Jemena Electricity Networks (Vic) Ltd

Regulatory Investment Test for Distribution (RIT-D) Draft Project Assessment Report

Keilor - Tullamarine - Airport West - Pascoe Vale
66 kV sub-transmission loop capacity constraint

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Regulatory Investment Test for Distribution (RIT-D) Draft Project Assessment Report

Authorisation

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History

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EXECUTIVE SUMMARY

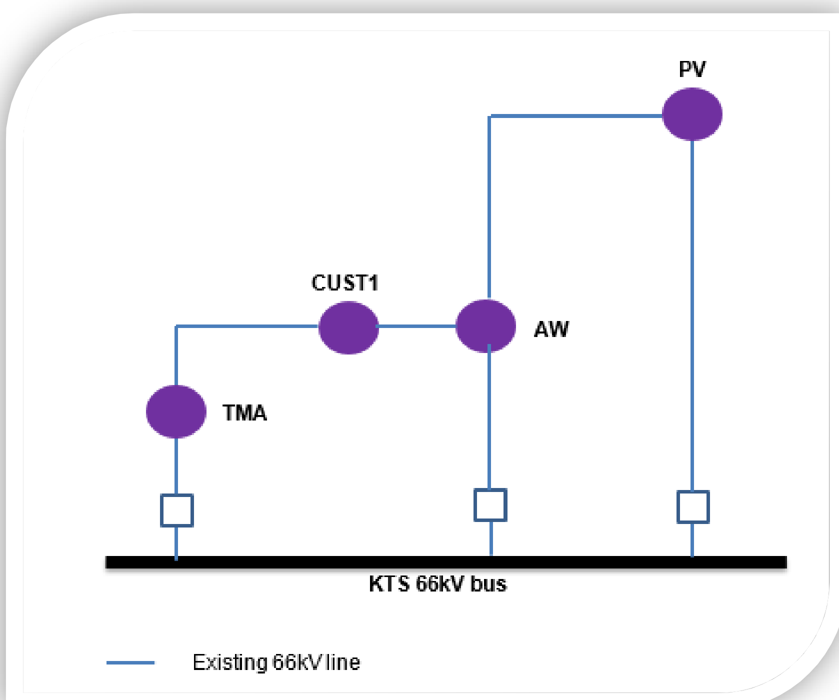
Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie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

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

Identified need

Jemena Electricity Network (JEN) zone substations at Tullamarine (**TMA**), Airport West (**AW**), Pascoe Vale (**PV**), are supplied from the Transmission Network at Keilor Terminal Station (**KTS**) via a 66 kV sub-transmission loop (**KTS sub-transmission loop**). This loop also supplies a major customer zone substation (CUST1). The configuration of the KTS sub-transmission loop is shown in Figure ES–1.

Figure ES–1: Simplified single line diagram showing the KTS sub-transmission loop



The KTS sub-transmission loop is already fully utilised i.e. it can supply up to 165 MVA continuously, but is loaded up to 190 MVA with the understanding that if either the KTS-TMA or the KTS-AW line fails then customer load will need to shed (i.e. turned off) to reduce the load below 165 MVA. If the loop is loaded above 190 MVA and either the KTS-TMA or KTS-AW line fails, there is not enough time to reduce the load below 165 MVA before the remaining line becomes overloaded, the conductor between the poles sags, and breaches electric line clearance safety obligations which poses safety risk to the public.

As reported in the 2016 Distribution Annual Planning Report (DAPR)[1], JEN has forecast an 8 MVA increase for the combined AW, PV and TMA loads under 50% Probability of Exceedance (POE) conditions by 2021. Furthermore, since publishing the 2016 DAPR, JEN has had two major customers (referred to in this report as CUST1 and CUST2) seek an increase in their contracted demand by 12 MVA and 16 MVA respectively. Based on these figures, an additional 36 MVA of capacity will be required to accommodate the forecast load growth on this KTS sub-transmission loop by 2021.

Screening for Non-network Options

Jemena has undertaken a screening assessment of non-network options to address the identified network constraint. Non-network options considered were demand response (including behind the meter embedded generation), mobile generation and battery storage. Jemena has determined that non-network options do not provide a feasible solution to the constraint nor do non-network options provide cost effective opportunities to defer the proposed network augmentation. Based on this determination, a non-network options report has not been published for this RIT-D.

Network Options Considered

The following options have been considered to address the capacity issue on the KTS loop:

- Base Case: Do Nothing;
- Option 1: Re-conductor the KTS-TMA-AW-KTS 66 kV loop with higher capacity conductor;
- Option 2: Install a new KTS-CUST1 66 kV line to form a four legged 66 kV loop;
- Option 3: Split the existing 66 kV loop by installing a new KTS-CUST1 66 kV line; and
- Option 4: Split the existing 66 kV loop by installing new KTS-CUST1 and KTS-AW No. 2 66 kV lines.

Proposed preferred option

The options analysis identifies that Option 4 - split the existing 66 kV loop by installing new KTS-CUST1 and KTS-AW 66 kV lines is the preferred network augmentation option as it is shown to:

- Have the highest net present value for JEN customers of all options under all demand growth scenarios considered; and
- Achieve the capital expenditure objective(s) as per the National Electricity Rules (NER) Section 6.5.7, by increasing the sub-transmission loop capacity to meet expected demand and maintain the quality, reliability and security of supply for standard control service in the supply area.

[1] http://jemena.com.au/getattachment/industry/electricity/Network-planning/2016-Distribution-Annual-Planning-Report.pdf.aspx

Table ES–1 shows the total project cost breakdown for Option 4 delivered by November 2019. Applying the discount rate of 6.37% per year, this preferred solution has a net economic benefit of $255 million (Real $2017) over the fifteen year assessment period under a moderate demand growth scenario.

Table ES–1: Proposed preferred solution cost estimate breakdown

	NPV project cost ($M Real 2017)
Network augmentation capital cost (2019)	10.96
Network augmentation operational cost (2020-2032)	0.20
Total project expenditure (2019-2032)	11.16

Submission and next steps

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

All submissions and enquiries should be directed to:

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Email: PlanningRequest@jemena.com.au
Phone: (03) 9173 8279

Submissions should be lodged with us on or before 21 August 2017.

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

Following our consideration of any submissions on this Draft Project Assessment Report (DPAR), we will proceed to prepare a Final Project Assessment Report (FPAR). That report will include a summary of, and commentary on, any submissions to this report, and present the final preferred solution to address the Sunbury Zone Substation thermal capacity and reliability constraints. Publishing the FPAR will the final stage in the RIT-D process.

We intend to publish the FPAR by 4 September 2017. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2017 Distribution Annual Planning Report.

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GLOSSARY

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Constraint	Refers to a constraint on network power transfers that affects customer service.
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 close to 333,000 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.
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($5m), in the National Electricity Market (NEM).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
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
AW	Airport West Zone Substation
CUST1	Customer 1
CUST2	Customer 2
JEN	Jemena Electricity Network
KTS	Keilor Terminal Station
MD	Maximum Demand
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
POE	Probability of Exceedance
PV	Pascoe Vale Zone Substation
RIT-D	Regulatory Investment Test for Distribution
TMA	Tullamarine Zone Substation
VCR	Value of Customer Reliability

1. INTRODUCTION

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

1.1 RIT-D PURPOSE AND PROCESS

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

The RIT-D applies in circumstances where a network problem (an "identified need") exists and the estimated augmentation component capital cost of the most expensive potential credible option to address the identified need is more than $5 million. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need.

Under the RIT-D consultation procedures, distribution businesses are required to prepare and publish a non-network options report unless it is determined on reasonable grounds that there are no potential credible non-network options to address the identified need. In the case of this RIT-D, Jemena has determined that there are no credible non-network options which address the identified constraint on the KTS sub-transmission loop which supplies Tullamarine (TMA), Airport West (AW) and Pascoe Vale zone substations as well as a major customer zone substation (CUST1).

This document is Jemena's draft project assessment report for the KTS sub-transmission loop. In accordance with the requirements of the National Electricity Rules (NER) clause 5.17.4 this report describes:

- the identified need in relation to the KTS sub-transmission loop;
- methodology and assumptions used to determine that there are no credible non-network options which address the identified need;
- the credible network options assessed that may address the identified need;
- the methodologies used to quantify market benefits;
- the net present value assessment results for the potential credible options assessed; and
- the technical characteristics of the proposed preferred credible option.

1.2 OBJECTIVE

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

2. BACKGROUND

This section provides an overview of the supply area, describes the general arrangement of the KTS sub-transmission loop which supplies Tullamarine (TMA), Airport West (AW) and Pascoe Vale (PV) zone substations as well as a major customer (CUST1) zone substation. It also gives a brief overview of existing network limitations.

2.1 NETWORK SUPPLY ARRANGEMENTS

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena Electricity Networks (JEN) service area covers 950 square kilometres of northwest greater Melbourne and includes some major transport routes and the Melbourne International Airport, which is located at the approximate physical centre of the network. The network comprises over 6,000[2] kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to around 333,000 homes and businesses for a number of energy retailers. The network service area spans from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

JEN zone substations at Tullamarine (TMA), Airport West (AW), Pascoe Vale (PV), as well as a major customer zone substation (CUST1) are supplied from the Transmission Network at Keilor Terminal Station (KTS) via a 66 kV sub-transmission loop as shown in Figure 2–1. The areas supplied by TMA, AW and PV zone substations are shown in Figure 2–2.

[2] Does not include low voltage services

Figure 2–1: KTS sub-transmission loop simplified single line diagram

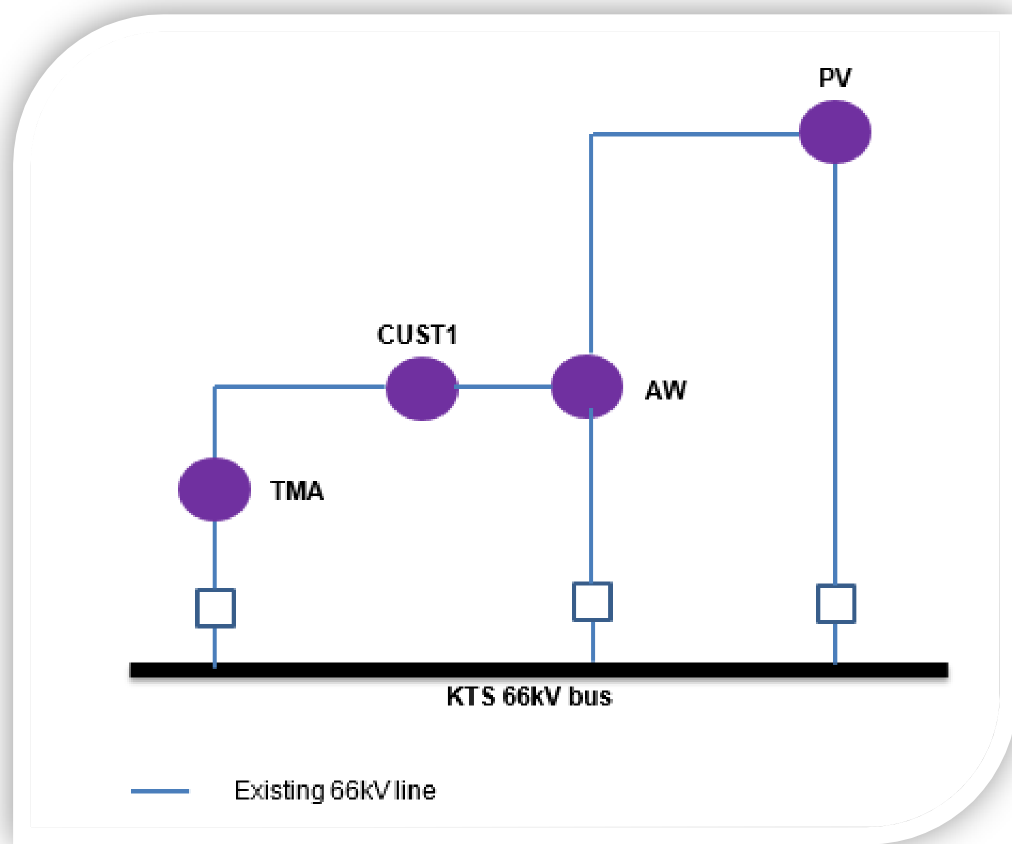
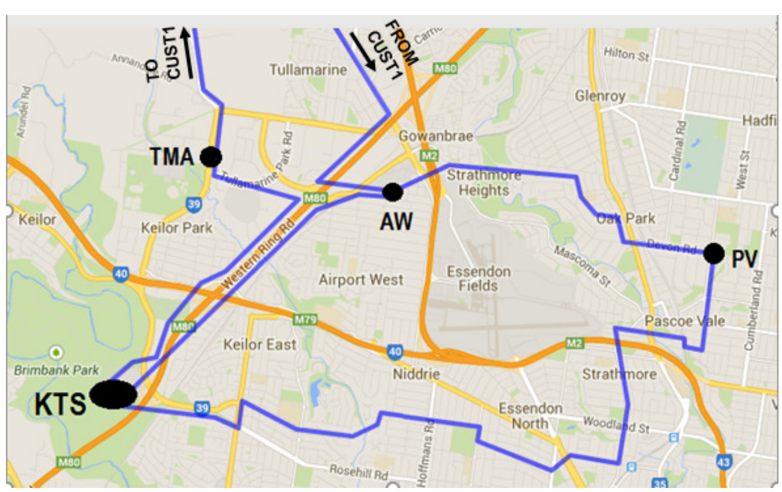


Figure 2–2: KTS sub-transmission loop supply area



3. IDENTIFIED NEED

The KTS 66 kV sub-transmission loop that supplies Tullamarine (TMA), Airport West (AW) and Pascoe Vale (PV) zone substations has a continuous rated capacity of approximately 165 MVA. This is the maximum load that can be supplied from KTS to ensure the N-1 post contingent loading on each of the remaining in-service 66 kV lines does not exceed their continuous rating. In practice, Jemena operates this loop up to 190 MVA to ensure the N-1 post contingent loading does not exceed 120% of the rated line capacities. This gives operators adequate time to manually reduce load (by transferring or turning off) if either the KTS-TMA or KTS-AW lines fail, so that the remaining in-service lines are operating within their continuous rating. If the loop is loaded above 190 MVA and either the KTS-TMA or KTS-AW line fails, there is not enough time to reduce the load below 165 MVA before the line becomes overloaded, causing the conductors between poles to sag and potentially breache electric line clearance safety obligations, which is a risk to public safety.

As reported in the 2016 Distribution Annual Planning Report (DAPR)[3], JEN has forecast an 8 MVA increase for the combined AW, PV and TMA loads under 50% Probability of Exceedance (POE) conditions by 2021. Furthermore, since publishing the 2016 DAPR, JEN has had two major customers (referred to in this report as CUST1 and CUST2) seek an increase in their contracted demand by 12 MVA and 16 MVA respectively. Based on these figures, an additional 36 MVA of capacity will be required to accommodate the forecast load growth on this KTS sub-transmission loop by 2021.

3.1 DEMAND FORECASTS

In the assessment of market benefits, the following demand growth scenarios have been considered:

- Planning demand growth – demand on the KTS sub-transmission loop assumed to be as forecast in the 2016 DAPR;
- Moderate demand growth – demand at TMA, AW and PV assumed to be as forecast in the 2016 DAPR. In addition, the two major customers, CUST1 and CUST2, are assumed to reach their forecast demand increases of 12 MVA and 16 MVA by 2026; and
- Fast demand growth – demand at TMA, AW and PV assumed to be as forecast in the 2016 DAPR. In addition, the two major customers, CUST1 and CUST2, are assumed to reach their forecast demand increases of 12 MVA and 16 MVA by 2021;

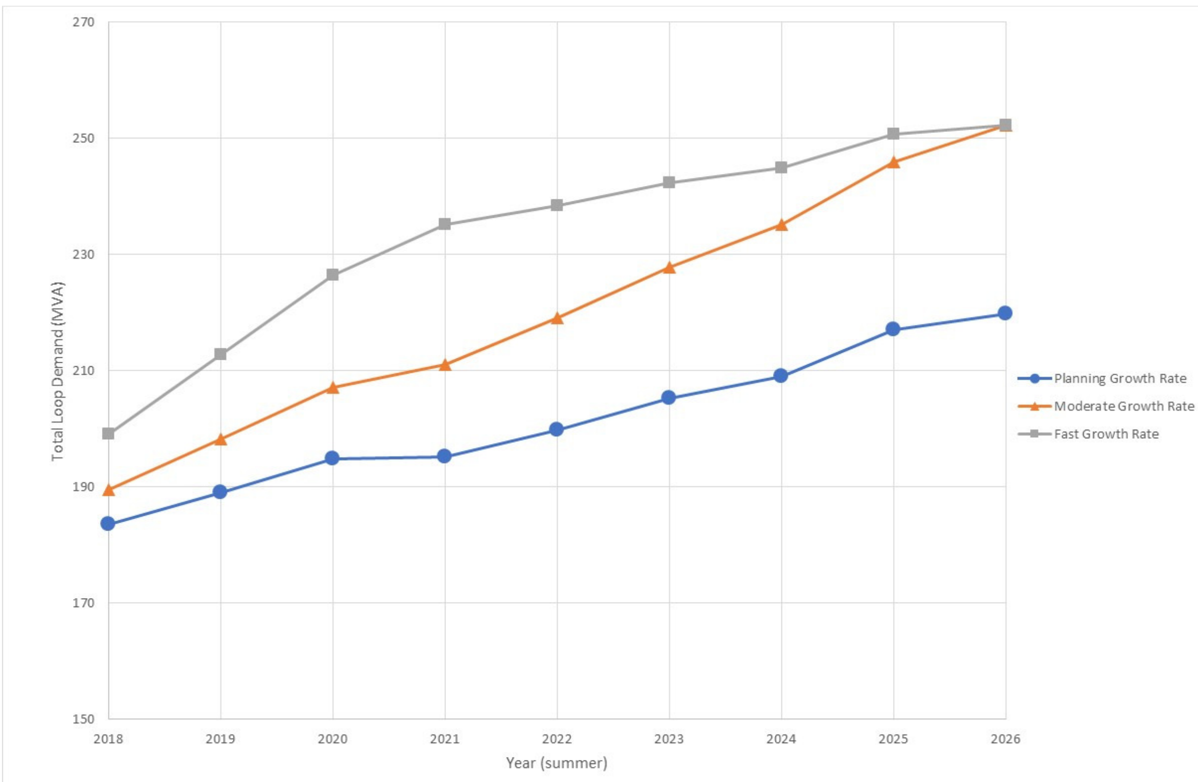
The forecast demands for these three scenarios are summarised in Table 3–1 and Figure 3–1. The 10% and 50% Probability of Exceedance (POE) demand forecasts for TMA, AW and PV are tabulated in Appendix A. For confidentiality reasons, Jemena is unable to explicitly include the CUST1 and CUST2 demand forecasts. However, these have been included in the summary table and figure below.

3 http://jemena.com.au/getattachment/industry/electricity/Network-planning/2016-Distribution-Annual-Planning-Report.pdf.aspx

Table 3–1: KTS sub-transmission loop demand growth scenario forecasts

Demand Growth Scenario	Total Loop Demand (MVA) 10% POE								
	2018	2019	2020	2021	2022	2023	2024	2025	2026
Planning demand growth	189	194	201	201	206	213	217	226	229
Moderate demand growth	195	205	214	219	228	238	247	259	267
Fast demand growth	206	221	237	247	250	254	257	265	267

Figure 3–1: KTS sub-transmission loop demand growth scenario forecasts



4. ASSUMPTIONS RELATING TO IDENTIFIED NEED

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

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

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

In addition to the demand forecast scenarios described in the previous section, the key assumptions that have been applied in quantifying the KTS sub-transmission loop limitations include network asset ratings and network outage rates as outlined below.

4.1 NETWORK ASSET RATINGS

In planning our network, Jemena applies a summer and winter rating to its temperature sensitive assets, which provides some recognition of the difference in ambient temperature between the two seasons and the heating or cooling effect that the ambient temperature has on an asset's rating.

Table 4–1 below lists the summer and winter ratings which are derived from the maximum allowable current carry capacity of the conductor. As a conductor carries more current, its temperature rises, causing the conductor to sag. The rating is typically set by the minimum allowable clearance between spans.

Table 4–1: KTS sub-transmission loop line ratings

	Summer Rating (MVA)	Short term summer rating (MVA)	Winter Rating (MVA)	Short term winter rating (MVA)
KTS – TMA	101.7	122.0	105.7	126.8
KTS – AW	117.2	140.6	128.0	153.6
KTS - PV	101.7	122.0	105.7	126.8
Maximum loop load	261.0	313.0	276.0	332.0

Note that due to relative circuit impedances, the lines do not share load equally and therefore, the aggregate capacity of the KTS sub-transmission loop (i.e. maximum loop load in Table 4–1) is less than the summated capacity of each of the individual circuits.

The short term seasonal rating is 120% of the normal continuous seasonal rating. As described further in Section 8.1, when calculating the energy at risk, it is assumed that the loading on any circuit can never exceed that short term seasonal rating, and demand must be shed to ensure that in the event of a contingency, the resulting loading on all remaining in-service circuits, does not exceed the short term seasonal rating.

In practise, load shedding prior to an outage would be a last resort for Jemena operations staff. However, this must be balanced against the risk of damage to the remaining in service asset if an outage were to occur, resulting in a flow significantly above the line rating.

4.2 NETWORK OUTAGE RATES

In using a probabilistic economic planning methodology, the network outage rates applied in assessing the costs of the limitation and benefits of augmentation can have a large impact on the optimal augmentation timing.

In assessing the cost of expected unserved energy due to the identified KTS sub-transmission loop limitations, Jemena has considered the potential failure of the KTS-TMA, KTS-AW and KTS-PV sub-transmission lines. Based on historical outage data, an outage frequency of 0.1 outages per kilometre of line length per annum has been assumed. The average time to repair a 66 kV line outage is assumed to be 4 hours.

Table 4–2 shows the network outage rates applied in calculating the expected unserved energy for the options analysis included in this report.

Table 4–2: KTS sub-transmission loop outage rates

Sub-transmission line	Line length (km)	Outage probability (%)
KTS – TMA	7.0	0.03
KTS - AW	5.1	0.02
KTS - PV	11.1	0.05

5. SCREENING FOR NON-NETWORK OPTIONS

5.1 METHODOLOGY

Jemena has developed a high level screening methodology to identify opportunities to prudently defer network augmentation works through demand management. This screening process was reviewed and supported by an independent consultant as part of the Jemena's revised 2016-2020 Electricity Distribution Price Review (EDPR) submission[4].

This methodology has been applied to the network constraint considered in this RIT-D as follows:

1. Identify the preferred network augmentation project – as detailed in Section 8.2 of this report the preferred network solution to the identified network constraint is to split the existing 66 kV loop by installing new KTS-CUST1 and KTS-AW 66 kV lines (KTS-AW No.2). The total cost for this solution is estimated at $11.2 M (real $2017)
2. Calculate benefit of deferring network augmentation project, by using the following equation:

$$\text{Deferral Benefit} = \text{Project cost} * \text{discount rate} * \text{number of years of deferral}$$

   The discount rate is assumed to be 6.37% and a single year of deferral is considered. Based on the project cost of $11.2M, the deferral benefit is then $745k.

3. Determine load and energy at risk – as outlined in Section 8.3 the optimal timing for the preferred network solution is November 2019 (i.e. before 2020 summer). The forecast demand for 2020 was used to determine the load and energy the demand management options would need to deliver, to defer the project by one year. Under the moderate growth demand scenario, the maximum load at risk in 2020 is forecast to be 45.6 MVA and the weighted expected unserved energy is 29 MWh (refer Section 8.1.1 for details).
4. Estimate DM option costs – demand response, diesel generation and battery storage options have been considered. The cost basis for each options is outlined in the following section.
5. Review of practical implementation - if based on the DM option costs, any of the options are identified as having potential to defer the network augmentation (i.e. cost of DM option is within a margin of two times the value of project deferral) the practical implementation is reviewed for potential limitations (e.g. insufficient C&I customer base to achieve required demand response).

5.2 COST BASIS

The cost basis used to estimate the costs for the demand management (DM) options is outlined in the following sections.

[4] Advisian "Demand Management Options An Independent Report for Jemena Electricity Networks" http://jemena.com.au/documents/price-reviews/electricity/detailed-submission-2016-plan/attachment-07-16-advisian-demand-management-option.aspx.

5.2.1 DEMAND RESPONSE

Demand Response (DR) is any action to reduce electrical load taken by an electricity end user in response to an instruction or price signal. End users can include industrial, commercial or domestic facilities, and actions can be at a fixed time of day, triggered by a message or automated, with pre-dispatch notification (e.g. day-ahead) or immediate.

Table 5–1 shows the cost basis that has been used to estimate the costs of DR in Jemena's network area. These costs are based on those used in the Demand Management Options Report which formed part of the 2016-2020 EDPR submission[5]. It is assumed that the DR will be provided by large commercial and industrial customers with an 80% capacity factor (i.e. at any given time 80% of the contracted DR load would be available). It is also assumed that the DR includes embedded generation in the form of emergency back-up generators on the customers sites, although there is likely to be additional costs associated with recruitment of these embedded generators including fuel costs and costs to modify the plant so that it can connect to the Jemena network.

Table 5–1: Cost basis for demand response programs

	Unit	Value
Load available per customer	MVA	0.5
Capacity factor, delivered load vs contracted load	%	80%
Cost per customer for hardware	$	$20,000
Cost per year for programme setup	$/year	$5,000
Payments to customers for capacity	$/MVA	$20,000
Management cost for capacity	$/MVA	$10,000
Payments to customers for delivery	$/MWh	$5,000

5.2.2 ENERGY STORAGE (BATTERIES)

Battery storage systems can be used to store energy at low demand and then discharged at periods of peak demand to alleviate network constraints. Battery storage systems can be operated throughout the year, gaining additional benefit from arbitrage of peak and off peak electricity prices. Batteries are selected based on the peak demand in MVA required (capacity) and the maximum energy to be provided in a single event (size) in MWh. The capacity determines the output of inverters required for discharge of the batteries, while the size determines the number of battery cells.

The cost basis used to estimate the cost of battery storage systems is summarised in Table 5–2. The capital cost of the battery storage is a combination of the inverter, battery cells, storage container and other ancillary (such as battery management system) costs. For the purposes of screening for DM opportunities, an event duration of 2 hours at the equivalent of the peak demand load at risk was assumed to size the required battery storage. In this model, the battery storage is owned and operated by Jemena so the difference between off peak and peak electricity is a benefit. The assumption is that the energy storage facility is operated throughout the year, gaining additional benefit from arbitrage of peak and off peak electricity prices.

[5] Jemena Electricity Networks "Demand Management for Deferral of Network Augmentations – Options Analysis (ELE-PL-0055)" 9 December 2015.

Table 5–2: Cost basis for battery storage

	Unit	Value
Duration of maximum peak equivalent	Hours	2
Installed cost of batteries	$/kWh	$400
Installed cost of inverters	$/kVA	$150
Number of 20ft containers required for batteries	Containers/MWh	2
Cost of 20ft containers	$/container	$20,000
Fixed operating costs as a percentage of installed capital cost	%	3
Cost of off peak electricity for charging	$/MWh	$26
Value of peak electricity when discharging	$/MWh	$56

5.2.3 MOBILE GENERATION (DIESEL)

Mobile generation involves electricity generators brought in by the electricity distribution company to support the network by supplying electricity directly to the network during peak times. Mobile generators are usually diesel packaged into a shipping container size unit for ease of transportation. Gas turbines are also used but are generally more expensive and more difficult to transport. Generator engines are available in size ranges from a few hundred kilowatts (kW) to more than 10 MW. Multiple engines can be combined to form larger capacities and provide redundancy for greater reliability.

The cost basis used to estimate the cost of mobile generation is summarised in Table 5–3. Diesel generation capacity is selected based on the load required in MVA. The mobile generation fixed costs are calculated over five years on the basis of purchasing and installing new units and recovering the residual value of the units at the end of that period. An annualised Net Present Value (NPV) is calculated and fuel costs are estimated based on MWh delivered. The assumption has been made that the generators will be owned and operated by a party that will receive benefit from the MWh of energy produced that will offset some of the fuel cost.

Table 5–3: Cost basis for mobile generation (diesel)

	Unit	Value
Project life	Years	5
Reliability Factor	%	100%
Annual Depreciation	%/year	15%
Installation cost as percentage of unit capex	%	40%
Commissioning cost as percentage of unit capex	%	5%
Opex cost as percentage of unit capex	%/year	3%
Diesel fuel cost	$/litre	$1
Fuel consumption	L/MWh	158
Value of peak electricity	$/MWh	$56

5.3 FINANCIAL EVALUATION

Table 5–4 summarises the results of the non-network options screening undertaken for this RIT-D. It can be seen that the cost of implementing any of the non-network options considered for a single year is more than two times the value of deferring the preferred network solution (i.e. $745k real $2017). Indeed the cost of both the mobile generation and battery storage options is comparable to the total capital cost of the preferred network solution (i.e. $11.2M real $2017) whilst delivering significantly less capacity.

While demand response is a lower cost alternative, a large portion of the cost (~90%) is associated with capacity payments which are incurred annually regardless of whether the demand response is called upon. Furthermore, an analysis of C&I customers supplied from the KTS sub-transmission loop indicates that there are less than 30 customers whose demand exceeds 500 kVA. Therefore large numbers of smaller customers would be required to achieve the required demand response which is unlikely to be cost effective.

While demand response is unlikely to prudently defer network augmentation in this case, Jemena will continue to monitor load growth and work with the large customers on this loop to identify opportunities to manage the network risk ahead of the proposed network augmentation.

Table 5–4: Non-network options screening results

Non-network Option	Non-network option cost for 1 year of deferral ($M)
Demand Response	2.0
Mobile generation	9.5
Battery Storage	13.2

6. NETWORK OPTIONS CONSIDERED IN THE RIT-D

6.1 "DO NOTHING" OPTION (BASE CASE)

The assessment of credible options is based on a cost-benefit analysis that considers the future expected unserved energy of each credible option compared with the base case, where no augmentation option is implemented.

Under this base case, the action required to ensure that loading levels remain within asset capabilities is involuntary load shedding of Jemena's customers. The cost of involuntary load shedding is calculated using the value of customer reliability (VCR) which, for the Jemena electricity network, is currently estimated at $39,440/MWh (Real $2017), as described in Section 7.3.1.1.

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

Since there is no augmentation associated with the base case (Do Nothing) option, this is a zero cost option.

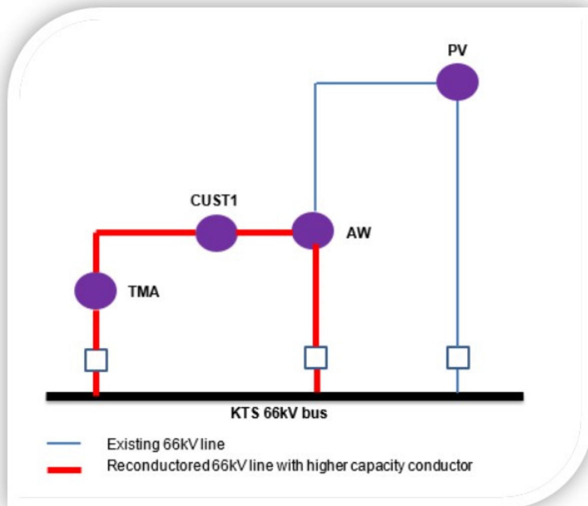
6.2 NETWORK OPTIONS

6.2.1 OPTION 1: RECONDUCTOR KTS-TMA-AW-KTS LOOP

The high level scope for this option includes following:

- Reconductor approximately 19 km of existing KTS-AW, AW-CUST1, TMA-CUST1 and KTS-TMA line with higher capacity conductor (i.e. 61/3.75 AAC);
- Replace existing poles and cross arms with plant suitable for higher capacity conductor;
- Replace transmission connection assets (primary and secondary plant) at KTS, AW, TMA, and CUST1 with higher capacity plant and equipment; and
- Review protection settings of the loop.
- In addition to this scope of works, Jemena would need to develop new design, construction and maintenance standards to integrate a non-standard conductor into the JEN network which would incur additional cost not considered in this analysis and potentially delay implementation of the solution.

Figure 6–1: Option 1: Reconductor KTS-TMA-AW-KTS loop



6.2.2 OPTION 2: NEW KTS-CUST1 66 KV LINE

This option involves converting the existing three legged KTS sub-transmission loop into a four legged loop by installing a new 66 kV line from KTS to CUST1. The high level scope of works for this option includes:

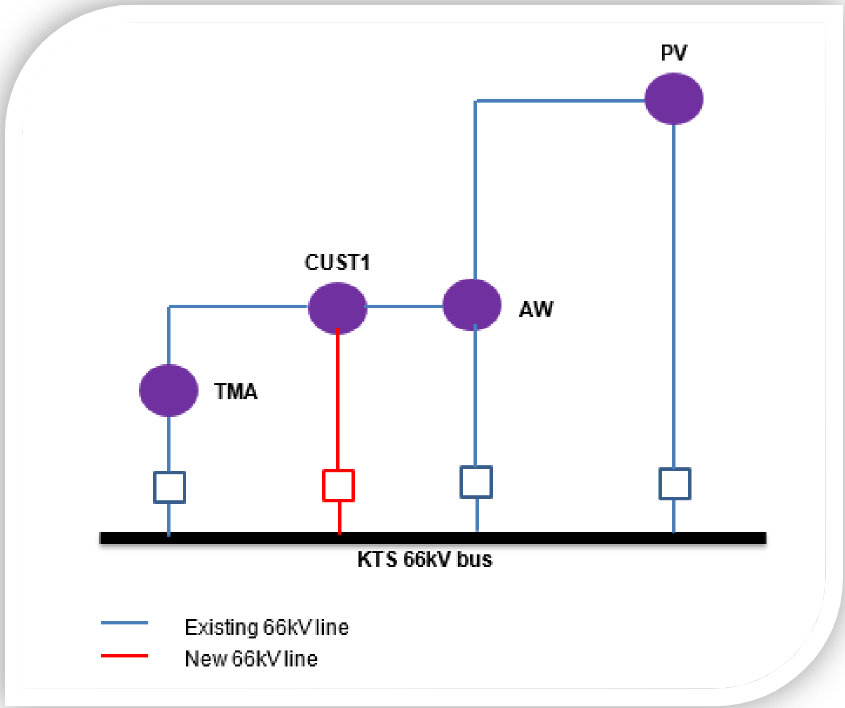
- Install approximately 2.0 km of single core 1200 sq. mm underground cable;
- Install approximately 2.7 km of overhead 66 kV line on the same pole line as existing 22 kV and low voltage lines;
- Install approximately 1.7 km of new 66 kV line;
- Install new 66 kV circuit breakers at KTS and CUST1; and
- Undertake protection and setting reviews for the loop.
- The simplified single line diagram for this option is shown in Figure 6–2.

This option has following limitations:

- Due to limited easement for a new overhead 66 kV line along Keilor park drive, approximately 2 km route length of new line needs to be underground which still depends up on the availability and public consultation. Undergrounding of 66 kV line adds substantial cost to the project.
- Constructing 2.7 km of overhead 66kV line on top of existing 22 kV and low voltage lines requires replacement of the majority of poles to maintain an appropriate ground clearance. This will require extensive outage management works.
- The public consultation required to implement this option will add significant cost and could delay the implementation of the solution.

- To reduce the cost of this option, Jemena considered constructing a section of the new KTS-CUST1 line on the same poles as the existing KTS-TMA line. However, in this case the reliability of the supply would be compromised. For example, if a vehicle hits a pole of the double circuit line, both KTS-TMA and KTS-CUST1 lines will be out of service. In this case, the KTS-AW line will be overloaded, requiring substantial load shed in the loop. The situation will be even worse if a section of the new KTS-CUST1 line was built on the same pole line of the existing KTS-AW.

Figure 6–2: Option 2: New KTS-CUST1 66 kV line



6.2.3 OPTION 3: SPLIT LOOP WITH NEW KTS-CUST1 66 KV LINE

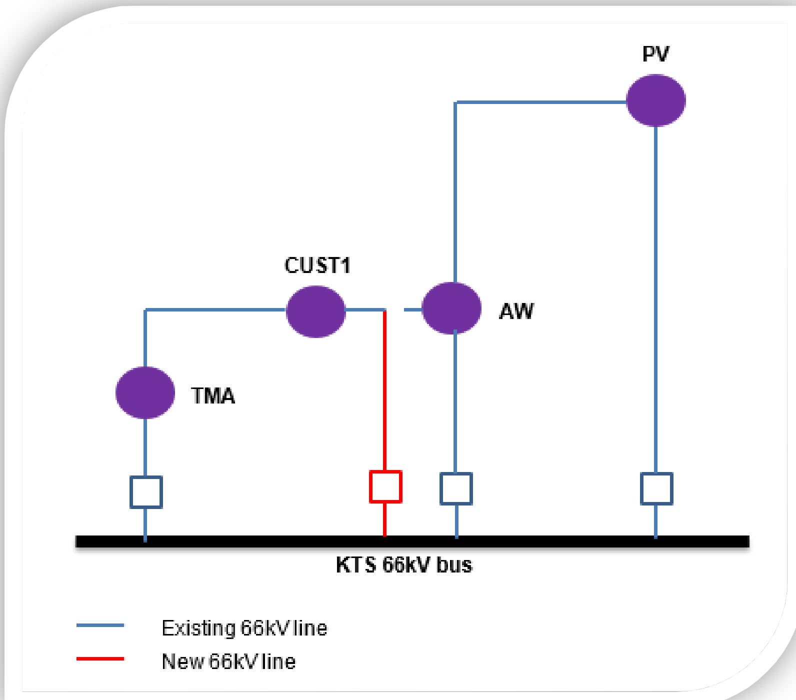
This option involves converting the existing three legged KTS sub-transmission loop into:

- a two legged KTS-AW-PV loop; and
- a two legged KTS-TMA-CUST1 loop.
- The simplified single line diagram for this option is shown in Figure 6–3.
- The high level scope of works for this option includes:
- Install a new 66 kV line on the existing KTS-AW pole line to make it a double circuit which is then connected onto a section of the existing CUST1 - AW 66 kV line to form a new KTS-CUST1 line;
- Establish an additional exit from KTS, being the KTS-CUST1 lines; and
- Modify the protection and control equipment and settings at KTS, TMA, AW and CUST1.

Since the new line will be installed on an existing pole line, less public consultation is required to implement this option and the requirement for new easements is minimised compared to Option 2.

Under Option 3, the N-1 capacity of the KTS-AW-PV loop is limited to 102 MVA. However, it is noted that the summer maximum demand across AW and PV is already approximately 117 MVA so there would already be expected unserved energy on this loop under network outage conditions.

Figure 6–3: Option 3: Split loop with new KTS-CUST1 66 kV line



6.2.4 OPTION 4: SPLIT LOOP WITH NEW KTS-CUST1 AND KTS-AW NO. 2 66 KV LINES

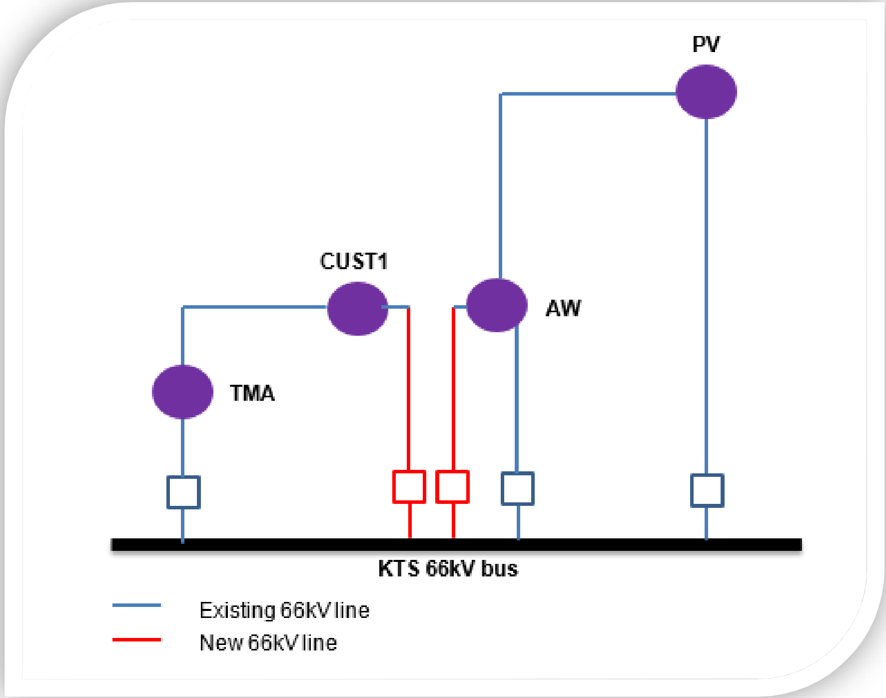
This option involves converting the existing three legged KTS sub-transmission loop into

- a three legged KTS-AW-PV loop; and
- a two legged KTS-TMA-CUST1 loop.
- The simplified single line diagram for this option is shown in Figure 6–4.
- The high level scope of works for this option includes:
- Convert the existing KTS-TMA and KTS-AW single-circuit pole lines to double-circuit pole lines:
  - The second line installed on the existing KTS-TMA pole line will form the KTS-AW No.2 66 kV line; and
  - The second line installed on the existing KTS-AW pole line along with existing sections of AW-CUST1 line will form KTS-CUST1 66 kV line.
- Establish two additional exits from KTS, being the KTS-CUST1 and KTS-AW No.2 lines; and

- Modify the protection and control equipment and settings at KTS, TMA, AW and CUST1.

Since the new two lines will be installed on existing pole lines, less public consultation is required to implement this option and the requirement for new easements is minimised compared to Option 2. There is also sufficient capacity on the KTS-AW-PV loop to meet the forecast maximum demand under network outage conditions.

Figure 6–4: Option 3: Split loop with new KTS-CUST1 and KTS-AW No.2 66 kV lines



6.2.5 SUMMARY OF ADDITIONAL CAPACITY

Table 6–1 summarises the capacity increases which are achieved through each of the network augmentation options described above. Note that the N-1 capacity for Options 1 and 2 is based on the outage of a single 66 kV line within the 3 and 4 legged loop, whereas the N-1 capacity for the Options 3 and 4 considers the outage of two 66 kV lines, one in each of the newly formed loops.

It can be seen that Option 4 delivers the highest N and N-1 capacity increase compared to the base case ("do nothing" option). It is also noted that under Option 3, the N-1 capacity of the KTS-AW-PV-KTS is limited to 102 MVA. However, the summer maximum demand across AW and PV is already approximately 117 MVA so there would already be expected unserved energy on this loop under network outage conditions.

Table 6–1: KTS sub-transmission loop capacity increase for network options

Augmentation option	'N' Capacity (MVA)	'N-1' Capacity (MVA)
Base Case - Do Nothing	261	165
Option 1 – reconductor KTS-TMA-AW-KTS 66 kV loop	341	218
Option 2 – new KTS-CUST1 66 kV line	320	260
Options 3 – split loop with new KTS-CUST1 66 kV line	362 KTS-TMA-CUST1 196 KTS-AW-PV 166	204 KTS-TMA-CUST1 102 KTS-AW-PV 102
Options 4 – split loop with new KTS-CUST1 and KTS-AW No. 2 66 kV lines	480 KTS-TMA-CUST1 196 KTS-AW-PV 284	268 KTS-TMA-CUST1 102 KTS-AW-PV 166

7. MARKET BENEFIT ASSESSMENT METHODOLOGY

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

It also describes the reasonable scenarios considered in comparing the base case 'state of the world' to the credible options considered.

The RIT-D has been assessed over a fifteen year period. Market benefits were calculated for first nine years (2018-2026), based on Jemena's 2016 load demand forecasts, and the ninth year benefits were applied to each of the final six years (2027-2032) of the assessment period. This allows a longer assessment period without the need to develop longer term demand forecasts.

7.1 MARKET BENEFIT CLASSES QUANTIFIED FOR THIS RIT-D

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

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

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

7.1.1 INVOLUNTARY LOAD SHEDDING AND CUSTOMER INTERRUPTIONS

Involuntary load shedding is where a customer's load is interrupted (switched off or disconnected) from the network without their agreement or prior warning. Involuntary load shedding can occur unexpectedly due to a network outage event, or pre-emptively to maintain network loading to within asset capabilities. The aim of a credible option, such as demand side management or a network capacity augmentation, is to provide a change in the amount of involuntary load shedding expected.

A reduction in involuntary load shedding, relative to the Base Case, results in a positive contribution to the market benefits of the credible option being assessed. The involuntary load shedding of a credible option is derived by:

- The quantity (in MWh) of involuntary load shedding required assuming the credible option is completed, multiplied by
- The value of customer reliability (in $/MWh), which Jemena has calculated to be $39,440/MWh based on AEMO's Value of Customer Reliability review[6].
- Jemena forecasts and models hourly load for the forward planning period, and quantifies the expected unserved energy (involuntary load shedding) by comparing forecast load to network capabilities under system normal and network outage conditions.

6 AEMO Value of Customer Reliability review. Available http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

- Jemena has captured the reduction in involuntary load shedding as a market benefit of the credible options assessed in this RIT-D. The costs have been included in the net economic benefit assessments summarised in Section 8.

7.1.2 TIMING OF EXPENDITURE

The long term costs of credible options assessed in this RIT-D include all the major works on the KTS sub-transmission loop currently considered likely within the fifteen year period of 2018-2032. The costs used to rank credible options are the total lifecycle cost of each credible option, rather than just the immediate project works that this RIT-D is aiming to justify.

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

7.2 MARKET BENEFIT CLASSES NOT RELEVANT TO THIS RIT-D

This section outlines the classes of market benefits that Jemena considers immaterial to this RIT-D assessment, and our reasoning for their omission from this RIT-D assessment.

The market benefits that Jemena considers will not materially impact the outcome of this RIT-D assessment include changes in:

- Network losses
- Costs to other parties;
- Load transfer capacity and embedded generators; and
- Option value.

7.2.1 NETWORK LOSSES

When conducting network analysis for each of the options to derive estimates of unserved energy, Jemena has also determined the network losses. For each option under consideration in this assessment, the increased capacity will lead to a reduction in electrical losses.

As Option 3 is the option with the highest increase in conductor capacity, it is expected that this option will also result in the lowest network losses. Further, as can be seen in Section 8.1.2, Option 3 has the highest NPV. Therefore, while an indicative estimate of market benefits associated with a change in network losses has been quantified by Jemena for each of the options, a more comprehensive determination of network losses, for each option over the 15 year assessment period, has not been completed, as it will not alter the preferred option. Jemena has therefore chosen not to include these benefits in this assessment.

7.2.2 VOLUNTARY LOAD CURTAILMENT

Voluntary load curtailment is where a customer/s agrees to voluntarily curtail their electricity under certain circumstances, such as high network loading or during a network outage event. The customer will typically receive an agreed payment for making load available for curtailment, and for actually having it curtailed during a network event. A credible demand-side reduction option leads to a change in the amount of voluntary load curtailment.

- The non-network options screening assessment presented in Section 5 concluded that a demand response solution to defer the preferred network augmentation was not cost effective or practical. As such, market benefits associated with voluntary load curtailment have not been considered in the detailed options analysis presented in Section 8.

7.2.3 COSTS TO OTHER PARTIES

The KTS sub-transmission loop capacity constraint is a localised thermal capacity limitation on the Jemena network that supplies the Tullamarine, Airport West and Pascoe Vale areas. The network limitation is on the sub-transmission network which is downstream of the transmission network and neither the impacted zone substations nor their high voltage feeders supply or connect to networks of other parties. As such, none of the credible options are expected to have a material impact on any surrounding areas or on the network development plans of any other network participants or other parties. Jemena has therefore not attempted to quantify any market benefits associated with costs to other parties.

7.2.4 CHANGES IN LOAD TRANSFER CAPACITY AND EMBEDDED GENERATORS

Load transfer capacity between Tullamarine and Airport West Zone Substations is predominately limited by the high voltage feeders that connect between the two zone substations. There is no load transfer capability between Pascoe Vale and Airport West substations, as the Pascoe Vale network operates at 11 kV, whereas the Airport West network operates at 22 kV. Options that address the capacity constraints on the sub-transmission loop won't change feeder or load transfer capacities. Options that could result in a load transfer capacity change are those that address capacity limitations along, or downstream of, the high voltage feeders. This could include feeder augmentations or reconfigurations, demand side management or embedded generation.

Jemena is aware that the two major customers (CUST1 and CUST2) which are supplied from the KTS sub-transmission loop, have significant generation facilities on their sites. However, the primary purpose of this generation is to provide back-up to critical infrastructure in the event of a network outage. The non-network screening analysis presented in Section 5, indicated that even if the full capacity of these embedded generators was available for network support, it would be insufficient to defer the network augmentation for 1 year without some risk of unserved energy. Even if there was sufficient embedded generation, the annual cost of network support payments would significantly exceed the deferral value of the preferred network option. As such, the market benefits associated with embedded generators have not been considered in the detailed options assessment presented in Section 8. Nevertheless, Jemena will continue to work with these major customers to identify opportunities to manage the network risk ahead of the network augmentation.

7.2.5 OPTION VALUE

Jemena notes the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change.

We also note the AER's view that appropriate identification of credible options is capable of capturing any option value, thereby meeting the requirement to consider option value as a class of market benefit under the RIT-D.

In addition to appropriate identification of credible options, Jemena has undertaken sensitivity studies on the forecast demand, value of customer reliability, discount rate, and credible option capital costs. Any calculation of option value benefit beyond this would require significant modelling, which is expected to be disproportionate to any additional option value benefit that may be identified. Jemena has therefore not attempted to estimate any additional option value market benefit for this RIT-D assessment.

7.3 VALUING MARKET BENEFITS

Clause 5.17.1 of the NER requires that the RIT-D assessment is based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand. Since this RIT-D is driven by electricity demand in a predominately radial network with minimal demand side generation, future supply developments are not expected to significantly impact the assessment results, preferred option or optimal timing.

As described in Section 3.1, Jemena has elected to assess three alternative demand scenarios:

- Planning demand growth – demand on the KTS sub-transmission loop assumed to be as forecast in the 2016 Distribution Annual Planning Report (DAPR);
- Moderate demand growth – demand at TMA, AW and PV assumed to be as forecast in the 2016 DAPR. In addition, the two major customers, CUST1 and CUST2, are assumed to reach their contracted demand by 2026; and
- Fast demand growth – demand at TMA, AW and PV assumed to be as forecast in the 2016 DAPR. In addition, the two major customers, CUST1 and CUST2, are assumed to reach their contracted demand by 2021;

In each of the three alternative demand scenarios, the summer and winter peak demand has been forecast for 10% POE and 50% POE conditions. In valuing market benefits for this RIT-D, the demand forecasts have been weighted 30% for the 10% POE demand forecasts and 70% for the 50% POE demand forecasts. The complete set of demand forecasts are tabulated in Appendix A.

7.3.1 SENSITIVITY ANALYSIS

There are three key inputs that could potentially vary the optimal timing or preferred option for mitigating the KTS sub-transmission loop limitations. Sensitivity studies to these key inputs have been assessed under each of the alternative demand scenarios. The preferred option is the one that maximises the present value of net economic benefit in the majority of reasonable scenarios and sensitivity studies.

The key variables applied in valuing the sub-transmission network limitations and economic benefits are outlined in this section, and include:

- Value of customer reliability (VCR);
- Discount rate; and
- Project costs.

7.3.1.1 Value of customer reliability

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

In assessing the credible options to alleviate the impact of constraints on its network, Jemena applies VCR values based on the Australian Energy Market Operator's (AEMO) 2014 Value of Customer Reliability Review[7]. Applying the sectorial values developed by AEMO to Jemena's load composition of approximately 47% commercial, 31% residential and 22% industrial customers, Jemena determined a VCR of $39,440/MWh (in 2016 Australian dollars), which includes an escalation factor of 1.33% to account for CPI from AEMO's 2014 to 2015 value, and

[7] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

1.25% to account for CPI from the 2015 to 2016 value. The same VCR of $39,440/MWh derived in 2016 has been applied in this DPAR as the base VCR.

Sensitivities to the base VCR of ±20% have been considered, resulting in a low VCR sensitivity of $31,552/MWh and a high VCR of $47,328/MWh.

7.3.1.2 Discount rate

A discount rate of 6.37% has been applied in undertaking the Net Present Value (NPV) assessment of credible options.

Although lower than Jemena considers appropriate for the analysis of a private enterprise investment in the electricity sector, this discount rate is based on the AER’s approved weighted average cost of capital (WACC) for Jemena’s electricity network in 2016.

Jemena has applied a sensitivity discount rate of 8.26%. This accounts for uncertainty surrounding annual changes to the AER approved WACC.

7.3.1.3 Project costs

The network project capital costs have been estimated by Jemena’s internal estimation teams. Consideration has been given to recent similar augmentation projects and expected costs based on site specific construction complexities and industry experience. These project estimates have been prepared for planning purposes and are therefore subject to an estimate range of ±30%, which has therefore been applied to the sensitivity studies for this RIT-D.

Operational and maintenance costs for the network projects are estimated at ±1.5% of capital cost per annum.

Project costs are real $2017. A consumer price index (CPI) rate of 2.5% per annum has been applied to the project works planned in later years.

8. OPTIONS ANALYSIS

This section presents the base case limitation and summarises the augmentation analysis results of potential options. The annualised limitation cost for the Base Case (Do Nothing) and each of the four network augmentation options is presented for the next nine year period, as is the net economic benefit calculated for each potential option. The net economic benefit analysis has been assessed considering the network risk and expected augmentation costs for the fifteen year period from 2018 to 2032.

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

8.1 NETWORK LIMITATIONS

This section presents the annualised limitation cost for the next nine year period, due to the thermal and reliability limitations for the base case "do-nothing" option and each of the network augmentation options.

Consistent with the 2016 DAPR, the determination of energy at risk for the KTS sub-transmission loop is determined as follows:

- Conduct network studies to determine the flow observed on the remaining in service sub-transmission lines, for an outage of one line.
- Where the post contingent flow on the remaining in service lines exceeds 120% of the line rating, determine the pre-contingency load reduction required such that the post contingent flow does not exceed 120% of the line rating. To determine the expected energy at risk, this pre-contingency load reduction has a probability of one.
- The expected energy at risk to reduce flow for the remaining in service line from 120% to 100% of the line ratings is determined from the additional load shed required and the contingency probability for the relevant line outage.

In practise, load shedding prior to an outage would be a last resort for Jemena operations staff. However, this must be balanced against the risk of damage to the remaining in service line if an outage were to occur, resulting in a flow significantly about the line rating.

8.1.1 BASE CASE

If no action is taken to increase the supply capacity or voluntarily reduce the demand on the KTS sub-transmission loop, involuntary load shedding would be required under system normal and network outage conditions.

The impact of the network limitations for the Base Case ("do nothing" option) under the three demand growth scenarios is presented in Table 8–1 to Table 8–3.

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Table 8–1: Limitation impact under Base Case – planning demand growth scenario

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	6.5	21.8	18	0	1
2019	11.7	27.2	28	0	15
2020	17.3	33.0	38	3	124
2021	17.4	33.7	41	4	141
2022	21.1	38.4	51	10	377
2023	26.7	44.0	59	22	873
2024	30.2	47.9	63	40	1,573
2025	36.6	56.0	79	104	4,106
2026	39.7	58.8	89	143	5,635

Table 8–2: Limitation impact under Base Case – moderate demand growth scenario

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	12.4	28.0	28	0	17
2019	20.8	36.4	45	6	252
2020	29.7	45.6	61	29	1,138
2021	34.0	50.0	71	54	2,133
2022	41.4	58.0	99	128	5,050
2023	50.6	67.0	213	297	11,708
2024	57.7	74.4	417	513	20,227
2025	67.7	85.9	1302	978	38,556
2026	75.1	91.6	2158	1,622	63,957

Table 8–3: Limitation impact under Base Case – fast demand growth scenario

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	22.3	37.8	50	8	300
2019	35.7	51.1	73	61	2,415
2020	50.0	65.3	202	267	10,509
2021	60.2	76.0	546	549	21,635
2022	62.7	79.0	633	661	26,087
2023	67.0	83.0	762	857	33,787
2024	68.7	85.4	852	980	38,634
2025	73.6	91.7	1058	1,330	52,443
2026	75.5	92.9	1195	1,622	63,957

8.1.2 NETWORK OPTIONS

Table 8–4 summarises the network limitations expected by 2026 for each of the credible network options considered under the three demand growth scenarios (refer to Appendix B for full details). Note the following:

- While the MVA load at risk for Option 1 is not inconsequential, the expected unserved energy is low because the reconductored lines are assumed to have a much higher rating (160 MVA) such that the overload under network outage conditions remains within 120% of the line rating.
- There is no expected unserved energy for Option 2. However, if the new KTS-CUST1 66 kV line is constructed along the same poles as the existing KTS-AW 66 kV line the reliability of the supply will be compromised. For example if a vehicle hits a pole of the double circuit, both lines will be out of service. For this double circuit outage, the expected unserved energy would be the same as observed for the base case, do nothing scenario.
- For Option 3 there is sufficient capacity for the newly formed two legged KTS-TMA-CUST1-KTS loop through to 2021 and it is only marginally exceeded through to 2026 under all growth scenarios. However, there is insufficient capacity for the newly formed two legged KTS-AW-PV-KTS loop, with significant levels of expected USE from 2018. Note the expected USE for this option is the same for all three demand growth scenarios because both CUST1 and CUST2 are supplied from the KTS-TMA-CUST1-KTS loop. Furthermore, the expected USE for Option 3 is in fact higher than the ”do nothing” base case under the planning demand growth scenario.
- For Option 4 there is no expected USE for the newly formed three legged KTS-AW-PV-KTS loop for a single outage condition. Although the network capacity on the KTS-TMA-CUST1-KTS loop is exceeded from 2021 under single outage condition, assuming fast demand growth scenario, the magnitude of the overload is small and the expected USE is marginal.

Table 8–4: Limitation impact of network options

Network Option	Cost of weighted expected unserved energy in 2026 ($k)		
	Planning demand growth	Moderate demand growth	Fast demand growth
Base Case - Do Nothing	5,635	63,957	63,957
Option 1 – reconductor KTS-TMA-AW 66 kV loop	0	396	396
Option 2 – new KTS-CUST1 66 kV line	0	0	0
Options 3 – split loop with new KTS-CUST1 66 kV line	9,459	9,459	9,459
Options 4 – split loop with new KTS-CUST1 and KTS-AW No. 2 66 kV lines	0	1	1

8.2 ECONOMIC BENEFITS

Net economic benefits are the market benefits less the cost (negative benefit) to implement the credible option being considered. Table 8–5 shows the cost, net economic benefit, and the project ranking of each option relative to the Base Case ("Do Nothing" option). The feasible options have been ranked based on their present value of net economic benefit, which is the total benefits provided over the 2017-2032 period, minus the project cost to implement, operate and maintain the credible option being considered.

The assessment results show that the option that maximises the net economic benefit is Option 4. This option involves splitting the KTS sub-transmission loop by installing two new 66 kV lines, KTS-CUST1 and KTS-AW, by November 2019. This option is Jemena's proposed preferred option because it meets the identified need and maximises the net economic benefit compared to all the other options considered in this RIT-D.

Table 8–5: Market benefits of augmentation options relative to the base case

Network option	Project cost (2018-2032) ($M)	NPV of net economic benefit ($M)			Project ranking
		Planning growth	Moderate growth	Fast growth	
Base Case - Do Nothing	0	-20.1	-266.3	-342.6	5
Option 1 – reconductor KTS-TMA-AW 66 kV loop	13.08	6.1	250.4	322.2	2
Option 2 – new KTS-CUST1 66 kV line	15.38	3.6	249.4	321.3	3
Options 3 – split loop with new KTS-CUST1 66 kV line	5.65	-34.2	211.2	282.8	4
Options 4 – split loop with new KTS-CUST1 and KTS-AW No. 2 66 kV lines	10.43	8.9	254.6	326.6	1

The sensitivity analysis also shows that Option 4 maximises the net economic benefit under all cases considered. The sensitivity analysis results are included in Appendix C spreadsheets.

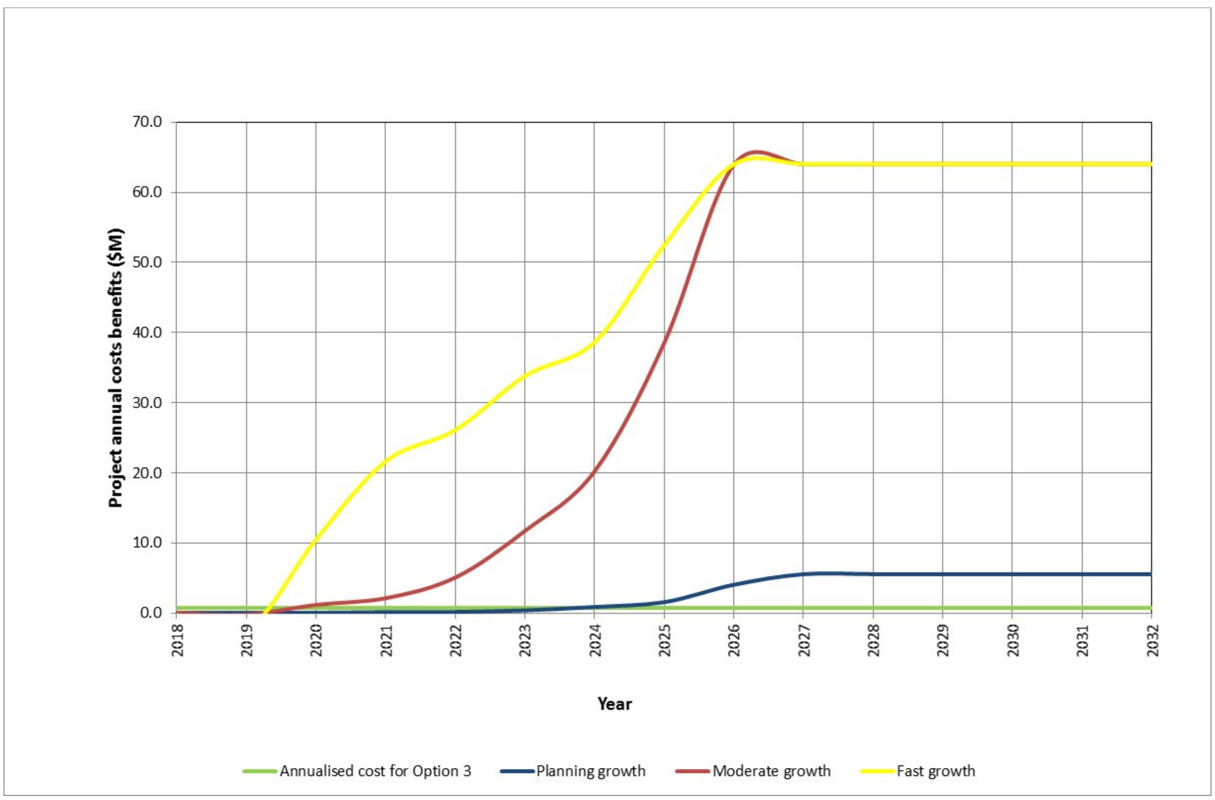
8.3 PREFERRED OPTION OPTIMAL TIMING

The optimal timing of works associated with the Option 4 works have been identified by taking the annualised augmentation market benefit (the change in voluntary and involuntary load shedding) associated with undertaking the proposed augmentation, and comparing it to the annualised cost of establishing, operating and maintain the proposed network augmentation from 2018. The annualised capital cost of augmentation is calculated using the project costs, a project life of fifty years, and a discount rate of 6.37% per annum.

The annualised cost of the proposed preferred option, Option 4, is $745 thousand.

As shown in Figure 8–1, the annualised benefit exceeds the annualised cost by 2020 for both the moderate and fast demand growth scenarios. Therefore the optimal timing to complete the network augmentation is expected to be November 2019. Under the unlikely scenario that CUST1 and CUST2 decided not to proceed with their requests to increase contracted demand, network augmentation would still be justified by November 2022 (i.e. under 2016 DAPR forecasts, the annualised benefit of Option 2 exceeds the annualised cost by 2023).

Figure 8–1: Annualised costs and benefits of Option 4



9. CONCLUSION AND NEXT STEPS

9.1 PREFERRED SOLUTION

The options analysis identifies that Option 4 - split the existing 66 kV loop by installing new KTS-CUST1 and KTS-AW No. 2 66 kV lines is the preferred network augmentation option as it is shown to:

- Have the highest net present value for JEN customers of all options under all demand growth scenarios considered; and
- Achieve the capital expenditure objective(s) as per the National Electricity Rules (NER) Section 6.5.7, by increasing the sub-transmission loop capacity to meet expected demand and maintain the quality, reliability and security of supply for standard control service in the supply area.

Table 9–1 shows the total project cost breakdown for Option 4 delivered by November 2019. Applying the discount rate of 6.37% per year, this preferred solution has a net economic benefit of $255 million (Real $2017) over the fifteen year assessment period under a moderate demand growth scenario.

Table 9–1: Option 4 - Cost estimate breakdown

	NPV project cost ($M Real2017)
Network augmentation capital cost	10.96
Network augmentation operational and maintenance cost	0.20
Total project expenditure	11.16

9.2 NEXT STEPS

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

All submissions and enquiries should be directed to:

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Network Capacity Planning & Assessment Manager
Email: PlanningRequest@jemena.com.au
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Submissions must be lodged with us on or before 21 August 2017.

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

Following our consideration of any submissions on this Draft Project Assessment Report, we will proceed to prepare a Final Project Assessment Report (FPAR). That report will include a summary of, and commentary on, any submissions to this report and present the final preferred solution to address the KTS sub-transmission loop thermal capacity constraint. Publishing the FPAR will be the third and final stage in the RIT-D process.

We intend to publish the FPAR by 4 September 2017. Note that if no submissions are received on this report, we will discharge our obligation to publish the FPAR, and instead include the final decision in the 2017 Distribution Annual Planning Report.

APPENDIX A: MAXIMUM DEMAND FORECASTS

This Appendix A presents the maximum demand forecasts for Tullamarine (TMA), Airport West (AW), and Pascoe Vale (PV) Zone Substations as used in Jemena's 2016 Distribution Annual Planning Report (DAPR).

Table A–1: TMA maximum demand forecasts.

Year	Summer 50% POE demand (MVA)	Winter 50% POE demand (MVA)	Summer 10% POE demand (MVA)	Winter 10% POE demand (MVA)
2018	20.2	16.8	22.0	17.2
2019	23.2	19.6	25.3	20.0
2020	25.8	22.0	28.1	22.5
2021	25.9	22.1	28.2	22.6
2022	26.6	22.7	29.1	23.3
2023	27.6	23.6	30.1	24.2
2024	28.2	24.2	30.8	24.8
2025	29.3	25.3	32.2	25.9
2026	30.0	26.4	32.7	27.1

Table A–2: AW maximum demand forecasts.

Year	Summer 50% POE demand (MVA)	Winter 50% POE demand (MVA)	Summer 10% POE demand (MVA)	Winter 10% POE demand (MVA)
2018	84.5	66.6	92.0	68.2
2019	85.0	67.2	92.6	68.8
2020	86.5	68.6	94.1	70.1
2021	86.3	68.6	94.0	70.2
2022	88.1	70.2	96.3	71.9
2023	90.9	72.5	99.0	74.2
2024	92.4	74.0	100.9	75.8
2025	95.6	76.9	104.8	78.7
2026	97.2	79.8	106.2	81.8

Table A–3: PV maximum demand forecasts.

Year	Summer 50% POE demand (MVA)	Winter 50% POE demand (MVA)	Summer 10% POE demand (MVA)	Winter 10% POE demand (MVA)
2018	33.1	26.7	38.0	27.4
2019	33.2	26.9	38.1	27.6
2020	33.1	26.9	37.9	27.5
2021	32.2	26.2	37.0	26.8
2022	32.2	26.3	37.1	26.9
2023	32.5	26.6	37.3	27.2
2024	32.3	26.5	37.2	27.2
2025	32.7	27.0	37.8	27.6
2026	32.6	27.4	37.5	28.1

APPENDIX B: LIMITATION IMPACT

Option 1: Reconductor KTS-TMA-AW-KTS loop

The expected network limitations for Option 1 under:

- Planning demand growth scenario are presented in Table B–1;
- Moderate demand growth scenario are presented in Table B–2; and
- Fast demand growth scenario are presented in Table B–3.

Table B–1: Limitation impact for Option 1 – Planning demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	0.0	0.0	0	0	0
2019	0.0	0.0	0	0	0
2020	0.0	0.0	0	0	0
2021	0.0	0.0	0	0	0
2022	0.0	0.0	0	0	0
2023	0.0	1.1	1.0	0	0
2024	0.0	5.0	2.0	0	0.02
2025	0.0	8.9	3.0	0	0.05
2026	0.0	12.3	5.5	0	0.1

Table B–2: Limitation impact for Option 1 – Moderate demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	2.6	1	0	0
2021	0	6.0	2	0	0
2022	0	14.2	7	0	0
2023	6.4	23.6	16	0	1
2024	12.8	31.0	26	0	1
2025	22.5	43.1	44	3	127
2026	30.1	45.2	47	10	396

Table B–3: Limitation impact for Option 1 – Fast demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	0.0	0.0	0	0	0
2019	0.0	7.6	2	0	0
2020	4.9	21.7	13	0	0
2021	13.8	31.1	26	0	1
2022	16.6	34.5	29	0	2
2023	21.2	38.4	35	1	34
2024	23.1	41.0	38	2	92
2025	28.0	47.6	53	7	269
2026	30.1	45.2	47	10	396

Option 2: New KTS-CUST1 66 kV line

There is no expected unserved energy under the planning, moderate or fast demand growth scenarios.

Option 3: Split loop with new KTS-CUST1 66 kV line

The expected network limitations for Option 3 under planning, moderate and fast demand growth scenarios are presented in Table B–4 (i.e. same expected unserved energy under all three demand growth scenarios);

Table B–4: Limitation impact for Option 4 – planning, moderate and fast demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50POE	10POE			
2018	17.9	30.5	63	32	1,262
2019	18.8	31.2	67	36	1,423
2020	20.4	32.6	66	51	2,015
2021	19.2	31.5	64	44	1,715
2022	20.9	34.4	76	66	2,615
2023	24.2	37.1	80	110	4,339
2024	25.6	39.3	90	138	5,460
2025	29.5	43.0	95	219	8,626
2026	31.3	44.1	117	240	9,459

Option 4: Split loop with new KTS-CUST1 and KTS-AW No. 2 66 kV lines

The expected network limitations for Option 4 under:

- Moderate demand growth scenario are presented in Table B–5; and
- Fast demand growth scenario are presented in Table 6–1.

There is no expected unserved energy under the planning growth scenario.

Table B–5: Limitation impact for Option 3 – Moderate demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	2.2	2	0	0
2025	1.9	6.4	7	0	0
2026	7.1	11.9	18	0	1

Table B–6: Limitation impact for Option 3 – Fast demand growth

Year	Max load at risk under system normal condition (MW)		Annual hours at risk under system normal conditions (h)	Weighted expected unserved energy (MWh)	Cost of weighted expected unserved energy ($k)
	50% POE	10% POE			
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	2.5	7.9	9	0	0
2022	3.3	8.0	9	0	0
2023	4.6	8.1	9	0	0
2024	5.5	9.2	12	0	1
2025	6.7	11.0	16	0	1
2026	7.1	11.9	18	0	1

APPENDIX C: ECONOMIC ASSESSMENT SPREADSHEETS

Load at risk assessments are included as Microsoft Excel spreadsheet attachments.

These spreadsheet attachments show the annual expected unserved energy, between 2018 and 2032, that would remain following implementation of each potential option considered.

The spreadsheet attachments include:

- RIT-D Cost-Benefit Assessment – planning demand growth scenario
- RIT-D Cost-Benefit Assessment – moderate demand growth scenario
- RIT-D Cost-Benefit Assessment – fast demand growth scenario