forecasts, a second zone substation in the area will not be required for the foreseeable future as Jemena is upgrading the transformers to 12/18 MVA.
- JEN does not own any vacant zone substation sites in Fairfield or Alphington near Yarrabend Development. Acquiring a vacant site and planning permits for a new zone substation and sub-transmission lines in the area would be very difficult and costly.
- A new zone substation at Yarrabend Development is not possible as the developers are not interested in building a zone substation in the vicinity.

3.7.1 OPTION 6 - ECONOMIC ANALYSIS

Depending on the sub-transmission voltage (66 kV or 22 kV) and the upstream terminal station source of supply (BTS, Thomastown Terminal Station etc.), cost of establishing a new zone substation will likely exceed $50M.

This is also the most expensive network option and is not the preferred solution. However for completeness, Table 3-18 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-18: Value of EUE and Market Benefits (Option 6)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	6.0	6.6	8.0	9.6	0.0	0.0	0.0	0.0	0.0	0.0
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EUSE-Base Case ($M)	$0.25	$0.27	$0.33	$0.48	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67
Market Benefits ($M)	$-	$-	$-	$0.08	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-19 shows that this option is economically viable.

Table 3-19: Economic analysis of Option 6

	Total
Present Value of Costs	$48.7M
Present value of benefits	$131.6M
NPV - Net market benefit	$82.9M

3.8 OPTION 7: BATTERY STORAGE

The forecast maximum demand provided by the developer has already accounted for the distributed energy resource proposed at the development. Based on the current demand forecast the development will have a maximum demand of [redacted]

This option looks at supplying the Yarrabend development using the new FF-093 feeder proposed to be commissioned by November 2020 and install grid scale battery systems to manage the future demand at Yarrabend development.

Based on JEN analysis, approximately 65MWh / 9MW battery will be required to manage the system normal risk due to the future new loads at the development for the next 10 years. To install these batteries approximately 400m^2 of real estate needs to be procured.

Based on an average cost of $1,930 per kW and $480 per kWh[10] the total cost of installing the new energy storage system at NS Zone Substation is estimated at $47,681[11] in 2019 dollars.

10 National Renewable Energy Lab, US, https://www.nrel.gov/docs/fy19osti/71714.pdf

11 This report used a conversion rate of $1.45 AUD for $1.00 USD

3.8.1 RESIDUAL RISK

This option will not fully eliminate the expected unserved energy at risk under contingency conditions on the BTS-FF sub transmission lines. The below identified risk will remain in the lines after the completion of this option:

- This option will not mitigate the N-1 risk on the sub transmission lines. Under single contingency condition, load will be shed from FF Zone Substation under this option.
- This option will not mitigate the existing N-2 risk on the sub transmission lines. Both BTS-FF184 and BTS-FF188 and BTS-FF181 and BTS-FF184 lines will still be running along the same pole line and an outage on both circuits (e.g. vehicle impact on the common pole line) could result in the loss of the entire supply at FF Zone Substation.
- The proposed energy storage system will only mitigate the system normal risk on the sub transmission lines for the next ten years. If maximum demand continues to increase at FF Zone Substation, then additional batteries may be required to address the system normal risk.

3.8.2 DELIVERABILITY RISK

The deliverability risk for this option is high due to the following constraints:

- Fairfield being a well-developed suburb it will be extremely difficult to find a suitable real estate to install the grid scale battery systems which requires a large footprint. Noting costs for land procurement have not been included.
- Compared to other utility assets like kiosk and pole top transformers, grid scale batteries are fairly new technology. The safety concerns of installing large grid scale battery systems next to residential houses needs to be assessed. This could lead to additional cost to account for risk mitigation methods.

3.8.3 OPTION 7 - ECONOMIC ANALYSIS

The total project cost of installing a new grid scale 9MW / 65MWh battery is estimated at $47.7M in 2019 dollars. Table 3-20 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-20: Value of EUE and Market Benefits (Option 7)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	6.0	6.6	8.0	9.6	10.7	13.0	15.6	18.3	18.3	18.5
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.44	$0.54	$0.64	$0.76	$0.76	$0.76
EUSE-Base Case ($M)	$0.25	$0.27	$0.33	$0.48	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67
Market Benefits ($M)	$-	$-	$-	$0.08	$1.21	$6.60	$40.60	$45.22	$50.78	$57.91

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-21 shows that this option is economically viable.

Table 3-21: Economic analysis of Option 7

	Total
Present Value of Costs	$39.8M
Present value of benefits	$129.0M
NPV - Net market benefit	$89.2M

3.9 OPTION 8: DEMAND MANAGEMENT IN FIRST TWO YEARS, THEN OPTION 2

This option is applying demand management for the first two years, followed with the implementation of Option 2 as outlined in Section 3.3 above. Effectively, this option is looking at deferring the capital expenditure in Option 2 by two years using demand management.

Demand management schemes have the potential to reduce peak demand on the electricity network and thereby defer the requirement for network augmentation. This is achieved by customers shifting their usage to off-peak or reducing their overall consumption by using energy efficient appliances and reducing energy wastage.

Demand management schemes could include, interruptible loads offered in return for a reduced electricity price, innovative tariffs that will encourage customers to reduce their usage during peak periods, etc.

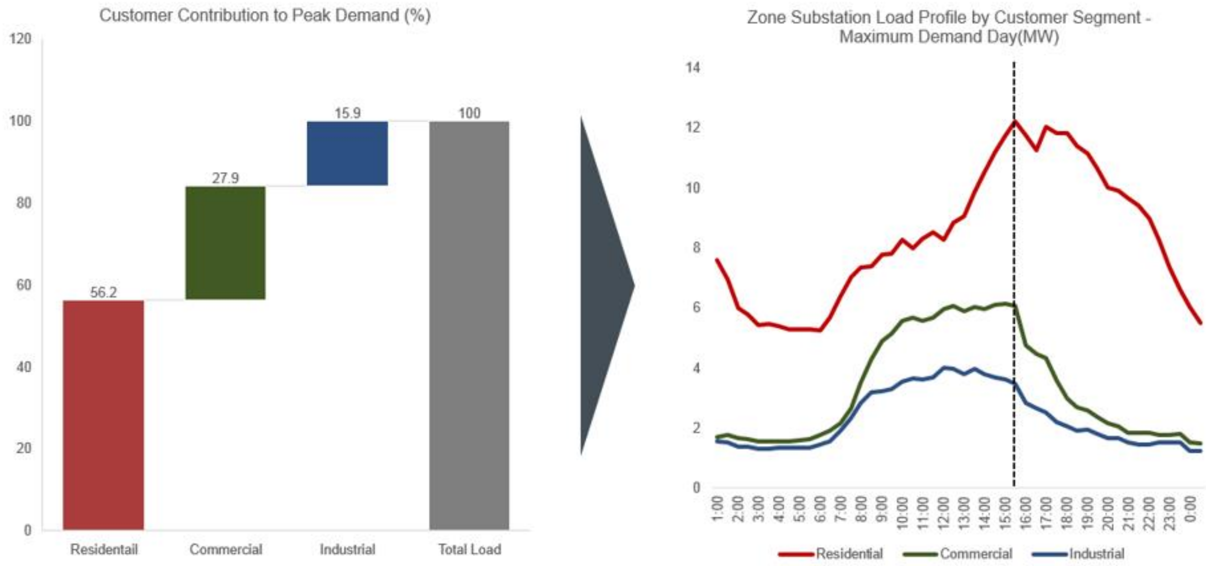
FF Zone Substation area supplies approximately 6,400 JEN customers. The zone substation is mainly supplying residential customers. Table 3-22 shows the customer segments under FF zone substation.

Table 3-22: Customer Number FF Zone Substation

Customer Segment	Number
Residential	5,972
Commercial	360
Industrial	9

Figure 5 below shows the customer contribution to peak demand at FF zone substation. Commercial and Industrial customers account for approximately 10MW load during peak demand.

Figure 5: FF Customer Contribution to Peak Demand



At the time of preparation of this development plan there were no known proponents for demand management on the JEN network in the FF supply area. Proponents for demand management are encouraged to express their interest to JEN at any time.

Based on an average set up fee of $60,000 MW[12] and a dispatch fee of $5,000 per MWh[13] the total cost of initiating the demand management programme for two year is estimated at $3,585k in 2019 dollars. This option will defer the network project for two years. Following this, Jemena will need invest $21.9 million ($2019) to upgrade the BTS-FF sub transmission line and to install four new feeders for the Yarrabend development.

3.9.1 RESIDUAL RISK

This option will not fully eliminate the expected unserved energy at risk under contingency conditions on the BTS-FF sub transmission lines. The below identified risk will remain in the lines after the completion of this option:

- This option will not mitigate the N-1 risk on the sub transmission lines. Under single contingency condition, load will be shed from FF Zone Substation under this option.
- This option will not mitigate the existing N-2 risk on the sub transmission lines. Both BTS-FF184 and BTS-FF188 and BTS-FF181 and BTS-FF184 lines will still be running along the same pole line and an outage on both circuits (e.g. vehicle impact on the common pole line) could result in the loss of the entire supply at FF Zone Substation.

3.9.2 DELIVERABILITY RISK

The deliverability risk of managing load by demand management is considered high due to the following identified issues:

12 The setup fee is annual fee spend to reserve capacity to reduce demand.

13 The dispatch fee is paid per event for the amount of energy reduced

- Fairfield Zone Substation is mainly supplying residential customers, there aren't any single large customers in this area. Hence, it will be harder to find Commercial and Industrial demand management customers to participate in the demand management programme;
- Based on Jemena's experience with residential demand management, the customer sign up for the programme is low. FF being a residential zone substation in an affluent suburb, it will be hard to find customers to participate in residential demand management;
- Load growth in this area is mainly driven by Yarrabend Development, and as such, any demand management that may be suitable to defer network investment would need to come from this development. Jemena has already discussed this potential demand management with the developer, and the load growth allowance has already account for this net demand reduction.

3.9.3 OPTION 8 - ECONOMIC ANALYSIS

The total project cost of demand management for two years followed by Option 2 is estimated at $25.4M in 2019 dollars. Table 3-23 summarises the annualised value of the expected unserved energy (EUE) and market benefits for this option over the next ten years (2020-2029).

Table 3-23: Value of EUE and Market Benefits (Option 8)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Weighted average EUSE (MWh)	6.0	6.6	8.0	9.6	10.7	13.0	0.0	0.0	0.0	0.0
Weighted average EUSE ($M)	$0.25	$0.27	$0.33	$0.40	$0.44	$0.54	$0.00	$0.00	$0.00	$0.00
EUSE-Base Case ($M)	$0.25	$0.27	$0.33	$0.48	$1.65	$7.14	$41.24	$45.98	$51.54	$58.67
Market Benefits ($M)	$-	$-	$-	$0.08	$1.21	$6.60	$41.24	$45.98	$51.54	$58.67

Based on an annual discount rate of 6.20% and a planning horizon of 10 years, Table 3-24 shows that this option has a positive NPV and is economically viable.

Table 3-24: Economic analysis of Option 8

	Total
Present value of costs	$21.6M
Present value of benefits	$130.8M
NPV – Net market benefit	$109.2M

3.10 OPTION 9: EMBEDDED GENERATION

Embedded generation can be an alternative for the alleviation of network inadequacies and constraints, thereby deferring the need for major reinforcement projects. In order to defer any network augmentation projects, the embedded generation would need to be connected to, and supply into, the 6.6 kV distribution network where constraints exist.

At the time of writing this strategy paper there were no known proponents for connection of embedded generation to the JEN network in the FF supply area. Proponents for embedded generation are encouraged to apply or express their interest to JEN at any time.

4. ANALYSIS OF OPTIONS

Table 4-1 presents a summary of the overall economic analysis of credible options considered in this report.

Table 4-1 Summary of economic analysis results

Option	Option name	Project cost (real $2019)	NPV of Net Market Benefits	Ranking
1	Do Nothing (base-case)	-	-$132.7M	8
2	Establish four new feeders (6.6 kV) from Fairfield Zone Substation to Yarrabend Development and upgrade BTS-FF sub transmission line	$21.9M	$114.8M	1
3	Establish three new feeders (11 kV) from Heidelberg Zone Substation to Yarrabend Development and upgrade TSTS-HB-Q-L sub transmission loop	$44.6M	$95.9M	5
4	Establish two new feeders (22 kV) from East Preston Zone Substation (EPN) to Yarrabend Development and upgrade TTS-EPN-PTN-TTS sub transmission loop	$24.2M	$109.4M	2
5	Conversion of Fairfield Zone Substation from 6.6 kV to 11 kV and upgrade BTS-FF sub transmission line	$35.6M	$100.5M	4
6	Establish a new 22 kV/6.6 kV zone substation at Yarrabend Development and install new BTS-Yarrabend sub transmission loop Battery Storage Solutions	$50.0M	$82.9M	7
7	Battery Storage Solutions	$47.7M	$89.2M	6
8	Demand management in first two years, then Option 2	$25.4M	$109.2M	3

Option 2 to establish four new 6.6 kV feeders (rated at 11 kV) and upgrade the BTS-FF sub transmission line is the option that maximises the net market benefits compared to all considered options, and is therefore the preferred credible option.

5. RECOMMENDATIONS AND CONCLUSIONS

The FF 6.6 kV feeders and the BTS-FF sub transmission lines are currently highly utilized and on the present forecasts it is assessed that they will not have sufficient capacity to meet the projected needs of the customers in the area. By summer 2025/26, the average utilisation of FF 6.6 kV feeders is projected to reach 145% under 10% Probability of Exceedance (POE) conditions, and an outage on one of the BTS-FF 22 kV lines at the time of peak demand will overload the remaining BTS-FF 22 kV lines by up to 60%.

A number of options to alleviate the emerging constraints were considered:

- Option 1: Do nothing (Base Case);
- Option 2: Establish four new feeders (6.6 kV) from Fairfield Zone Substation to Yarrabend Development and upgrade BTS-FF sub transmission line;
- Option 3: Establish three new feeders (11 kV) from Heidelberg Zone Substation to Yarrabend Development and upgrade TSTS-HB-Q-L sub transmission loop;
- Option 4: Establish two new feeders (22 kV) from East Preston Zone Substation (EPN) to Yarrabend Development and upgrade TTS-EPN-PTN-TTS sub transmission loop;
- Option 5: Conversion of Fairfield Zone Substation from 6.6 kV to 11 kV;
- Option 6: Establish a new 22 kV/6.6 kV zone substation at Yarrabend Development;
- Option 7: Battery Storage Solutions
- Option 8: Demand management in first two years, then Option 2
- Option 9: Embedded Generation

Option 2 to establish four new 6.6 kV feeders (rated at 11 kV) and upgrade BTS-FF sub transmission line with a total estimated expenditure in real 2019 dollars of $21.9 million maximises the net economic benefit to customers and is the preferred option. Option 2 will also align with the long-term strategy for the area and allow the FF feeders to economically be converted to 11 kV in the future. The new 6.6 kV feeders will address both the present feeder load at risk as well as providing capacity to supply new developments in the Fairfield and Alphington area.

Based on the customer forecast approximately [redacted] of load is expected to be drawn by the new development at Yarrabend Development by 2026. However, considering the current economic condition, Jemena has used a more considerate approach and is only expecting approximately 10.8 MVA load by 2026. Hence, the recommendation is to install only two new feeders and upgrade the sub transmission line in next EDPR period (2021-26). The last two feeders will be installed in the following EDPR period 2026-30. Table 5-1 shows the proposed timing of investment at FF area to meet the growing demand.

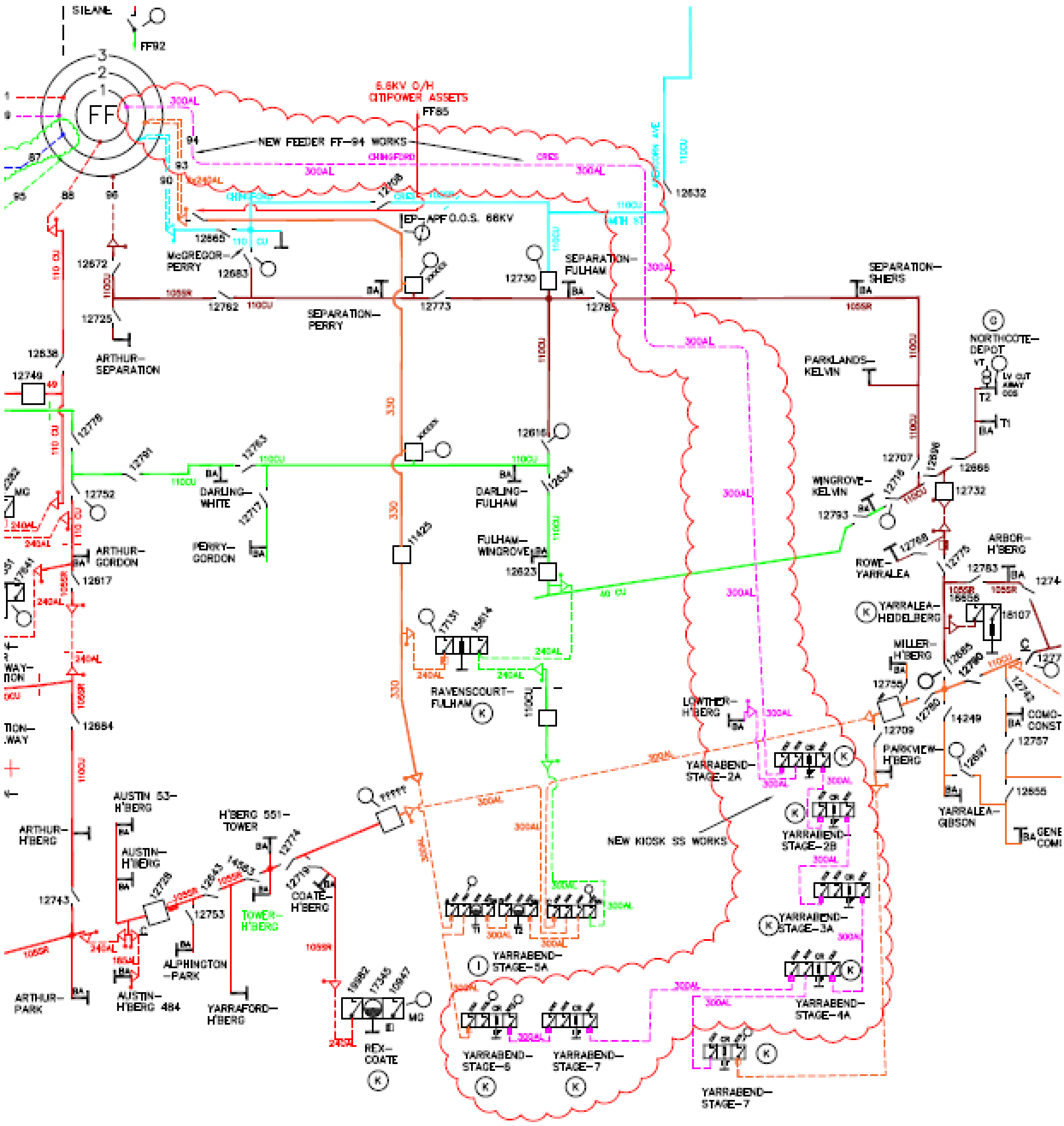
Table 5-1: Recommended Timing on Preferred Option

New 6.6kV Feeder	Installation Year	EDPR	Costs (2019 dollars) with Overheads ($'000)
BTS-FF No.4	2023	2021-26	$6,506
FF-094	2022	2021-26	$3,785
FF-098	2024	2021-26	$5,091
FF-099	2027	2026-30	$3,377
FF-100	2029	2026-30	$3,127

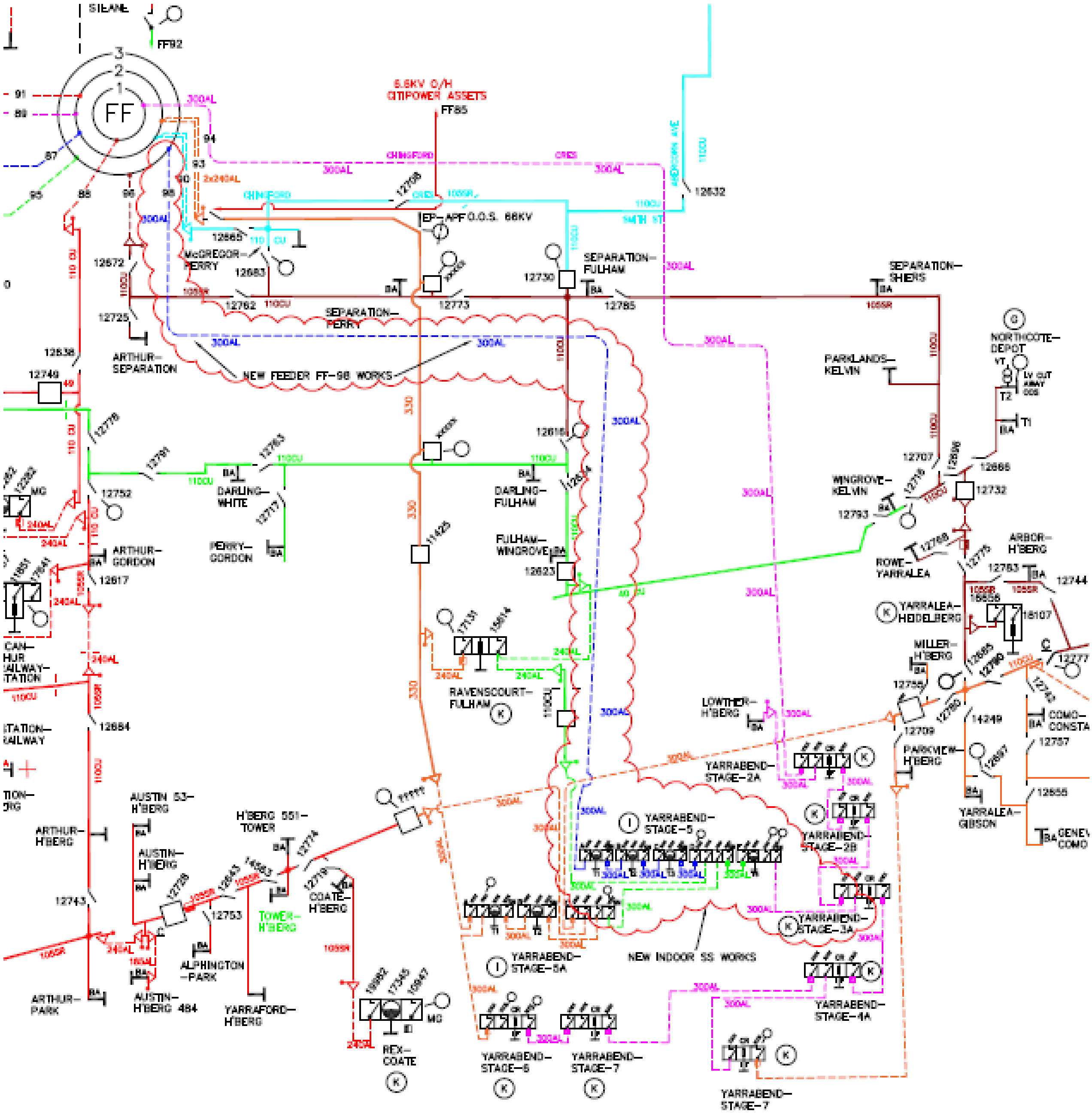
However JEN will continue to reassess any change in the load forecasts annually in order to optimise the timing of the project. If the load growth in this area is as expected or faster than the current forecast, then the timing of future new FF feeders will be brought forward as required to meet customers' needs.

6. APPENDIX A: OPTION 2 PROPOSED NETWORK CONFIGURATION

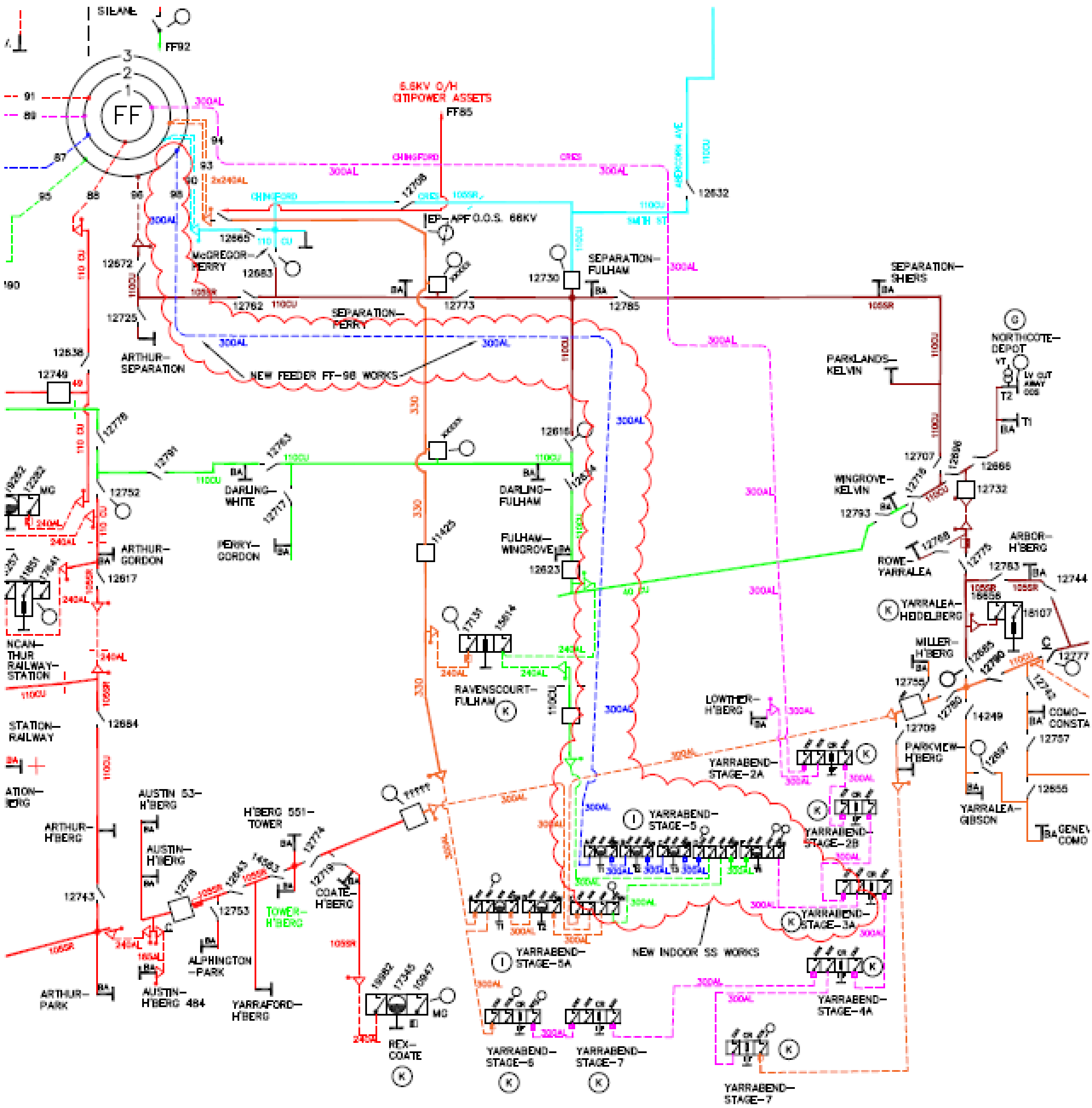
6.1 STAGE 1 - NEW FEEDER FF-094



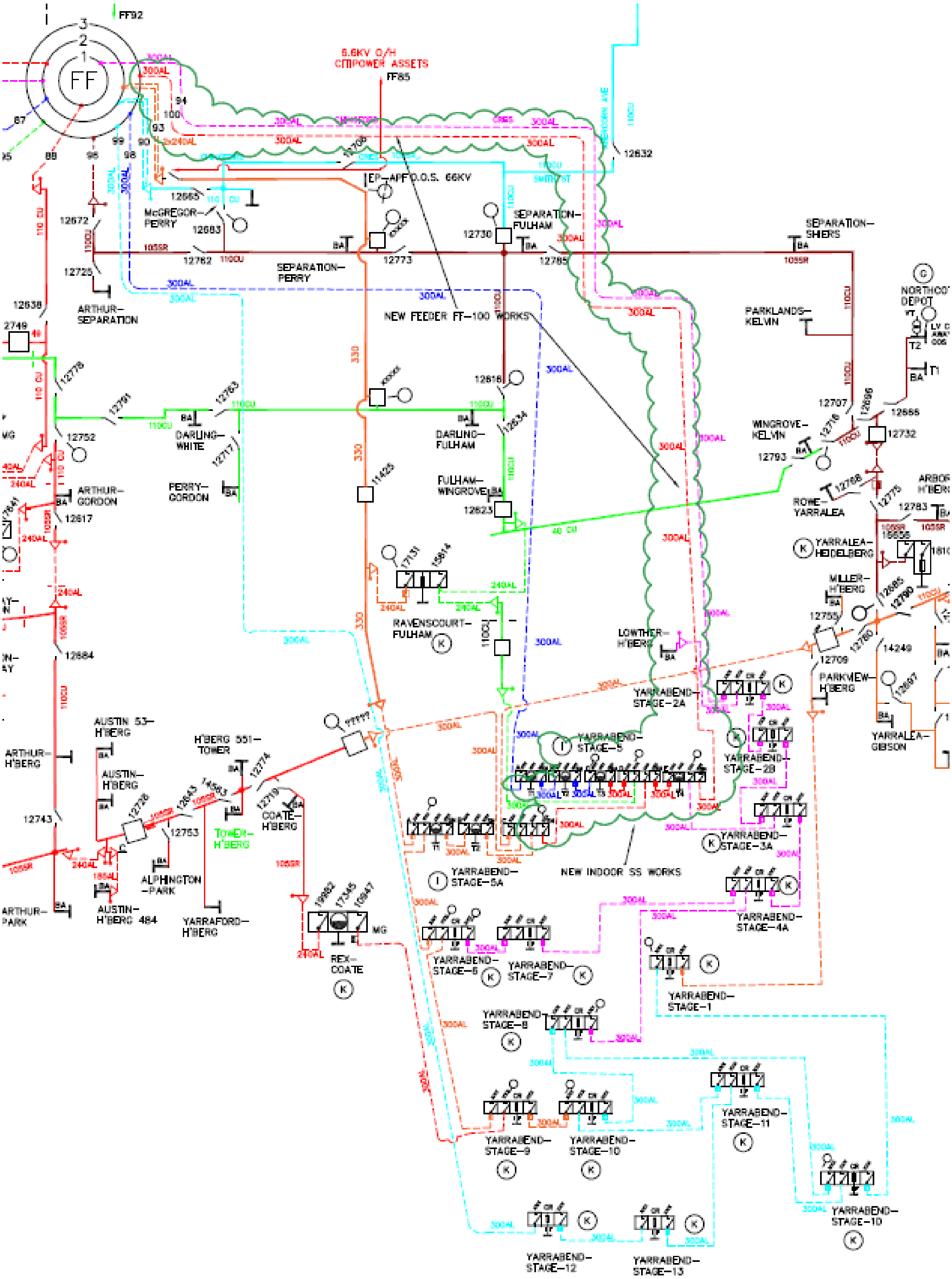
6.2 STAGE 2- NEW FEEDER FF-098



6.3 STAGE 3- NEW FEEDER FF-099



6.4 STAGE 4- NEW FEEDER FF-100



1. Confidentiality Qualification

The following from Appendix A and Appendix B have been excluded from this document as they are wholly confidential:

- Attachment A
- Attachment B
- Attachment C
- Attachment D
- ACIF Market Report