Jemena Electricity Networks (Vic) Ltd

2026-31 Electricity Distribution Price Review Proposal

22 kV Central Area Network Development Strategy

ELE-999-PA-EL-0005

Authorisation

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History

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1.1	02/09/2024	2024 demand forecasts	Rodney Bray
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Owning Functional Area

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Glossary

10% POE (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE (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.
Augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation is usually triggered by growing customer demand in areas of the network with limitations.
Capacity	Refers to the network's capability to transfer electricity to customers.
Continuous Rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Cyclic Rating	The permissible maximum demand to which a conductor or cable may be loaded on a cyclic basis.
Consumer Energy Resources (CER)	Solar PV, micro-generators, batteries (including electric vehicles), flexible load and other Embedded Generation connected within the distribution network.
Discount Rate	The regulated Weighted Average Cost of Capital (WACC).
Distribution Feeders	Radial 22kV, 11kV or 6.6kV powerlines that emanate from zone substations to supply Distribution Substations or HV customers.
Exit Cable	The underground cable connected to the HV distribution feeder circuit breaker that leaves the boundary of the zone substation.
Expected Unserved Energy (EUE)	Refers to an estimate of the long-term, probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 360,000 customers via an 11,000-kilometre distribution system covering north-west greater Melbourne.
Limitation	Refers to a limitation on a network asset's ability to transfer power due to its rating, failure rate or condition.
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.
Network	Refers to the physical assets required to transfer electrical energy to customers.
Non-network	Refers to anything potentially affecting the transfer of electricity to customers that does not involve the network.

Non-network alternative	A response to growing customer demand that does not involve a traditional network solution.
Open Point	An isolation device on a distribution feeder that is in a normally open state.
Operations & Maintenance expenditure (O&M)	Expenditure (ongoing) for operating and maintaining the network.
Power Factor (pf)	The ratio of active power to apparent power. A unity power factor indicates no reactive power through the element. Power factor is specified as either leading or lagging.
Present Value	The value of a cost or benefit in the future, discounted to today's value using the Discount Rate.
Probability of exceedance (PoE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year.
Probabilistic Planning	A planning methodology involving estimating the cost of a network limitation with consideration of demand, network capability, and the likelihood and severity of network outages and operating conditions.
Reconductor(ing)	Replacing a section of conductor with another of higher rating.
Regulatory Investment Test for Distribution (RIT-D)	A test administered by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments in the National Electricity Market (NEM).
Reliability	The measure of the duration or frequency of the distribution system to provide uninterrupted supply to customers over a defined time.
Sub-transmission	Overhead lines and underground cables connecting terminal stations to zone substations. These are operated at 66 kV.
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.
Terminal Station	Sites where transmission voltages are transformed down to sub-transmission voltages. These sites and the assets within them are not owned by JEN.
Transfer Capability	The amount of capacity available for a load transfer from one substation to another.
Transmission Connection Assets	The assets within a Terminal Station that are planned by JEN and the other DNSPs that are connected to the Terminal Station.
Utilisation	The Maximum Demand expressed as a percentage of its rating.
Value of Customer Reliability (VCR)	Represents the dollar value customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).
Zone Substation	Sites where sub-transmission voltages are transformed down to distribution voltages. These sites are owned by JEN. They are the upstream supply source for HV distribution feeders.

Abbreviations

A	Ampere
AAC	All Aluminium Conductor
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
CB	Circuit Breaker
CHP	Cable Head Pole
CIC	Customer Initiated Capital
CN	Coburg North Zone Substation
CS	Coburg South Zone Substation
CER	Consumer Energy Resources
DM	Demand Management
(E)	Existing
EPN	East Preston Zone Substation
EUE	Expected Unserved Energy
EV	Electric Vehicle
(F)	Future
HV	High Voltage
JEN	Jemena Electricity Network
kV	kilovolts
MD	Maximum Demand
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NDS	Network Development Strategy
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules or Neutral Earthing Resistor (depending on context)
(N)	New (or system normal - all critical plant in service, depending on context)
(N-1)	Single contingency - a single critical item of plant out service
NEI	Customer Zone Substation

NEL	Customer Zone Substation
NH	North Heidelberg Zone Substation
N/O	Normally Open
NPV	Net Present Value
O&M	Operations and Maintenance
OH	Overhead Line
OLTC	On-Load Tap-Changer
OOS	Out of Service
PF	Power Factor
PoE	Probability of Exceedance
PTN	Preston Zone Substation
PV	Photovoltaic
PVR	Present Value Ratio
RCGS	Remote Controlled Gas-insulated Switch
REFCL	Rapid Earth Fault Current Limiter
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SAPS	Standalone Power Systems
SLD	Single Line Diagram
STPIS	Service Target Performance Incentive Scheme
TCPR	Transmission Connection Planning Report
TT	Thomastown Zone Substation (owned by AusNet Services)
TTS	Thomastown Terminal Station (owned by AusNet Services)
UG	Underground Cable
V2G	Vehicle to Grid
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code
WACC	Weighted Average Cost of Capital
WT	Watsonia Zone Substation (owned by AusNet Services)

Executive Summary

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

Our customers expect us to deliver and maintain a reliable electricity supply at the lowest cost over the lifecycle of our assets. To do this, we must choose the most prudent and efficient solutions that address current and emerging network limitations. In the context of the National Electricity Market (**NEM**), this means choosing an investment plan that maximises the present value of net economic benefits to all those who produce, consume and transport electricity.

This document articulates the Network Development Strategy (**NDS**) and plan for the area of the Jemena Electricity Network (**JEN**) servicing the suburbs of Coburg, Coburg North, Pascoe Vale, Pascoe Vale South, Fawkner, Reservoir, Kingsbury, Macleod, Heidelberg West, Heidelberg Heights, Rosanna, Viewbank and Yallambie. This supply area is serviced by our Coburg North (**CN**), Coburg South (**CS**), North Heidelberg (**NH**) zone substations as well as JEN feeders supplied from AusNet's Thomastown (**TT**) and by way of a network of 22 kV distribution feeders. This supply area currently comprises of over 76,277 electricity distribution customers.

This NDS presents the current and emerging limitations within this supply area over a 10-year planning horizon and articulates the need for augmentation and other capital works in order to address the identified network needs.

Identified Needs

The population of the supply area is 219,134 and this is forecast to grow to 270,328 by 2036, an increase of 23.4% (or 1.7% pa). Growth in the supply area is predominantly infill and subdivision of existing residential development with a couple of major customer developments.

Maximum electricity demand for the supply area is expected to grow on average by 2.7% per annum during the next 10-year period, driven primarily by population growth, business development and electrification. Given this growth, parts of the existing sub-transmission network, zone substations and 22 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand.

A number of existing network assets in the area are already (or forecast to be) highly utilised including one zone substation (being CS), one sub-transmission network (being TTS-NEI-NH-NEL-WT-TTS), and at least four 22 kV distribution feeders. Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of electricity supply reliability.

Options Considered

This NDS presents a range of credible options to meet the forecast demand for electricity over a 10-year planning horizon and maintain a safe and reliable supply to customers within the supply area. These include:

- Option 1: **Do Nothing** (base case).
- Option 2: **North Heidelberg Plan**.
- Option 3: **North Heidelberg and Coburg Plan**;
- Option 4: Battery Energy Storage System (BESS) Plan; and
- Option 5: Demand Management (DM) Plan.

A summary of the 20-year economic cost-benefit analysis, assessed for each option over a 10-year investment period, is presented in Table ES–1-1.

Table ES–1-1: Summary of Cost-Benefit Analysis ($M Real 2024)

Option	Total Capital Cost	Present Value of Capital and O&M Cost	Present Value of Reliability Benefit	Net Present Value (NPV)	Ranking
Option 1 – Do Nothing	0.0	0.0	0.0	0.0	5
Option 2 – North Heidelberg Plan	**15.2**	**16.2**	**911**	**895**	**1**
Option 3 – North Heidelberg and Coburg Plan	30.0	32.5	913	880	2
Option 4 - BESS Plan	0	475	911	436	4
Option 5 – DM Plan	0	194	911	717	3

Preferred Option

The assessment demonstrates that the preferred network development plan is to implement Option 2 (North Heidelberg Plan) because this option maximises the net economic benefits. to all those who produce, consume and transport electricity in the NEM. The preferred Option 2 provides a 20-year present value net market benefit of $895 million, with a present value of $14.1 million of investment (over 10-years). The market benefits forecast to be delivered by the preferred solution are driven by a reduction in the amount of expected unserved energy over the analysis period. The preferred network Option 2 to address the network limitations include the following project components**:**

Table 1-2: Option 2 – North Heidelberg Plan

Timing	Projects	Cost (Real 2024)	Limitation Addressed
2027	Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop	[redacted]	NEI-NH-NEL-WT overload
2028	Augment feeder TT0-011	[redacted]	TT 10 overload
2030	Augment feeder CS0-005	[redacted]	CS 05 overload
2031	Augment section of NH0-002	[redacted]	NH 02 overload
2031	Load transfers from CN 06 to CN 04 and CN 10	[redacted]	CN 06 overload
Total		**$15.2 million**	
Present Value Total		**$14.1 million**	

The estimated total capital cost of Option 2 for JEN over 10-years to address the identified network limitations is $15.2 million ($2024, Real). A sensitivity analysis was carried out to assess the effect of changing the capital costs, discount rate and demand forecasts. The results showed that changing these variables can have a slight change to the optimal timing of some projects in the development plan but does not change Option 2 as the preferred option.

1. Introduction

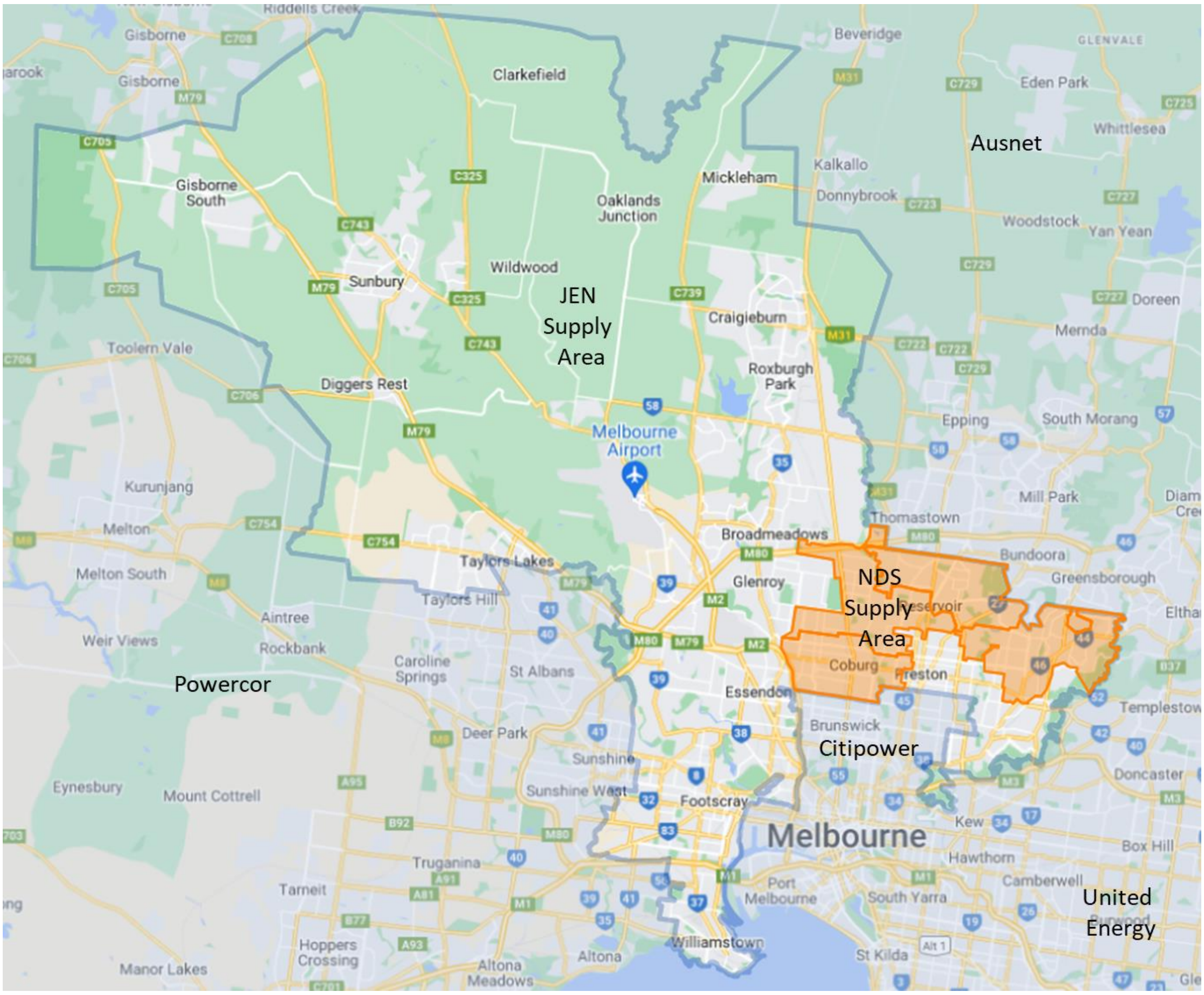
This chapter outlines the purpose of this NDS, provides an overview of the supply area, describes the general arrangement of the electricity network, and gives a brief overview of the network limitations in this area.

1.1 Purpose

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The JEN network service area ranges from Gisborne South, Clarkefield and Mickleham in the north, to Williamstown and Footscray in the south, and from Hillside, Sydenham and Brooklyn in the west, to Yallambie and Heidelberg in the east, as shown in Figure 1-1.

This document articulates the NDS for the electricity network servicing the suburbs of Coburg, Coburg North, Pascoe Vale, Pascoe Vale South, Fawkner, Reservoir, Kingsbury, Macleod, Heidelberg West, Heidelberg Heights, Rosanna, Viewbank and Yallambie. It presents the current and emerging limitations within this supply area over a 10-year planning horizon and identifies options to resolve these constraints.

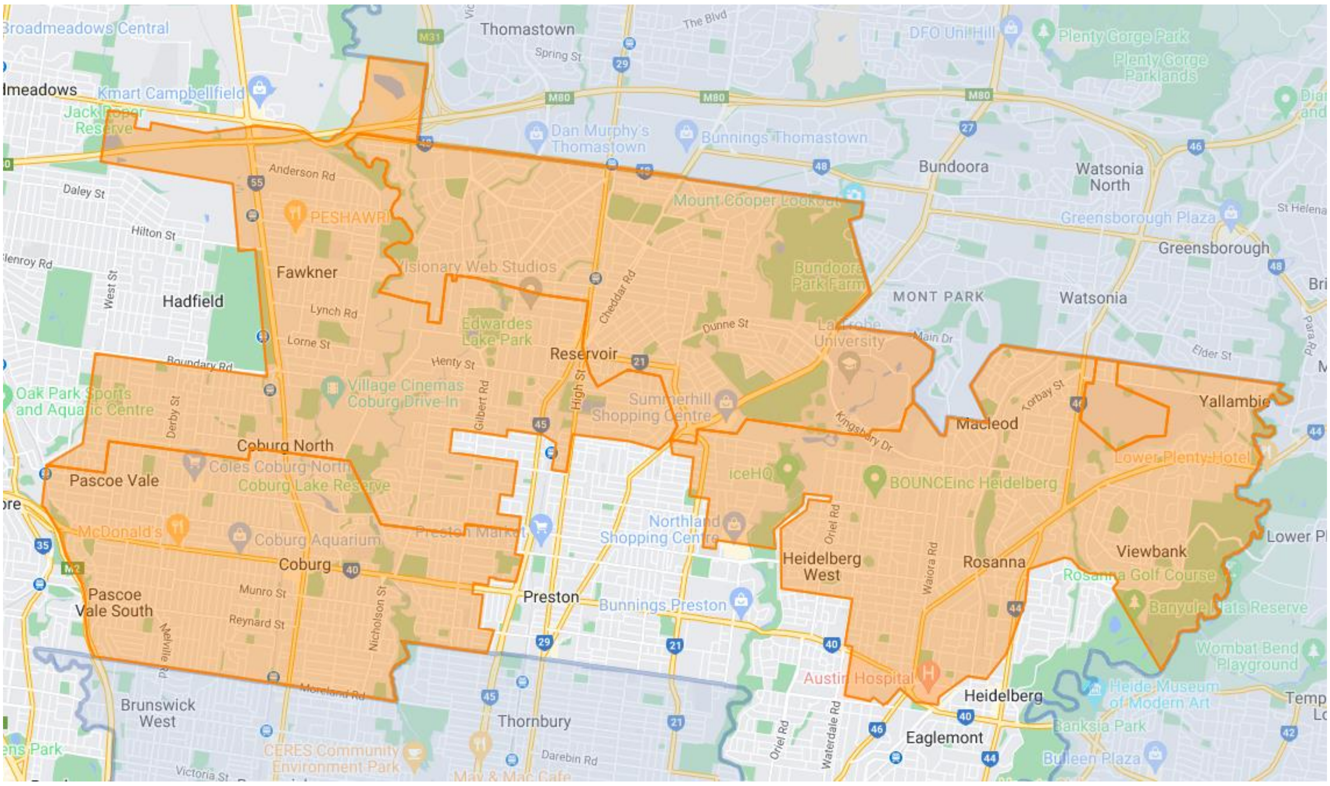
Figure 1-1 NDS Supply Area with the JEN Service Area



1.2 Supply Area Overview

The supply area covering the inner north-western Melbourne metropolitan areas is highly urbanised, with predominantly residential and commercial properties. It includes major precincts for Latrobe University, Reservoir and Coburg.

Figure 1-2 NDS Supply Area



The supply area covers parts of the Darebin, Merri-bek and Banyule city council municipal areas. In 2022, the supply area's population was 219,134. This is forecast to grow to 270,328 residents in 2036. This represents a forecast increase of 23 per cent on the current population (approximately 1.7% per annum).

Table 1-1: Supply Area Resident Population[1]

Suburb	Actual 2022	Actual 2036	Increase	% Increase (pa)
Bundoora - East	9920	10591	671	0.5%
Bundoora - West	6237	7494	1257	1.4%
Coburg - East	12675	19291	**6616**	**3.7%**
Coburg - West	14184	15663	1479	0.7%
Coburg North	8513	10621	2108	1.8%
Fawkner	14184	16653	2469	1.2%
Heidelberg - Rosanna	16202	20322	4120	1.8%
Heidelberg West	15039	21727	**6688**	**3.2%**

[1] See Victorian population data (planning.vic.gov.au)

Suburb	Actual 2022	Actual 2036	Increase	% Increase (pa)
Kingsbury	10549	14304	**3755**	**2.5%**
Pascoe Vale	17402	20549	3147	1.3%
Pascoe Vale South	10463	11955	1492	1.0%
Preston - West	12824	16179	3355	1.9%
Reservoir - North East	14987	18928	3941	1.9%
Reservoir - North West	9881	11090	1209	0.9%
Reservoir - South East	12939	16985	**4046**	**2.2%**
Reservoir - South West	14244	17743	3499	1.8%
Viewbank - Yallambie	18891	20231	1340	0.5%
TOTAL	**219,134**	**270,328**	**51,194**	**1.7%**

The largest percentage increases in population are expected to occur in Coburg East, Heidelberg West, Kingsbury and Reservoir - South East, with the highest growth rate expected in Coburg East and Heidelberg West. Population growth in the supply area is predominantly being accommodated by infill and subdivision of residential developments.

Development in the supply area is governed by the Darebin[2] (central area), Merri-bek[3] (western area), and Banyule[4] (eastern area) City Councils' Planning Schemes as illustrated in Figure 1-3, Figure 1-4 and Figure 1-5 respectively.

[2] See Darebin Planning Scheme - Ordinance

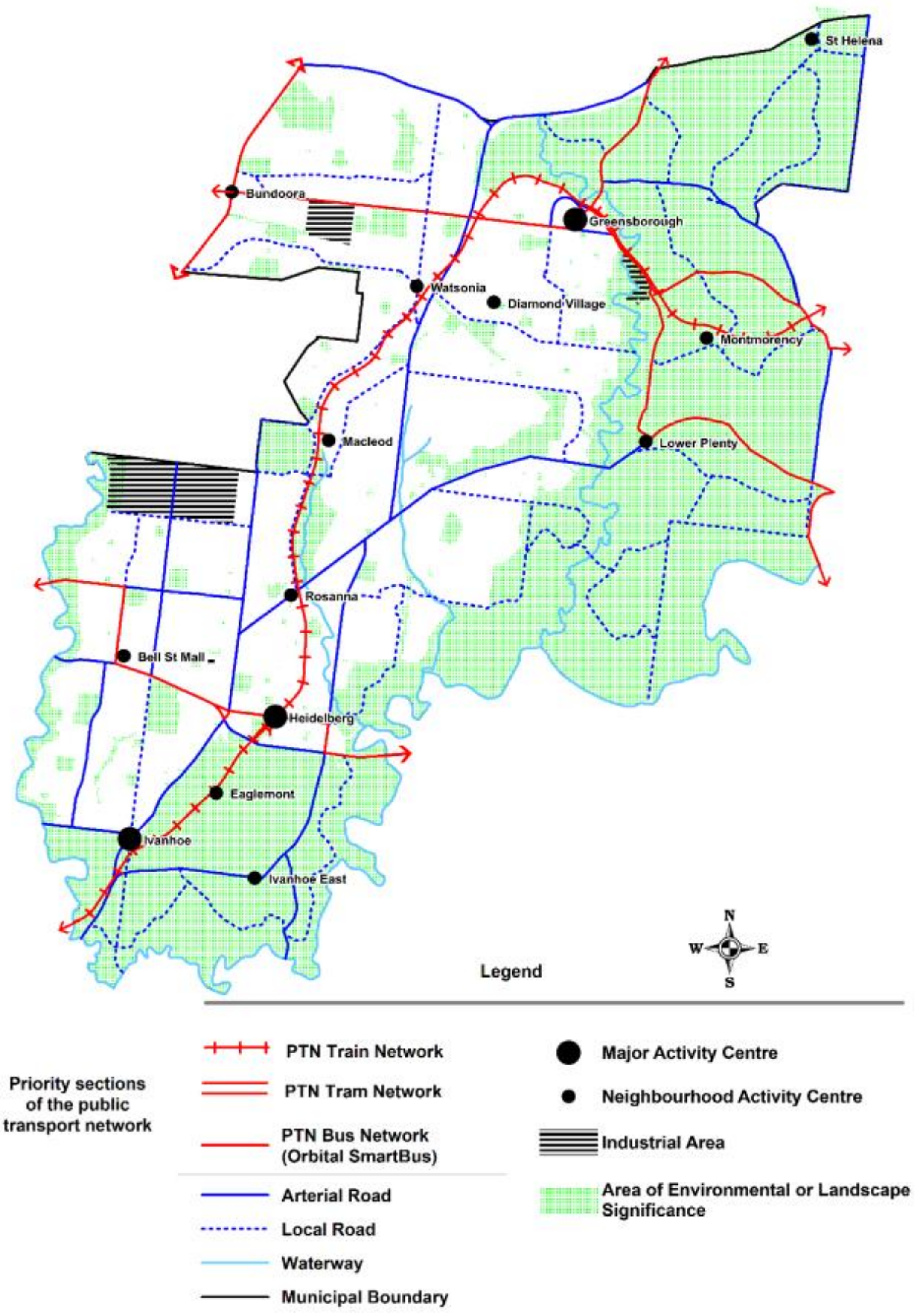
[3] See Merri-bek Planning Scheme - Ordinance

[4] See Banyule Planning Scheme - Ordinance

Figure 1-3: Darebin Planning Scheme strategic framework plan

Source: Darebin Planning Scheme

Figure 1-4: Banyule Planning Scheme strategic framework plan



Source: Banyule Planning Scheme

Figure 1-5: Merri-bek Planning Scheme strategic framework plan

Source: Merri-bek Planning Scheme

The supply area is serviced by our Coburg North (**CN**), Coburg South (**CS**), North Heidelberg (**NH**), as well as JEN feeders supplied by AusNet's Thomastown (**TT**) zone substations by a network of 22 kV distribution feeders. This supply area currently services over 79,885 electricity distribution customers.

Table 1-2: Supply Area Electricity Distribution Customers (by Zone Substation and 22 kV Feeder)[5]

Coburg North (CN) Zone Substation	Actual 2022	Coburg South (CS) Zone Substation	Actual 2022	North Heidelberg (NH) Zone Substation	Actual 2022	Thomastown (TT) Zone Substation	Actual 2022
CN 01	98	CS 02	5850	NH 02	4388	TT 03	3166
CN 02	523	CS 03	2456	NH 03	1555	TT 08	3165
CN 03	1317	CS 05	4979	NH 05	3851	TT 10	4313
CN 04	1528	CS 08	2238	NH 08	2549	TT 11	4819
CN 05	4398	CS 09	1980	NH 09	678		
CN 06	2243	CS 12	2192	NH 12	17		
CN 07	2867	CS 13	1980	NH 13	1		
CN 08	2628			NH 16	2732		
CN 09	70			NH 17	2999		
CN 10	2017			NH 20	2096		
CN 11	4192						
21,881		**21,625**		**20,866**		**15,463**	
79,885							

Growth in population and electrification of transport and gas is expected to contribute to growth in electricity demand. Further growth in electricity demand is expected from a small number of identified major customer developments, such as Latrobe University.[6]

Maximum demand for the supply area is expected to grow on average by 2.7% per annum during the next 10-year period (2025-34).

Parts of the existing sub-transmission network, zone substations and 22 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand. A number of existing assets in the area are already (or forecast to be) highly utilised including one zone substation (being CS), one sub-transmission network (being NH-NEI-NEL-WT), and at least four 22 kV distribution feeders. Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of supply reliability.

[5] Jemena Annual Regulatory Information Notice (RIN) 2021-22, tab 3.6.8.

[6] About the University City of the Future, University City of the Future, La Trobe University.

1.3 Network Overview

The NDS supply area is currently serviced by the following electricity distribution network assets:

- 4 x zone substations
    - 66/22 kV Coburg North Zone Substation (**CN**)
    - 66/22 kV Coburg South Zone Substation (**CS**)
    - 66/22 kV North Heidelberg Zone Substation (**NH**)
    - 66/22 kV Thomastown Zone Substation (**TT**)
- 7 x JEN-owned 66kV sub-transmission lines forming 2 sub-transmission networks from one AusNet transmission terminal substations – Thomastown (**TTS**)
    - TTS-CN-CS-TTS
    - TTS-NEI-NH-NEL-WT-TTS
- 32 x 22 kV distribution feeders (excluding spare feeder circuit breakers)
    - 11 ex CN – CN 01, CN02, CN03, CN04, CN05, CN06, CN07, CN08, CN09, CN10, CN 11.
    - 7 ex CS – CS 02, CS 03, CS 05, CS 08, CS 09, CS 12, CS 13.
    - 10 ex NH – NH 02, NH 03, NH 05, NH08, NH 09, NH 12, NH 13, NH 16, NH 17, NH 20.
    - 4 ex TT – TT 03, TT 08, TT 10, TT 11.

Single line diagrams, network area maps and details of the existing network is provided below.

1.3.1 Zone substation network

The supply boundaries (shaded) of the zone substations contained within the NDS supply area are shown in Figure 1-6, showing the location of the zone substations and their sub-transmission lines (purple).

Figure 1-6 Zone Substation Boundaries

[redacted]

1.3.1.1 Coburg North (CN) zone substation

CN is a fully outdoor summer peaking zone substation having two 66/22 kV 30 MVA and one 66/22 kV 33 MVA transformers. Under system normal conditions, the zone sub is a split bus meaning, two transformers are operated in parallel as one group and the third is independent however can be switched. Each transformer is fully switched into a looped 66 kV sub-transmission network from TTS. CN has eleven in-service 22 kV feeders and no spare 22 kV circuit breakers for additional future feeders, across the three existing 22 kV buses.

Within the NDS supply area, CN services the suburbs of Coburg North, Fawkner, Reservoir and parts of Preston, supplying 21,881 customers. The single line diagram and aerial view of CN is shown in Figure 1-7 and Figure 1-8 respectively.

Figure 1-7 CN Single Line Diagram

[redacted]

Figure 1-8 CN Aerial View

1.3.1.2 Coburg South (CS) zone substation

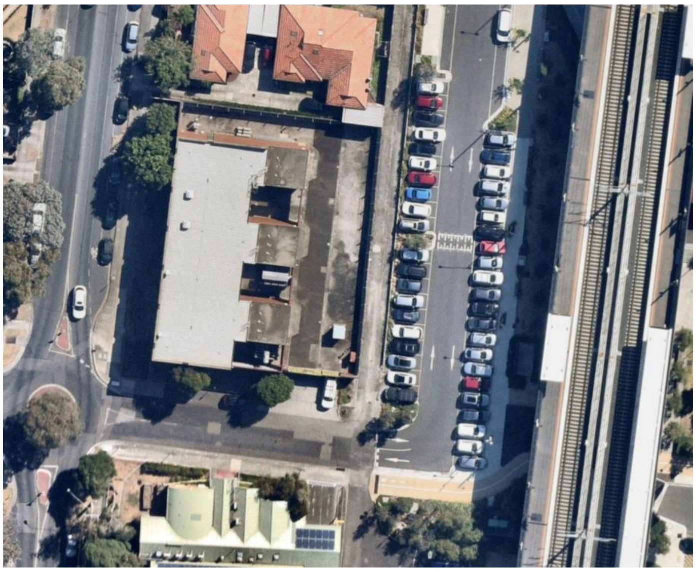
CS is a fully indoor summer peaking zone substation having two 66/22 kV 30 MVA transformers. Under system normal conditions, two transformers are operated in parallel as one group. Each transformer is fully switched into a looped 66 kV sub-transmission network from TTS. CS has the ability to expand to three transformers in future. CS has seven in-service 22 kV feeders and no spare 22 kV circuit breakers for additional future feeders, across the two existing 22 kV buses.

Within the NDS supply area, CS services the suburb of Coburg, Coburg East and parts of Moreland, Pascoe Vale and Pascoe Vale South, supplying 21,675 customers. Figure 1-9 and Figure 1-10 show the single line diagram and aerial view of CS, respectively.

Figure 1-9 CS Single Line Diagram

[redacted]

Figure 1-10 CS Aerial View



1.3.1.3 North Heidelberg (NH) zone substation

NH has two 66/22 kV 30 MVA and one 66/22 kV 33 MVA transformers and is a summer peaking semi-indoor zone substation. Under system normal conditions, the three transformers are operated in parallel as one group. Each transformer is fully switched into a looped 66 kV sub-transmission network from TTS. NH has the ability to expand to four transformers in future. NH has ten in-service 22 kV feeders and two spare 22 kV circuit breakers for additional future feeders (NH 18, NH 19), across the three existing 22 kV buses (with all spares being on the No.3 22 kV bus).

Within the NDS supply area, NH services the suburbs of Heidelberg West, Heidelberg Heights, Rosanna, Macleod and Viewbank supplying 20,866 customers. Figure 1-11 and Figure 1-12 show the single line diagram and aerial view of NH, respectively.

Figure 1-11 NH Single Line Diagram

[redacted]

Figure 1-12 NH Aerial View

1.3.1.4 Thomastown (TT) zone substation

TT is an AusNet-owned zone substation located adjacent to Thomastown Terminal Station (**TTS**). As the owner of this zone substation, AusNet has planning responsibility and plans to redevelop this zone substation within the next 10 years. JEN takes supply from TT via four 22 kV distribution feeders (TT 03, TT 08, TT 10 and TT 11). JEN has planning responsibility for these distribution feeders.

Within the NDS supply area, TT services the JEN suburbs of Reservoir, Thomastown, Kingsbury and Bundoora supplying 15,463 JEN customers.

1.3.2 Sub-transmission network

Three sub-transmission networks service the area, all three at 66 kV from TTS as shown in Figure 1-13.

Figure 1-13: 66kV Sub-transmission Lines in the Supply Area - Schematic

[redacted]

1.3.2.1 TTS-CN-CS-TTS

The TTS-CN-CS-TTS 66 kV sub-transmission network supplies approximately 43,556 customers via the CN and CS 66/22 kV zone substation from two 66 kV lines from TTS connected in a loop. Figure 1-14 shows the schematic diagram of this network.

Figure 1-14: TTS-CN-CS 66 kV Sub-transmission Network

[redacted]

1.3.2.2 TTS-NEI-NH-NEL-WT-TTS

The TTS-NEI-NH-NEL-WT-TTS 66 kV sub-transmission network supplies approximately 36,329 JEN customers via the NH and WT 66/22 kV zone substation and two major customer zone substations from two 66 kV lines from TTS connected in a loop with NEI teed off the TTS-NEI-NH 66 kV line. Figure 1-15 shows the schematic diagram of this network.

Figure 1-15: TTS-NEI-NH-NEL-WT-TTS 66kV Sub-transmission Loop

[redacted]

1.3.3 HV distribution feeder network

JEN's 22 kV distribution feeder network for the NDS supply area is illustrated schematically in Figure 1-16.

Multiple 22 kV inter-feeder tie points exist between CN, CS, NH, TT, (via feeders CN 01, CN 02, CN 05, CN 08, CN 09, CN 11, CS 02, CS 03, CS 08, CS 12, CS 13, NH 16, TT 08, TT 10).

Figure 1-16 22kV Distribution Feeders

[redacted]

2. Identified Need

There is one key driver for an asset management intervention within the NDS supply area. This driver relates to existing and emerging asset utilisation limitations associated with maximum demand growth, reducing the spare capacity available within the distribution network.

2.1 Network Utilisation

Maximum demand for the supply area is expected to grow on average by 2.7% per annum during the next 10-year period (2025-34) based on underlying growth within the distribution network. The expected increase in maximum demand is mainly driven by population growth from residential infill and high-rise apartment development, and increased electric vehicle usage and electrification of gas across the area, with some major customer developments. Parts of the existing sub-transmission network, zone substations and 22 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand. A number of existing assets in the area are forecast to be highly utilised including at least four 22 kV distribution feeders. Staged, targeted augmentations of the network are needed, to connect new customers and maintain current levels of supply reliability.

2.1.1 Network Ratings

This section details the network capacity ratings that are available for customers to use during system normal (**N**) conditions and single contingency (**N-1**) conditions with one network asset out of service (forced or planned outage), for summer (worst case) and winter (best case) seasons. Table 2-1 present the ratings of zone substations servicing the supply area.

Table 2-1: Zone Substation Ratings (MVA)

Zone Substation	Summer (N)	Winter (N)	Summer (N-1)	Winter (N-1)
CN	93.0	93.0	72.5	83.6
CS	60.0	60.0	42.2	47.3
NH	93.0	93.0	75.2	76.0
TT	84.0	84.0	58.6	68.4

Table 2-2 present the ratings of sub-transmission lines servicing the supply area.

Table 2-2: Sub-transmission Ratings (MVA)

Sub-transmission Network	Summer	Winter	Line Section
TTS-CN-CS-TTS	**187.0**	**202.0**	**Overall N Rating**
	117.2	**126.3**	**Overall N-1 Rating**
	117.2	126.3	TTS-CN
	117.2	126.3	TTS-CS
	80.0	80.0	CN-CS

Sub-transmission Network	Summer	Winter	Line Section
TTS-NH-NEI-NEL-WT-TTS	**180.0**	**190.0**	**Overall N Rating**
	117.2	**126.3**	**Overall N-1 Rating**
	117.2	126.3	TTS-NEI
	117.2	126.3	TTS-WT
	117.2	126.3	NEI-NH
	90.3	96.6	NH-NEL
	90.3	96.6	NEL-WT

Table 2-3 presents the ratings of 22 kV distribution feeders servicing the NDS supply area.

Table 2-3: 22kV Distribution Feeder Ratings (MVA)

Feeder	Summer	Winter	Feeder	Summer	Winter
CN 01	12.4	12.4	CS 12	12.4	12.4
CN 02	22.5	22.5	CS 13	12.4	12.4
CN 03	12.4	12.4	NH 02	14.3	14.3
CN 04	13.1	13.1	NH 03	10.9	10.9
CN 05	14.3	14.3	NH 05	10.9	10.9
CN 06	13.1	13.1	NH 08	8.2	8.2
CN 07	11.8	11.8	NH 09	14.3	14.3
CN 08	14.3	14.3	NH 12	14.3	14.3
CN 09	12.4	12.4	NH 13	15.1	15.1
CN 10	14.3	14.3	NH 16	9.0	9.0
CN 11	14.3	14.3	NH 17	13.1	13.1
CS 02	13.5	13.5	NH 20	22.5	22.5
CS 03	12.4	12.4	TT 03	14.3	14.3
CS 05	12.4	12.4	TT 08	12.4	12.4
CS 08	12.6	12.6	TT 10	12.4	12.4
CS 09	12.4	12.4	TT 11	12.4	12.4

2.1.2 Historical Maximum Demand

Table 2-4 presents the historical actual summer maximum demand on our zone substation and sub-transmission assets in the area. Values highlighted in red exceed the (N-1) cyclic rating and **bold red** exceed the (N) rating, noting that the ambient temperature in summer 2021 was mild (and hence an abnormally low maximum demand) summer.

Table 2-4: Actual Historical Summer Maximum Demand (MVA)

Network Asset	N Rating	N-1 Rating	2020	2021	2022	2023
CN	**93.0**	**72.5**	68.0	47.6	48.3	51.0
CS	**60.0**	**42.2**	50.0	41.1	42.7	44.5
TTS-CN-CS-TTS	**187.0**	**117.2**	118.1	88.6	91.0	95.5
NH	**93.0**	**75.2**	65.6	57.9	58.6	60.6
TTS-NEI-NH-NEL-WT-TTS	**180.0**	**117.2**	139.0	122.0	118.9	124.6
TT	**84.0**	**58.6**	80.2	68.2	71.9	73.6

This table illustrates that TT, and CS have historically been highly utilised zone substations, and TTS-CN-CS and TTS-NEI-NH-NEL-WT-TTS highly utilised sub-transmission network. Since the commissioning of Preston (PTN) zone substation in 2020, transfers were completed prior to summer 2021 to reduce the maximum demand on TTS-CN-CS-TTS.

Table 2-5 presents the historical actual summer maximum demand on our 22 kV distribution feeder assets in the area. Values highlighted **bold red** exceed the (N) rating.

Table 2-5: Distribution Feeder Actual Historical Summer Maximum Demand (MVA)

Feeder	Rating	2020	2021	2022	2023	Feeder	Rating	2020	2021	2022	2023
CN 01	**12.4**	7.0	7.0	7.4	7.2	**CS 12**	**12.4**	9.2	6.2	5.8	6.3
CN 02	**22.5**	5.3	4.5	5.2	4.9	**CS 13**	**12.4**	3.7	3.7	3.8	4.5
CN 03	**12.4**	4.1	3.3	3.0	3.3	**NH 02**	**14.3**	14.4	11.8	13.9	13.1
CN 04	**13.1**	4.9	4.1	4.0	4.0	**NH 03**	**10.9**	6.0	5.3	5.4	5.4
CN 05	**14.3**	9.0	9.2	7.7	8.9	**NH 05**	**10.9**	6.4	4.8	5.5	5.7
CN 06	**13.1**	6.3	5.7	6.3	5.8	**NH 08**	**8.2**	6.4	5.5	4.6	4.7
CN 07	**11.8**	9.4	3.6	4.1	4.1	**NH 09**	**14.3**	6.4	6.1	6.5	6.4
CN 08	**14.3**	8.1	3.7	4.1	4.1	**NH 12**	**14.3**	6.1	5.3	6.2	5.8
CN 09	**12.4**	4.5	4.0	4.2	3.9	**NH 13**	**15.1**	8.8	8.9	9.0	8.5

Feeder	Rating	2020	2021	2022	2023	Feeder	Rating	2020	2021	2022	2023
CN 10	**14.3**	6.7	5.2	5.8	5.8	**NH 16**	**9.0**	7.6	7.0	6.7	7.7
CN 11	**14.3**	7.7	6.2	8.6	7.4	**NH 17**	**13.1**	9.3	9.1	9.6	9.2
CS 02	**13.5**	11.7	9.0	10.1	10.6	**NH 20**	**22.5**	5.5	4.3	4.5	5.4
CS 03	**12.4**	9.6	4.8	4.8	5.2	**TT 03**	**14.3**	10.8	7.8	8.4	9.6
CS 05	**12.4**	10.1	8.5	8.8	9.1	**TT 08**	**12.4**	8.2	7.6	8.0	8.4
CS 08	**12.6**	8.7	4.2	4.0	4.2	**TT 10**	**12.4**	9.0	7.5	8.5	8.6
CS 09	**12.4**	4.7	3.6	4.0	3.9	**TT 11**	**12.4**	6.6	5.5	6.1	5.8

2.1.3 Maximum Demand Forecast

This section presents the maximum demand forecast over the next 10-years for the NDS supply area, taking into account new loads, underlying growth and the impacts of CER. The maximum demand forecasts are developed under different ambient temperature conditions, designated by a Probability of Exceedance (**PoE**), using internally prepared bottom-up forecasts which are reconciled to externally prepared top-down econometric forecasts.

Table 2-6 presents the 10% PoE summer maximum demand forecast for the forward 10-year planning period. Values highlighted and are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating. TTS-CN-CS-TTS, TTS-NEI-NH-NEL-WT-TTS, CS and TT are at risk of overload over the planning horizon.

Table 2-6: 10% PoE Summer Maximum Demand Forecast (MVA) - Do Nothing

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CN	**93.0**	**72.5**	59.7	62.9	65.8	67.6	68.6	69.4	70.4	71.2	72.1	72.8
CS	**60.0**	**42.2**	51.3	52.7	54.1	55.3	56.0	56.9	58.0	59.1	**60.2**	**61.0**
TTS-CN-CS	**187.0**	**117.2**	111.0	115.6	119.9	122.9	124.6	126.3	128.4	130.3	132.3	133.8
NH	**93.0**	**75.2**	54.8	50.5	51.6	52.4	52.7	53.6	54.5	55.5	56.5	57.2
TTS-NEI-NH-NEL-WT	**180.0**	**117.2**	130.7	132.4	136.4	139.1	140.4	145.7	161.7	163.5	167.0	170.3
TT	**84.0**	**58.6**	**88.6**	**90.4**	**92.5**	**94.8**	**97.1**	**99.4**	**101.7**	**104**	**106.3**	**108.6**

Table 2-7 presents the 10% PoE winter maximum demand forecast for the forward 10-year planning period. Values highlighted and are an identified network limitation with red exceeding the (N-1) rating and **bold red** exceeding the (N) rating. TTS-NEI-NH-NEL-WT-TTS, CS and TT are at risk of overload over the planning horizon.

Table 2-7: 10% PoE Winter Maximum Demand Forecast (MVA) - Do Nothing

Network Asset	N Rating	N-1 Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CN	**93.0**	**83.6**	52.9	57.5	61.4	63.9	65.6	66.6	67.5	68.5	69.5	70.6
CS	**60.0**	**47.3**	42.7	45.2	47.5	49.3	50.6	51.8	53.0	54.1	55.3	56.4
TTS-CN-CS	**202.0**	**126.3**	95.6	102.6	108.9	113.2	116.2	118.5	120.5	122.6	124.8	127.0
NH	**93.0**	**76.0**	44.7	41.7	43.6	44.7	45.5	46.5	47.4	48.3	49.1	50.0
TTS-NEI-NH-NEL-WT	**190.0**	**126.3**	103.6	106.3	111.4	114.5	116.6	121.6	135.8	137.7	141.1	144.7
TT	**84.0**	**68.4**	70.1	72	74.3	76.9	79.5	82.1	**84.7**	**87.3**	**89.9**	**92.5**

Table 2-8 presents the distribution feeder 10% PoE summer maximum demand forecast for the forward 10-year planning period. Values highlighted **bold red** exceed 100% of the rating (i.e., exceed the N rating) and are an identified network limitation. Some distribution feeders are at risk of overload over the planning horizon, particularly NH 02 in summer 2026, TT 10 in summer 2027, and CS 05 in summer 2033.

Table 2-8: Distribution Feeder 10% PoE Summer Maximum Demand Forecast (MVA) - Do Nothing

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CN 01	**12.4**	7.2	7.2	7.3	7.4	7.4	7.5	7.6	7.7	7.8	7.9
CN 02	**22.5**	7.6	9.2	10.2	10.3	10.3	10.5	10.6	10.7	10.9	11.0
CN 03	**12.4**	4.5	5.5	5.5	5.5	5.5	5.6	5.7	5.7	5.8	5.9
CN 04	**13.1**	5.4	5.4	5.4	5.4	5.5	5.5	5.6	5.7	5.8	5.8
CN 05	**14.3**	11.7	11.9	12.2	12.5	12.6	12.7	12.9	13.1	13.3	13.4
CN 06	**13.1**	6.0	7.0	8.4	9.3	10.3	10.4	10.5	10.7	10.8	10.9
CN 07	**11.8**	4.7	4.9	5.2	5.3	5.4	5.5	5.5	5.6	5.7	5.7
CN 08	**14.3**	5.3	5.7	5.8	5.8	5.9	5.9	6.0	6.1	6.2	6.2
CN 09	**12.4**	4.0	4.4	4.8	5.2	5.2	5.3	5.4	5.4	5.5	5.6
CN 10	**14.3**	6.4	6.8	7.2	7.3	7.3	7.4	7.5	7.6	7.7	7.8
CN 11	**14.3**	8.6	9.5	10.9	11.9	12.3	12.4	12.6	12.8	12.9	13.1
CS 02	**13.5**	12.0	12.1	12.2	12.3	12.4	12.6	12.8	13.0	13.3	13.5
CS 03	**12.4**	6.3	7.1	7.9	8.4	8.7	9.0	9.1	9.3	9.5	9.6
CS 05	**12.4**	11.0	11.5	11.6	11.7	11.8	12.0	12.2	12.4	**12.7**	**12.8**

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CS 08	**12.6**	4.5	4.6	4.7	4.8	4.8	4.9	5.0	5.1	5.2	5.2
CS 09	**12.4**	4.1	4.8	5.9	6.8	7.1	7.3	7.5	7.6	7.8	7.9
CS 12	**12.4**	6.9	7.1	7.1	7.1	7.2	7.3	7.4	7.6	7.7	7.8
CS 13	**12.4**	5.4	5.6	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.5
NH 02	**14.3**	14.2	**14.5**	**14.7**	**14.8**	**14.9**	**15.1**	**15.3**	**15.5**	**15.7**	**15.9**
NH 03	**10.9**	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3
NH 05	**10.9**	2.0	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.1	2.1
NH 08	**8.2**	5.1	5.1	5.1	5.1	5.1	5.2	5.3	5.4	5.5	5.6
NH 09	**14.3**	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
NH 12	**14.3**	8.1	9.6	10.3	11.0	11.1	11.2	11.4	11.7	11.9	12.0
NH 13	**15.1**	9.2	9.1	9.1	9.2	9.2	9.4	9.5	9.7	9.9	10.0
NH 16[7]	**9.0**	7.6	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
NH 17	**13.1**	10.1	10.6	11.1	11.2	11.4	11.6	11.8	12.0	12.2	12.4
NH 20	**22.5**	6.1	7.1	8.0	8.3	8.3	8.4	8.6	8.8	8.9	9.0
TT 03	**14.3**	10.2	10.3	10.4	10.5	10.5	10.7	10.9	11.1	11.3	11.4
TT 08	**12.4**	9.0	9.9	10.8	11.2	11.3	11.5	11.7	11.9	12.1	12.3
TT 10	**12.4**	11.2	12.1	**12.8**	**12.8**	**12.9**	**13.1**	**13.4**	**13.6**	**13.8**	**14.0**
TT 11	**12.4**	6.9	6.9	6.9	7.0	7.1	7.2	7.3	7.4	7.6	7.7

Table 2-9 presents the distribution feeder 10% PoE winter maximum demand forecast for the forward 10-year planning period. Values highlighted in **bold red** exceed 100% of the rating (i.e., exceed the N rating) and are an identified network limitation. Some distribution feeders are at risk of overload over the planning horizon, particularly NH 02 in winter 2027, and CN 06 in winter 2031.

Table 2-9: Distribution Feeder 10% PoE Winter Maximum Demand Forecast (MVA) - Do Nothing

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CN 01	**12.4**	8.2	8.4	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.3
CN 02	**22.5**	8.1	10.0	11.2	11.4	11.5	11.6	11.8	11.9	12.0	12.2
CN 03	**12.4**	5.0	6.3	6.4	6.5	6.6	6.7	6.8	6.9	7.0	7.2
CN 04	**13.1**	4.8	5.0	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.6
CN 05	**14.3**	7.0	7.3	7.6	7.9	8.1	8.2	8.4	8.5	8.6	8.8
CN 06	**13.1**	6.9	8.3	10.2	11.5	12.8	13.0	**13.2**	**13.4**	**13.6**	**13.9**
CN 07	**11.8**	5.1	5.5	6.0	6.2	6.3	6.5	6.6	6.7	6.8	6.9

7 Planned load transfer away from NH16 for customer load connections on the TTS-NEI-NH-NEL-WT-TTS sub-transmission network

Feeder	Rating	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CN 08	**14.3**	5.4	6.0	6.2	6.3	6.4	6.5	6.6	6.7	6.9	7.0
CN 09	**12.4**	4.4	4.8	5.4	5.9	6.0	6.0	6.1	6.2	6.2	6.3
CN 10	**14.3**	5.6	6.1	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.4
CN 11	**14.3**	8.7	9.9	11.6	12.8	13.4	13.6	13.9	14.1	14.3	**14.6**
CS 02	**13.5**	9.1	9.4	9.7	9.9	10.1	10.3	10.6	10.8	11.0	11.3
CS 03	**12.4**	5.2	6.1	6.9	7.4	7.7	8.0	8.2	8.4	8.6	8.7
CS 05	**12.4**	8.5	9.1	9.4	9.6	9.7	10.0	10.2	10.4	10.6	10.8
CS 08	**12.6**	3.8	4.0	4.2	4.4	4.5	4.6	4.7	4.8	4.9	5.0
CS 09	**12.4**	4.3	5.2	6.5	7.7	8.1	8.4	8.6	8.8	9.0	9.2
CS 12	**12.4**	6.5	6.9	7.0	7.1	7.3	7.4	7.6	7.8	7.9	8.1
CS 13	**12.4**	5.5	5.8	6.2	6.4	6.5	6.6	6.8	6.9	7.1	7.2
NH 02	**14.3**	13.2	13.9	**14.4**	**14.7**	**14.9**	**15.2**	**15.5**	**15.7**	**16.0**	**16.3**
NH 03	**10.9**	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9
NH 05	**10.9**	1.3	1.3	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.6
NH 08	**8.2**	4.2	4.3	4.4	4.5	4.6	4.7	4.8	4.9	4.9	5.0
NH 09	**14.3**	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
NH 12	**14.3**	6.4	7.8	8.5	9.1	9.2	9.3	9.5	9.6	9.8	9.9
NH 13	**15.1**	7.7	7.7	7.7	7.7	7.8	7.8	7.8	7.9	7.9	7.9
NH 16	**9.0**	6.3	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9
NH 17	**13.1**	9.9	10.6	11.3	11.6	11.9	12.2	12.5	12.7	13.0	**13.3**
NH 20	**22.5**	4.9	5.9	6.8	7.1	7.3	7.4	7.6	7.7	7.9	8.1
TT 03	**14.3**	8.1	8.5	8.7	8.9	9.2	9.5	9.7	9.9	10.1	10.3
TT 08	**12.4**	6.7	7.5	8.4	8.9	9.2	9.5	9.7	9.9	10.1	10.3
TT 10	**12.4**	12.0	13.3	14.3	14.5	14.8	15.1	15.4	15.8	16.1	16.4
TT 11	**12.4**	7.1	7.2	7.4	7.6	7.8	7.9	8.1	8.3	8.4	8.6

2.2 Summary of Network Limitations

This NDS will assess the technical and economic viability of solutions to alleviate the network utilisation issues identified above. A summary of credible solutions is presented in Table 2-10 that could address each of the identified limitations. Further details and diagrams of the scope of the solutions is provided in the Appendices.

Table 2-10: Summary of identified network limitations and possible options

Network Asset	Limitation	From	Possible screening of network options to address the need[7]
TTS-NEI-NH-NEL-WT-TTS	N-1 capacity N secure[8]	Existing 2030	Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop Augment TTS-NEI-NH-NEL-WT-TTS BESS and/or demand management in NH, WT or NEL 22 kV distribution networks
TT-CN-CS-TTS	N-1 capacity	2027	Augment TTS-CN-CS-TTS BESS and/or demand management in CN or CS 22kV distribution networks
CS	N-1 capacity	Existing	Augment CS BESS and/or demand management in CS 22 kV distribution network
TT 10	N capacity	2027	Augment feeder TT0-011 BESS and/or demand management in TT 10 22 kV distribution network
CS 05	N capacity	2033	Augment feeder CS0-005 BESS and/or demand management in CS 05 22 kV distribution network
CN 06	N capacity	2031	Load transfers from CN 06 to CN 04 and CN 10
NH 02	N capacity	2026	Augment section of NH0-002 BESS and/or demand management in NH 02 22 kV distribution network

The effectiveness of each solution to address an identified need is evaluated within this NDS by comparing its costs and benefits against the status quo (do nothing), used as a reference base case. Where multiple potential solutions are indicated above to address an identified limitation, those solutions are separated into different options in this NDS for further comparative technical and economic evaluation.

[8] Pre-=contingent load shedding is required when the loop loading is above 120% of its N-1 rating.

2.3 Non-network alternatives

The NER requires us to consider non-network and standalone power systems (SAPS) solutions for addressing identified limitations on our network. In developing this NDS, we have considered the possibility of credible non-network or SAPS solutions, for meeting each of the existing and emerging network capacity limitations identified within the supply area.

Non-network and SAPS solutions could be delivered through embedded generation, storage, or demand-side management programs (or combination thereof), to defer or reduce in scope, traditional network augmentation solutions. Such solutions need to have a sufficient number of proponents participating, to provide the aggregate level of dispatchable capacity needed, to defer an augmentation by at least one year. This could then address the identified capacity limitations, and avoid supply interruptions or asset overload damage which may otherwise result without adequate network support.

Demand management solutions are targeted at reducing the peak demand by reducing customer load. This includes solutions such as direct load control (including for example, air-conditioning, pool pumps and electric vehicle charging), or customer behavioural demand response programs. By comparison, embedded generation and/or storage solutions are targeted at supplying the peak demand by offsetting part of the customers' load using local generation sources. This includes dispatchable blocks of embedded generators and/or energy storage systems (including for example, virtual power plants, community storage, standby/grid connected generation).

The aim when defining potential credible non-network and SAPS options, is to test whether non-network or SAPS solutions (or combination of) is a viable way to avoid or reduce the scale of a network investment, in a way that efficiently addresses the identified need. The criteria we use to assess the potential credibility of non-network or SAPS solutions includes:

- **Addressing the identified need**: being able to reduce or eliminate the supply reliability risk (EUE) associated with the identified need.
- **Technically feasible**: there being no constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or potentially better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

We intend to pursue a blend of prudent, targeted investments in network and non-network solutions to reduce EUE within the NDS supply area, consistent with NER clause 6.5.7. This approach provides us with greater option value (in some cases) to manage uncertainty in our forecasts of maximum demand growth. As such, for each of the major solutions identified in the preferred network development plan of this NDS, we intend to consult the market (through the RIT-D process) to identify credible non-network or SAPS solutions.

Given the needs for non-network solutions for this NDS are known, we are yet to identify (from the market) credible non-network solutions for each limitation. We intend to fund any identified preferred option non-network solutions through capex to opex substitution during the regulatory control period, rather than request step changes to our operational expenditure regulatory allowance.

Notwithstanding our approach to seeking efficient solutions to project augmentation, we have undertaken a high-level assessment of non-network options by considering the benefits of deferring expenditure by one year against a plausible alternative of procuring capacity from the market based on recent RIT-D responses. Applying this methodology to distributed storage solutions, we determined that the installed costs[9] of $475 million[10] is greater than the $15.2 million installed costs of the preferred network option. Furthermore, applying this methodology to the lowest-cost demand response solution, we determined that the costs of $9.7 million pa[11] is also greater than

[9] Table B.8 "Storage current cost data by source, total cost basis", from the CSIRO 2023-24 GenCost Report, located at https://www.csiro.au/en/research/technology-space/energy/GenCost.

[10] Installed cost of $500/kWh x $911 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $475 million.

[11] Dispatch cost of $10/kWh x $911 million present value reliability benefit ÷ $47.905/kWh VCR ÷ 20 years analysis period = $9.5 million pa plus $0.2 million pa of ongoing costs.

the network augmentation deferral benefit of $0.85 million pa[12]. Therefore, the non-network options are not the preferred approach based on program-wide network benefits alone.

2.4 Consumer Energy Resources

Decentralisation, digitisation, decarbonisation and electrification are fundamentally changing the structure and function of the electricity system. Our network will need to continue to evolve from a network which provides one-directional flow to the crucial platform which underpins energy use in our network area.

Given the expanded role of our network – in terms of scale, function and criticality – we are keen ensure we also take advantage of the available opportunities to make the most of our existing network before building more.

A key aspect of this is our Consumer Energy Resources (CER) Strategy which includes:

- **Modernising the grid** – enable and support the uptake of CER on the network, including flexible services using Dynamic Operating Envelopes (**DOE**) to remove static export and import limits, reduce CER curtailment, improve CER exports, and improve voltage, supply quality and system security compliance.
- **Seeding the market** – stimulate growth in the efficient use of CER to support the broader market, including data visibility for customers, enhanced tariffs such as for solar soak and EV charging, and use common communication protocols to support CER aggregation by market service providers.

Our demand forecast is premised on the roll-out of our CER strategy. For example, it takes into account the continued impact of solar in reducing peak demand (until the peak demand shifts later in the evening) and moderates the impact of EV charging overtime, based on expected roll-out of cost-reflective tariffs and consumers who opt-into forms of managed charging. Or put another way, the network constraints identified already incorporate the impact of our CER strategy.

This strategy also considers a sensitivity where our CER strategy is more effective than anticipated (all EV charging load is removed from our demand forecast). This sensitivity shows the impact of what could occur if all EV charging was subject to dynamic operating envelopes, considered as part of our CER strategy.

[12] Preferred network option cost of 16.4 million present value of capital and O&M costs x 5.18% discount rate = $0.85 million pa.

3. Assessment Methodology and Assumptions

This section outlines the method that we apply in assessing its network risks and limitations for each credible solution and of the feasible options. It presents key assumptions and input information applied to the assessments in this document.

3.1 Probabilistic Planning

In accordance with clause 5.17.1(b) of the National Electricity Rules, our augmentation investment decisions are aligned with the Regulatory Investment Test for Distribution (RIT-D). This test aims to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

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

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

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

3.2 Assessment Assumptions

In evaluating net economic benefits, the following assumptions are used to calculate the annualised value of EUE for all the solutions and options analysed in this document:

- Value of Customer Reliability (VCR) of $47,905 per MWh (real, 2024).
- Average feeder outage rate is calculated based on recent years of JEN's actual historic reliability data.
- Sub-transmission line outage frequency, which is 0.09 outages per kilometre of line length per year.
- Sub-transmission line outage average duration of 4 hours per outage.
- Power transformer outage frequency, which is 0.01 outages per year.
- Power transformer outage average duration of 2.65 months per outage.
- Regulatory discount rate of 5.18%.
- O&M of 1.0% of the capital cost per annum.
- Economic analysis period for cost-benefit analysis set at 20 years.
- Distribution feeder EUE based on 6-year demand forecast, held constant thereafter.
- Zone substation and sub-transmission EUE based on 10-year demand forecast, held constant thereafter; and
- 70% weighting on 50% PoE, and 30% weighting on 10% PoE for calculation of the EUE.

4. Base Case

The base case Option 1 (do nothing) assumes no additional investment into the network to address the existing and forecast network limitations identified in section 2.2.

Table 4-1 details the zone substation and sub-transmission EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-1: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 1

Asset	CS	TTS-CN-CS-TTS	TTS-NEI-NH-NEL-WT-TTS[13]	Total
2025	0.1	0.0	0.1	**0.2**
2026	0.3	0.0	0.3	**0.6**
2027	0.5	0.0	440.0	**440.5**
2028	0.6	0.0	337.1	**337.8**
2029	0.7	0.0	722.5	**723**
2030	0.9	0.0	1,394	**1,395**
2031	1.2	0.0	1,500	**1,501**
2032	1.7	0.0	1,500	**1,502**
2033	2.3	0.0	1,500	**1,502**
2034	3.5	0.1	1,500	**1,504**

Table 4-2 details the distribution feeder EUE for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-2: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 1

Asset	CS 05	NH 02	TT 10	Total
2025	0.0	0.0	0.0	**0.0**
2026	5.3	0.1	1.2	**6.6**
2027	9.6	0.4	6.1	**16.1**
2028	13.2	0.6	7.7	**21.6**
2029	14.9	0.9	9.7	**25.5**
2030	16.8	1.8	12.4	**31.0**
2031	18.4	3.1	15.6	**37.0**
2032	20.0	4.4	18.7	**43.1**
2033	21.5	5.7	21.9	**49.1**
2034	23.1	7.0	25.1	**55.2**

[13] Includes the moderated forecast major customer block loads, and operation of the loop to the N secure rating.

Applying the VCR, gives the values of the expected EUE over the forecast period.

Table 4-3 details the zone substation and sub-transmission EUE financial value for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-3: Zone Substation and Sub-transmission Value of Expected Unserved Energy ($k, Real 2024) – Option 1

Asset	CS	TTS-CN-CS-TTS	TTS-NEI-NH-NEL-WT-TTS	Total
2025	4	0	7	**11**
2026	15	0	13	**29**
2027	22	0	21,078	**21,100**
2028	30	0	16,150	**16,180**
2029	35	0	34,612	**34,647**
2030	45	1	66,776	**66,822**
2031	59	1	71,858	**71,918**
2032	80	1	71,858	**71,938**
2033	109	2	71,858	**71,968**
2034	165	3	71,858	**72,026**

Table 4-4 details the distribution feeder EUE financial value for Option 1 (do nothing) over the planning horizon for the identified network limitations.

Table 4-4: Distribution Feeder Value of Expected Unserved Energy ($k, Real 2024) – Option 1

Asset	CS 05	NH 02	TT 10	Total
2025	0	0	0	**0**
2026	254	6	57	**317**
2027	462	20	291	**773**
2028	634	29	371	**1,033**
2029	715	42	466	**1,223**
2030	806	85	594	**1,484**
2031	881	147	746	**1,774**
2032	957	210	898	**2,064**
2033	1,032	272	1,050	**2,354**
2034	1,107	335	1,202	**2,644**

5. Options Analysis

5.1 Options Description and Scope

This section provides a summary of the solutions which combine to form the projects for each network development option that are designed to address the identified needs.

Table 5-1 provides a broad description of the scope of each option and their ability to address the identified network need, assuming all solution components are implemented in full.

Table 5-1: Options to address the identified need and their solution descriptions

Option	High Level Description	Ability to address identified network need
Option 1 Do Nothing	This is the base case, assuming no additional expenditure in the NDS supply area.	Nil.
Option 2 North Heidelberg Plan	This is the option that addresses the most severe limitations in the network particularly those in the eastern side of the NDS supply area being the northern Heidelberg area.	Addresses the northern Heidelberg area sub-transmission limitations. Addresses all distribution feeder limitations.
Option 3 North Heidelberg and Coburg Plan	This is the option that addresses the network limitations in all parts of the NDS supply area including the northern Heidelberg area in the east and the Coburg area in the west.	Addresses the northern Heidelberg area and Coburg area sub-transmission limitations. Addresses the Coburg South zone substation limitation. Addresses all distribution feeder limitations.
Option 4 BESS Plan	40 MW / 950 MWh BESS ramp up over 10 years, distributed across CS 05, NH & WT 22 kV feeders.	Addresses the northern Heidelberg area sub-transmission limitations. Addresses all distribution feeder limitations.
Option 5 DM Plan	40 MW / 950 MWh DM ramp up over 10 years, distributed across CS 05, NH & WT 11 kV feeders.	

Table 5-2 itemises the credible solutions within each of the network development options assessed in this NDS.

Table 5-2: Summary of credible solutions comprising each network option

Asset Limitation	Option 1	Option 2	Option 3

	Do Nothing	North Heidelberg Plan	North Heidelberg and Coburg Plan
NEI-NH-NEL-WT	Nil.	Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop	Augment TTS-NEI-NH-NEL-WT-TTS
CN-CS		Nil.	Augment TTS-CN-CS-TTS
CS		Nil.	Augment CS
CS 05		Augment feeder CS0-005	
CN 06		Load transfers from CN 06 to CN 04 and CN 10	
NH 02		Augment section of NH0-002	
TT 10		Augment feeder TT0-011	

5.2 Options Project and On-going Operational Costs

Table 5-4 summarises the credible network solution capital costs and scope of work, and the identified optimum economic timing of each solution based on the EUE risk of the associated network limitation.

Table 5-3: Summary of Credible Network Solution Capital and Annualised Costs (Real 2024)

Credible Network Solutions	Scope of Work Section	Option	Capital Cost ($M)	Annual Cost ($k pa)[14]	Network Limitation	Optimum Timing[15]
Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop	8.1	2	[redacted]	[redacted]	TTS-NEI-NH-NEL-WT-TTS	2027
Augment TTS-NEI-NH-NEL-WT-TTS	8.2	3	[redacted]	[redacted]	TTS-NEI-NH-NEL-WT-TTS	2027
Augment TTS-CN-CS-TTS	8.3	3	[redacted]	[redacted]	TTS-CN-CS-TTS	Beyond 2035
Augment CS	8.4	3	[redacted]	[redacted]	CS	Beyond 2035
Augment feeder CS0-005	8.5.1	2,3	[redacted]	[redacted]	CS 05	2030
Load transfers from CN 06 to CN 04 and CN 10	-	2,3	[redacted]	[redacted]	CN 06	2031
Augment section of NH0-002	8.5.2	2,3	[redacted]	[redacted]	NH 02	2031
Augment feeder TT0-011	8.5.3	2,3	[redacted]	[redacted]	TT 10	2028

Based on an aggregation of the cost of the various solutions above that make up each option, and their optimum timing based on a comparison of their annualised costs with the do-nothing value of EUE, the costs for each option are summarised in Table 5-4 below. The incremental annual O&M expenditure is estimated at 1% of the capital costs within each option. Present values are calculated over an economic analysis period of 20 years.

[14] Based on regulated discount rate.

[15] Year in which the value of EUE exceeds the annualised cost of the solution.

Table 5-4: Summary of Option Capital Costs ($M Real 2024)

Capital Cost	Option 1	Option 2	Option 3
Option total capital cost	**0.0**	**15.2**	**30.1**
PV of total capital cost	0.0	14.1	28.3
PV of O&M cost	0.0	2.1	4.3
PV of option total capital and O&M cost	**0.0**	**16.2**	**32.6**

5.3 Options Ability to Address the Need

This section presents the maximum demand forecast and asset utilisations over the next 10-years for the supply area, taking into account the impact of each option and its ability to address the forecast overloads on the network as was tabulated in Table 2-6, Table 2-7, Table 2-8 and Table 2-9.

This assessment supports us in determining the option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM, and which is therefore consistent with the long-term interests of our customers.

The "do nothing" option presents the forecast EUE for the NDS supply area, assuming none of the identified network development options are implemented. It is used as a base case against which all of the credible network development options are compared and shows the comparative benefits of each credible option.

The risks associated with the "do nothing" option are:

- Inability to connect new customer load.
- 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 operated above limits.
- Inability to restore all lost supplies in the event of loss of a critical asset during peak demand period.
- Deterioration of supply reliability due to capacity shortfall; and
- Intangible costs to Jemena arising from negative publicity due to longer supply restoration time during and following hot weather events.

Table 5-5 presents the new ratings of the credible solutions applied for each option. Asset not listed in this table have no change to their ratings, therefore the Option 1 ratings presented in section 2.1.1 apply to those assets.

Table 5-5: Ratings Before and After Solutions Applied (MVA)[16]

Asset	Option	Summer Before	Summer After	Winter Before	Winter After	Solution Applied
TTS-NEI-NH-NEL-WT-TTS	3	117.2	195.0	126.3	210.0	8.2
TTS-NEI-NH-NEL-WT-EPN-PTN-TTS	2		277.3		327.0	8.1
CN-CS	3	117.2	187.0	126.3	202.0	8.3
CS	3	42.2	84.4	47.3	95.6	8.4
CS 05	2, 3	12.4	14.3	12.4	14.3	8.5.1
NH 08[17]	2, 3	8.2	14.3	8.2	14.3	8.5.2
TT 11[18]	2, 3	12.4	14.3	12.4	14.3	8.5.3

[16] (N-1) ratings for sub-transmission and zone substations. (N) rating for 22 kV feeders.

[17] To offload NH 02.

[18] To offload TT 10.

5.4 Options Reliability Assessment

The following tables detail the annualised EUE for each option, assuming all solutions are in service based on their optimal timing as identified in Table 5-3.

5.4.1 Option 2 – North Heidelberg Plan

Table 5-6 details the zone substation and sub-transmission EUE for Option 2 over the planning horizon.

Table 5-6: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 2

Asset	CS	TTS-CN-CS-TTS	TTS-NEI-NH-NEL-WT-TTS	Total
2025	0.1	0.0	0.1	**0.2**
2026	0.3	0.0	0.3	**0.6**
2027	0.5	0.0	0.0	**0.5**
2028	0.6	0.0	0.0	**0.6**
2029	0.7	0.0	0.0	**0.7**
2030	0.9	0.0	0.0	**1.0**
2031	1.2	0.0	0.0	**1.3**
2032	1.7	0.0	0.0	**1.7**
2033	2.3	0.0	0.0	**2.3**
2034	3.5	0.1	0.0	**3.5**

Table 5-7 details the distribution feeder EUE for Option 2 over the planning horizon.

Table 5-7: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 2

Asset	CS 05	NH 02	TT 10	Total
2025	0.0	0.0	0.0	**0.0**
2026	5.3	0.1	1.2	**6.6**
2027	9.6	0.4	6.1	**16.1**
2028	13.2	0.6	0.0	**13.8**
2029	14.9	0.9	0.0	**15.8**
2030	0.0	1.8	0.0	**1.8**
2031	0.0	0.0	0.0	**0.0**
2032	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	**0.0**

5.4.2 Option 3 – North Heidelberg and Coburg Plan

Table 5-8 details the zone substation and sub-transmission EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-8: Zone Substation and Sub-transmission Expected Unserved Energy (MWh pa) – Option 3

Asset	CS	TTS-CN-CS-TTS	TTS-NEI-NH-NEL-WT-TTS	Total
2025	0.1	0.0	0.1	**0.2**
2026	0.3	0.0	0.3	**0.6**
2027	0.5	0.0	0.0	**0.5**
2028	0.6	0.0	0.0	**0.6**
2029	0.7	0.0	0.0	**0.7**
2030	0.9	0.0	0.0	**1.0**
2031	1.2	0.0	0.0	**1.3**
2032	1.7	0.0	0.0	**1.7**
2033	2.3	0.0	0.0	**2.3**
2034	3.5	0.1	0.0	**3.5**

Table 5-9 details the distribution feeder EUE for Option 3 over the planning horizon for the identified network limitations.

Table 5-9: Distribution Feeder Expected Unserved Energy (MWh pa) – Option 3

Asset	CS 05	NH 02	TT 10	Total
2025	0.0	0.0	0.0	**0.0**
2026	5.3	0.1	1.2	**6.6**
2027	9.6	0.4	6.1	**16.1**
2028	13.2	0.6	0.0	**13.8**
2029	14.9	0.9	0.0	**15.8**
2030	0.0	1.8	0.0	**1.8**
2031	0.0	0.0	0.0	**0.0**
2032	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	**0.0**

6. Economic Evaluation

This section presents the results of an economic cost-benefit analysis undertaken on each option. It takes into account the present value of capital and additional operating costs, and the present value of the EUE over an analysis period of 20-years. Capital costs over the 10-year planning horizon are included which address all of the identified network needs over the same period.

6.1 Cost-Benefit Analysis

A summary of the cost-benefit analysis assessed for each option is present in Table 6-1. Option 2 maximises the NPV, relative to all other options assessed.

Table 6-1: Summary of NPV Cost-Benefit Analysis ($M Real 2024)

Option	Total Capital Cost	Present Value of Capital and O&M Cost	Present Value of Reliability Benefit	Net Present Value (NPV)	Ranking
Option 1 - Do Nothing	0.0	0.0	0.0	0.0	5
Option 2 – North Heidelberg Plan	**15.2**	**16.2**	**911**	**895**	**1**
Option 3 - North Heidelberg and Coburg Plan	30.0	32.5	913	880	2
Option 4 – BESS Plan	0	475	911	436	4
Option 5 – DM Plan	0	194	911	717	3

6.2 Sensitivity Analysis

A sensitivity analysis has been undertaken to test the robustness of the preferred network development option to credible pessimistic changes in key input assumptions. These changes are applied individually to each option as follows:

- Reducing VCR by 10%, thereby reducing customer benefits by 10%.
- Increasing VCR by 10%, thereby increasing customer benefits by 10%.
- Raising the discount rate by 1%, thereby reducing the attractiveness of capex investments.
- Lowering the discount rate by 1%, thereby improving the attractiveness of capex investments.
- Incurring 30% higher capital costs across all projects with an associated rise in the O&M.
- Achieving 30% lower capital costs across all projects with an associated reduction in the O&M; and

- No EV charging during peak electricity demand periods.

Table 6-2 below presents the results for the sensitivity analysis.

Table 6-2: Sensitivity of NPV to Changes in Input Assumptions ($M Real 2024)

Option	Baseline	VCR 10% Lower	VCR 10% Higher	Discount Rate 1% Higher	Discount Rate 1% Lower	Capital Costs 30% Higher	Capital Costs 30% Lower	No EV Charging at Peak Demand
Option 1 - Do Nothing	0	0	0	0	0	0	0	0
Option 2 – North Heidelberg Plan	**895**	**804**	**986**	**780**	**870**	**890**	**900**	**838**
Option 3 – North Heidelberg Plan and Coburg Plan	880	789	972	765	854	870	890	823

Option 2 remains the preferred network development option, retaining the highest positive NPV for all credible sensitivities.

Table 6-3 lists the project deferrals that would be triggered if all EV charging avoided peak electricity demand periods.

Table 6-3: Deferrals for Option 2 with no EV Charging at Peak Electricity Demand

Projects	Revised Timing	Years Deferred
Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop	2027	0
Augment feeder TT0-011	2028	0
Augment feeder CS0-005	2030	0
Augment section of NH0-002	2035	4
Load transfers from CN 06 to CN 04 and CN 10	2031	0

Notwithstanding this assessment, our analysis—corroborated against all of AEMO's ISP scenarios—confirms that there are no scenarios in which EV charging has no impact on peak demand.

7. Recommendation and Next Steps

The assessment demonstrates that the preferred network development plan is to implement Option 2 (North Heidelberg Plan) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 2 provides a 20-year present value net market benefit of $895 million, with a present value of $14.1 million of investment (over 10-years). The market benefits forecast to be delivered by the preferred solution are driven by a reduction in the amount of expected unserved energy over the planning period.

7.1 Recommended Development Plan

The preferred network development plan (Option 2) to address the identified network limitations include the following**:**

Table 7-1: Option 2 – North Heidelberg Plan

Timing	Projects	Cost (Real 2024)	Limitation Addressed
2027	Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop	[redacted]	NEI-NH-NEL-WT overload
2028	Augment feeder TT0-011	[redacted]	TT 10 overload
2030	Augment feeder CS0-005	[redacted]	CS 05 overload
2031	Augment section of NH0-002	[redacted]	NH 02 overload
2031	Load transfers from CN 06 to CN 04 and CN 10	[redacted]	CN 06 overload
Total		**$15.2 million**	
Present Value Total		**$14.1 million**	

The estimated total capital cost of Option 2 for JEN over 10-years to address the identified network limitations is $15.2 million ($2024, Real).

8. Appendix A – High Level Scopes of Work

8.1 Augment TTS-NH(NEI)-NEL-WT-TTS 66kV loop

This solution increases the capacity of the 66 kV sub-transmission loops supplying into the northern Heidelberg area to by tying the TTS-NEI-NH-WT-TTS loop with the TTS-PTN-EPN-EP-TTS loop, with two teed lines from NH teed into the EPN-PTN 66 kV line, and from NEI teed into the NEL-NH 66 kV line. The existing and proposed sub-transmission arrangements are shown below.

Existing

[redacted]

Proposed

[redacted]

The two teed lines are formed around EPN and NH as shown below. The existing EPN-PTN line becomes the EPN-NH-PTN line, and the existing TTS-NEI/NH and NEL-NH lines become the TTS-NEI and NEI-NEL-NH 66 kV lines.

[redacted]

The scope includes:

- Cutting into existing NEI-NH line segment at Waiora Road and run approximately 1.5 km of new single circuit 37/3.75AAC (built to 100ºC/75ºC) to tie onto existing NH-NEL line to create new line segment NEI-NEL-NH.
- Create a new 66 kV tie point on the existing EPN-PTN line and run approximately 3.3 km of new single circuit 37/3.75 AAC (built to 100ºC/75ºC) to connect to existing 66 kV line east of [redacted]. This will create new line EPN-NH-PTN.
- Swap TTS-PTN and TTS-CS 66 kV lines at TTS to remove double circuit line risk of TTS-PTN and TTS-NEI circuits sharing the same pole line. Redirect TTS-PTN line [redacted] by running approximately 0.4 km of new 37/3.75AAC (built to 100ºC/75ºC). Tie into the existing 66 kV line terminating into PTN. Run approximately 0.2 km of new 37/3.75AAC (built to 100ºC/75ºC) to tie onto existing 66 kV line to provide continuity to TTS-CS line.
- Reconductor 2.0 km of line on NEL-NH/NEI with new 37/3.75AAC overhead line (built to 100ºC/75ºC).
- Check 66 kV dropper at EPN (along PTN-EPN/NH segment) achieves a minimum rating of 1025A. Upgrade dropper if this requirement is not met.
- A new 66 kV line CB is required at NEI for the NEI-NEL-NH 66 kV line. NEI will need to be converted from a tee-off substation to a fully switched substation. A new 0.2 km return circuit of 37/3.75AAC overhead line (built to 100ºC/75ºC) from the new NEI 66 kV line CB to the corner of [redacted] may run above or on the same pole line as the other circuit if there is insufficient room to segregate.
- New 3-way protection schemes are required on each teed line at NEI, NEL, EPN, PTN and NH.

8.2 Augment TTS-NEI-NH-NEL-WT-TTS

This option involves installing a third 66 kV line into the loop with a new line connecting TTS teed into the existing NEL-WT 66 kV line.

[redacted]

The scope includes:

- install 0.6 km of 3x 1/c 1200 mm^2 Cu 66 kV underground exit cables at TTS to Keon Parade along railway station carpark access road to achieve a rating of at least 1425A.
- install (by rebuilding existing HV lines) a 13 km new 66 kV line using 37/3.75AAC 100/75^{o}C conductor, from the end of the TTS exit cable in Keon Parade teed into the NEL-WT 66 kV line just north of NEL zone substation to achieve a rating of at least 1,025A.

8.3 Augment TTS-CN-CS-TTS

This option involves installing a third 66 kV line into the loop with a new line connecting TTS teed into the existing CN-CS 66 kV line.

[redacted]

The scope includes:

- install 0.6 km of 3x 1/c 1200 mm^2 Cu 66 kV underground exit cables at TTS to Keon Parade along railway station carpark access road to achieve a rating of at least 1,125A.
- install (by rebuilding existing HV lines) a 7 km new 66 kV line using 37/3.75AAC 100/75°C conductor, from the end of the TTS exit cable in Keon Parade teed into the CN-CS 66 kV line just south of or at CN zone substation to achieve a rating of at least 1,025A.

8.4 Augment CS

This option involves installing a 3rd 66/22 kV 20/33 MVA transformer, 3rd 22 kV bus and an additional 66kV bus tie CB at CS.

[redacted]

8.5 22 kV Feeders

8.5.1 Augment feeder CS0-005

CS 05 is the feeder that supplies the southwest region of the NDS supply area, an area which is experiencing growth in high-density residential developments in Coburg and Pasco Vale South. The existing network arrangement is shown below.

[redacted]

To upgrade the rating of CS 05 involves replacing 0.06 km of HV underground cable with 300mm 3/c AL HV and reconductoring 0.6 km of existing HV overhead conductor with 19/3.25 AAC as shown below.

[redacted]

The rating of CS 05 will increase to 375 A.

8.5.2 Augment section of NH0-002

NH 02 is the feeder that supplies the east region of the NDS supply area, an area which is experiencing growth in high-density residential developments in Macleod. The existing network arrangement is shown below.

[redacted]

To upgrade the rating of NH 08 involves replacing 0.45 km of HV underground cable with 300 mm^2 3/c AL HV and reconductoring 0.4 km of existing HV overhead conductor with 19/3.25 AAC as shown below.

[redacted]

The rating of NH 08 will increase to 375 A allowing transfer from NH 02.

8.5.3 Augment feeder TT0-011

This solution involves upgrading a section of TT 11 overhead to increase the rating of the feeder to 375 A. Which can be used to offload the adjacent TT feeders via existing tie points on the network.

[redacted]

To upgrade the rating of TT 11 involves replacing 0.10km of HV underground cable with 300mm^2 3/c AL HV, thermally uprating .75 km of existing HV conductor and reconductoring 2.3 km of existing HV overhead conductor with 19/3.25 AAC as shown above.