Regulatory Investment Test for Distribution

Final Project Assessment Report

Addressing Reliability Requirements in the Cape River Network Area

Publication Date: 13 **March 2020**

Part of Energy Queensland

Executive Summary

ABOUT ERGON ENERGY

Ergon Energy Corporation Limited (Ergon Energy) is part of Energy Queensland and manages an electricity distribution network which supplies electricity to more than 765,000 customers. Our vast operating area covers over one million square kilometres – around 97% of the state of Queensland – from the expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with associated infrastructure such as major substations and power transformers.

We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland which are not connected to the main electricity grid.

IDENTIFIED NEED

Cape River 66/11kV Substation (CARI) is an integral node in the North Queensland mid-west 66kV sub transmission network which supplies 4,102 customers (directly and indirectly) and two major renewable generation projects in the Hughenden area.

CARI was built in the mid-1960s and a significant portion of the primary plant is now at or approaching the assessed end of life based on age and condition. CARI consists of four 66kV feeder bays, a 66kV voltage regulator, a 66/11kV 1MVA power transformer and two outdoor 11kV feeder bays.

Based on a Condition Based Risk Management analysis of the effect of current condition and ageing on the expected life of the asset, the following have been deemed to reach retirement age:

- The 66/11kV 1MVA transformer (YOM 1954) is 65 years old and is poor condition.
- The C152 (CT-CR-1 Fdr) and D152 (CR-HU-1 Fdr) 66kV circuit breakers are of ABB HLC type. These are part of a REPEX replacement program due to a known potentially explosive failure mode. The roller contacts on ABB HLC circuit breakers of the same make and model at other sites in the network have failed. The hazard exists if there is insufficient contact pressure between the moving contact and the roller contact frame if one or more of the roller contacts is / are missing with the circuit breaker in the closed position. This may lead to arcing across this point resulting in generation of gas bubbles and an increase in internal pressure within the circuit breaker with the pressure causing eventual failure of the circuit breaker.
- There are approximately ten 66kV timber pole isolator structures and a number of other timber pole support structures for the 66kV overhead bus. The condition of the poles is not known, however site photos show that a number of the timber poles at this site are supported by pole nails.
- Additionally, asbestos has been identified in the internal walls, ceiling, soffit and external walls of the control building at CARI. Ergon Energy has a strategy to remove all

asbestos containing materials from our assets, to minimise staff and contractor exposure to respirable asbestos fibres.

The deteriorated condition of the assets at Cape River Substation poses significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Cape River Substation.

The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Cape River Substation in order to maintain a safe, reliable supply of electricity to customers in the Cape River region.

APPROACH

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Ergon Energy has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Cape River supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Ergon Energy published a Notice of no non-network options for the above described identified need on 13 December 2019.

Two potentially feasible options have been investigated:

- **Option A:** Rebuild of Cape River Substation within the new Cape River East site and decommissioning the existing Cape River Substation.
- **Option B:** Replacement of the aged assets at Cape River Substation.

This Final Project Assessment Report (FPAR), where Ergon Energy provides both technical and economic information about possible solutions has been prepared in accordance with the requirements of clause 5.17.4(o) of the NER. Ergon Energy's preferred solution to address the identified need is Option A - Rebuild of Cape River Substation within the new Cape River East site and decommissioning the existing Cape River Substation.

1 Introduction

This FPAR has been prepared by Ergon Energy in accordance with the requirements of clause 5.17.4(o) of the NER.

This report represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need in the Cape River network area.

In preparing this RIT-D, Ergon Energy is required to consider reasonable future scenarios. With respect to major customer loads and generation, Ergon Energy has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Ergon Energy is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Structure of this report

This report:

- Identifies the need which Ergon Energy is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.2. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5(a) of the NER, Registered Participants or Interested Parties may, within 30 days after the publication of this report, dispute the conclusions made by Ergon Energy in this report with the Australian Energy Regulator. Accordingly, Registered Participants and Interested Parties who wish to dispute the conclusions outlined in this report based on a manifest error in the calculations or application of the RIT-D must do so within 30 days of the publication date of this report. Any parties raising a dispute are also required to notify Ergon Energy. Dispute notifications should be sent to demandmanagement@ergon.com.au

If no formal dispute is raised, Ergon Energy will proceed with the preferred option to rebuild the Cape River Substation within the new Cape River East site and decommissioning the existing Cape River Substation.

1.3. Contact Details

Inquiries about this RIT-D may be sent to:

E: demandmanagement@ergon.com.au

P: 13 74 66

2 Background

2.1. Geographic Region

The geographic region covered by this RIT-D is Cape River Substation and the connected substations through its 66kV Network. Cape River Substation is located approximately 200km South-West of Townsville near the township of Pentland in the Mid-West area of the Northern Region of Ergon Energy’s Network.

Figure 1 Mid-West 66kV sub transmission Network

2.2. Existing Supply System

CARI is supplied via two 66kV feeders from Charters Towers (Charters Towers – Cape River and Millchester – Cape River feeders). The substation directly and indirectly supplies approximately 4,102 premises, 295 of these from the local 11kV distribution feeders and the remainder from the outgoing 66kV sub-transmission network which supplies Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton substations.

The geographical location of the mid-west area substations and sub-transmission feeders are shown in the diagram below:

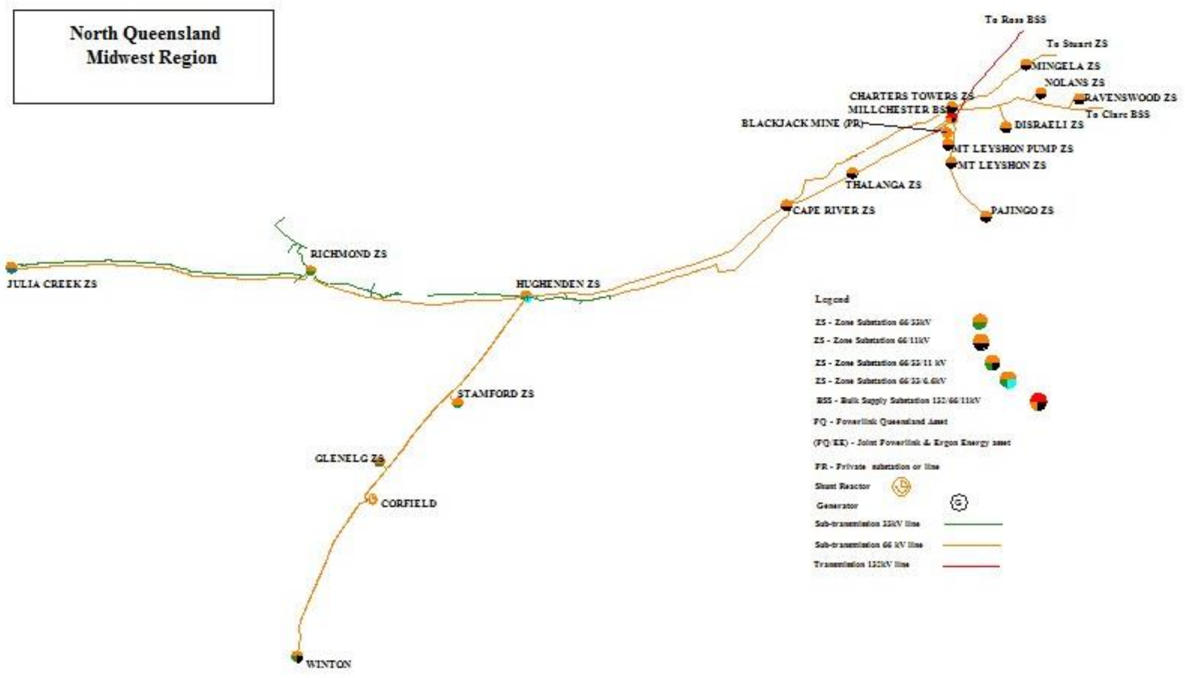

Figure 2 Geographical locations of Substations and Sub-Transmission Network in the NQ Mid-West Region

There are currently significant works under development on the Ergon network in this area as part of a generator connection project. These works include the establishment of two 132/66/33kV substations, Cape River East Substation (CPRE) which will be located adjacent to Cape River Substation and Jardine Creek Substation (JACR) which will be located approximately 20km east of Hughenden. A section of the Cape River – Hughenden 66kV feeder, which is predominantly a 132kV construction, will be energised at 132kV between CPRE and JACR substations.

The CPRE substation layout has been designed to cater for the future retirement of the CARI substation with an allowance for additional 66kV feeder bays and a spare 33kV indoor bay for the connection of a 33/11kV power transformer.

Figure 3 Aerial image showing the location of CPRE in relation to the existing CARI site

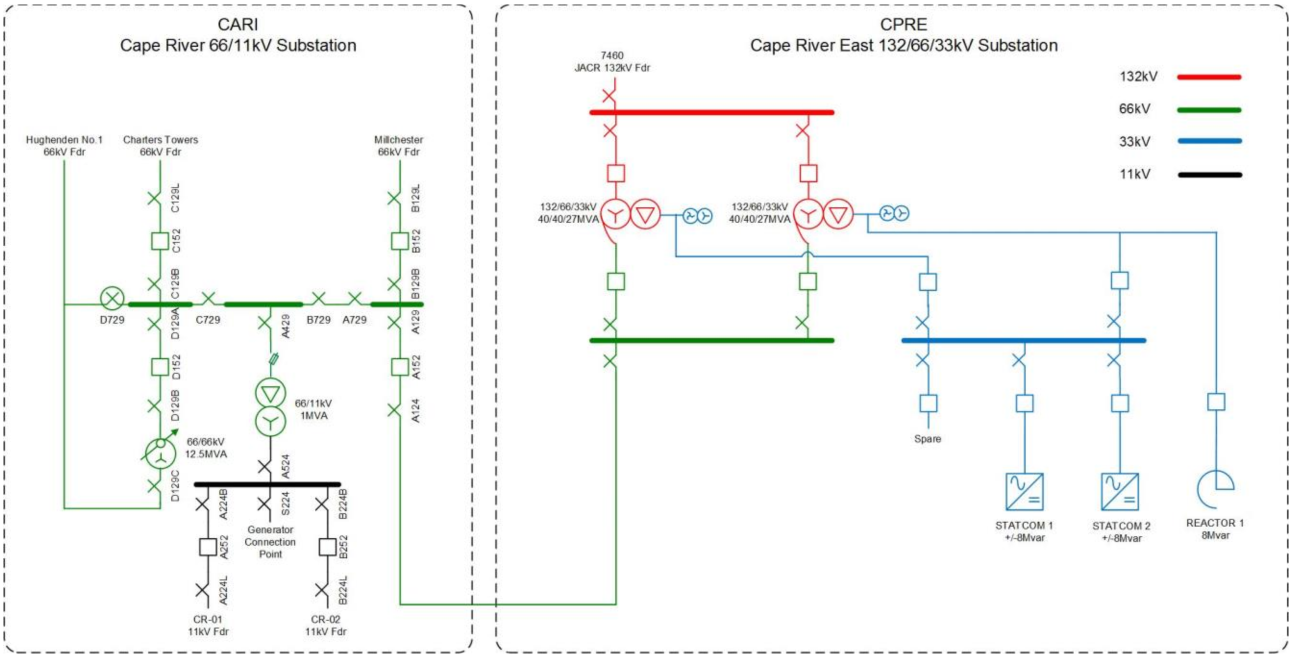

Figure 4 Single Line Diagram of CARI and CPRE substations

2.3. Load Profiles / Forecasts

2.3.1. Cape River subtransmission feeder forecasts

Feeder Name	Year / Ratings Period / Variable	2019 SD	2019 SE	2019 SNM	2020 SD	2020 SE	2020 SNM	2021 SD	2021 SE	2021 SNM	2022 SD	2022 SE	2022 SNM	2023 SD	2023 SE	2023 SNM
CR-HU-1	% of Rated A	26.4	43.8	34.5	24.9	42.6	33.6	25.0	42.7	33.7	26.0	43.0	34.3	26.4	43.4	34.6
	Loading (A)	31	70	54	29	68	52	29	68	53	30	69	54	31	69	54
	Power Factor	0.63	0.69	0.71	0.64	0.70	0.72	0.63	0.70	0.72	0.62	0.70	0.71	0.63	0.70	0.71
	Rating (A)	116	160	156	116	160	156	116	160	156	116	160	156	116	160	156
CR-HU-2	% of Rated A	16.6	34.8	29.7	15.7	33.8	28.9	15.8	33.9	29.0	16.3	34.2	29.5	16.7	34.5	29.8
	Loading (A)	31	71	55	30	69	53	30	70	54	31	70	55	31	71	55
	Power Factor	0.77	0.80	0.82	0.78	0.81	0.83	0.78	0.80	0.83	0.77	0.80	0.82	0.77	0.80	0.82
	Rating (A)	188	205	185	188	205	185	188	205	185	188	205	185	188	205	185
CT-CR-1	% of Rated A	26.0	39.6	36.5	25.3	38.7	35.8	25.3	38.8	35.9	25.8	39.0	36.4	26.1	39.3	36.6
	Loading (A)	48	79	66	46	77	64	47	78	65	47	78	66	48	79	66
	Power Factor	0.54	0.74	0.68	0.53	0.73	0.68	0.53	0.73	0.68	0.53	0.74	0.68	0.54	0.74	0.68
	Rating (A)	184	200	180	184	200	180	184	200	180	184	200	180	184	200	180
MR-CR-1	% of Rated A	43.9	49.6	41.4	42.5	48.4	40.5	42.6	48.6	40.6	43.5	49.0	41.3	44.0	49.3	41.5
	Loading (A)	68	114	94	66	111	92	66	111	92	67	112	93	68	113	94
	Power Factor	0.88	0.94	0.92	0.87	0.93	0.91	0.87	0.93	0.91	0.88	0.94	0.91	0.88	0.94	0.92
	Rating (A)	155	229	226	155	229	226	155	229	226	155	229	226	155	229	226

Table 1 Sub transmission Feeder Forecast and Ratings from 2018 DAPR[1]

The table above shows the system normal forecast loadings and ratings from the 2018 Distribution Annual Planning Report for the 66kV feeders that connect to Cape River substation. It is important to note that this forecast hasn't allowed for the additional loading expected from the new generation projects in the mid-west area.

2.3.2. Mid-West Area Substation Forecasts

The plots below show the historical maximum demands and the 50% Probability of Exceedance (50 PoE) forecast demands for the Cape River Substation 11kV load and the substations supplied from the Cape River 66kV feeders.

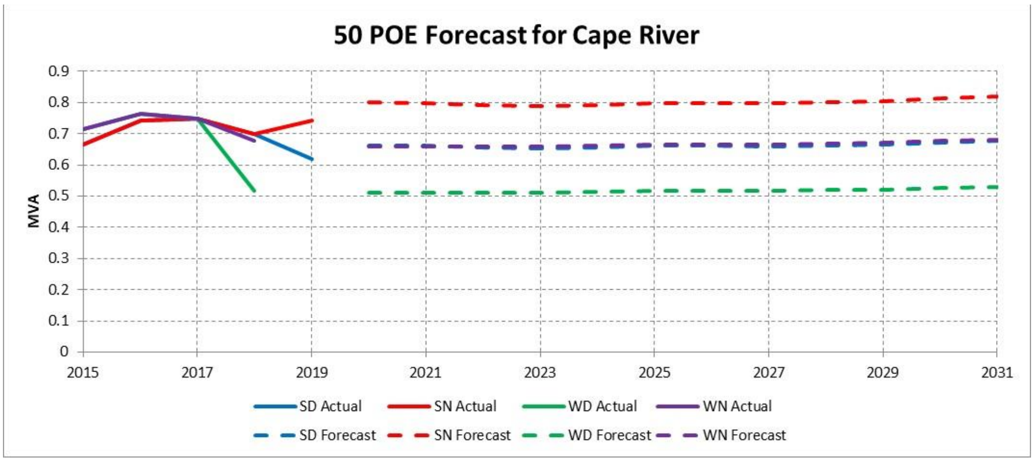

Figure 5 50 PoE Demand Forecast for the Cape River Substation 11kV load

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[1] https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report. Note that the ratings of the feeders presented in this table are currently being reviewed and therefore may not provide an accurate representation of the actual ratings.

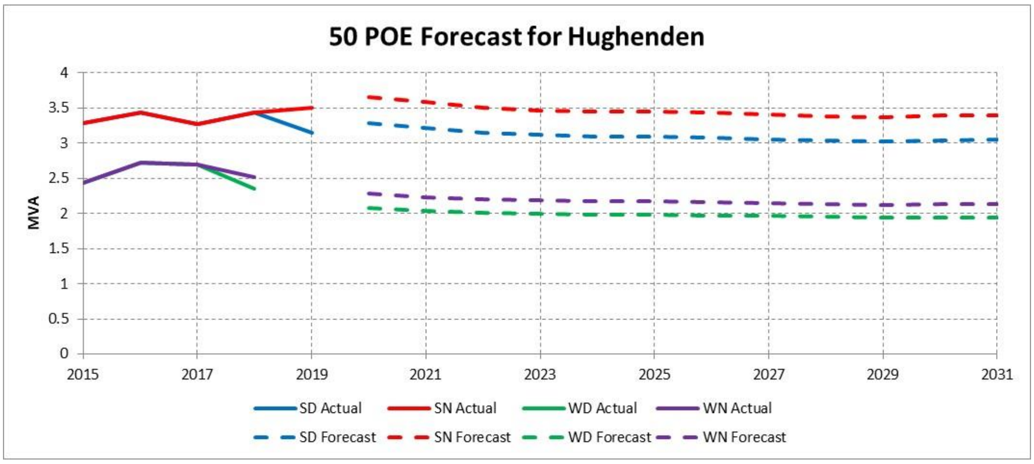

Figure 6 50 PoE Demand Forecast for the Hughenden Substation 33kV load

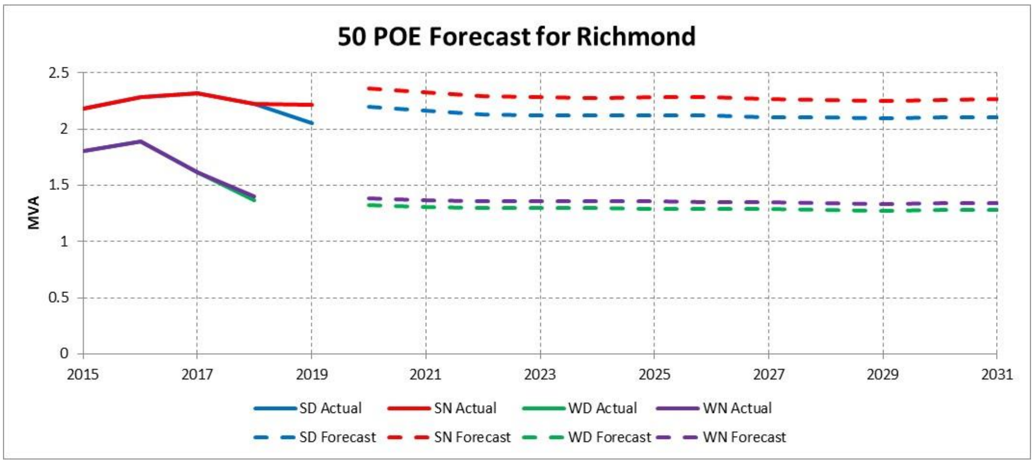

Figure 7 50 PoE Demand Forecast for the Richmond Substation 33kV load

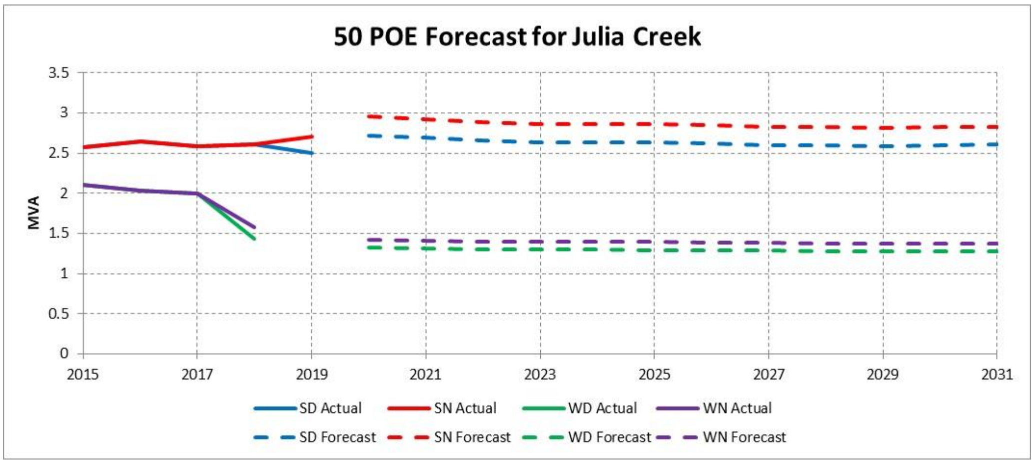

Figure 8 50 PoE Demand Forecast for the Julia Creek Substation 33kV load

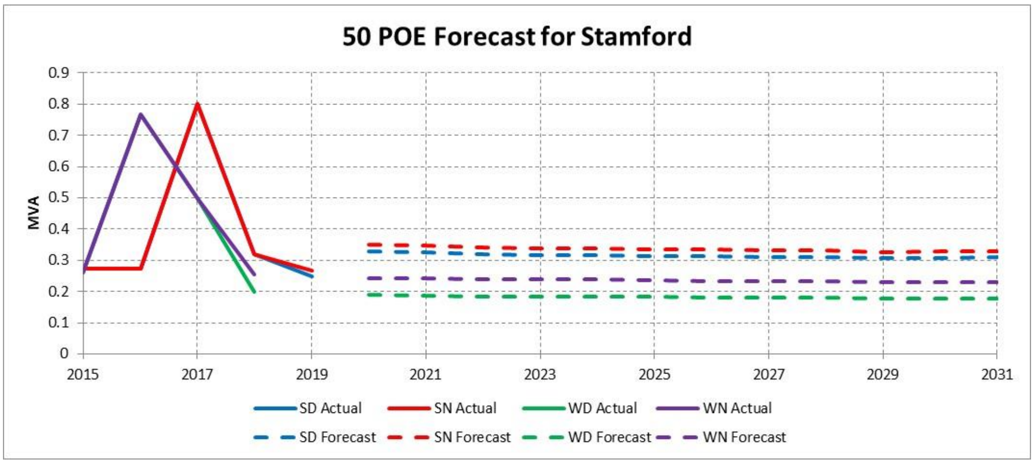

Figure 9 50 PoE Demand Forecast for the Stamford Substation 33kV load

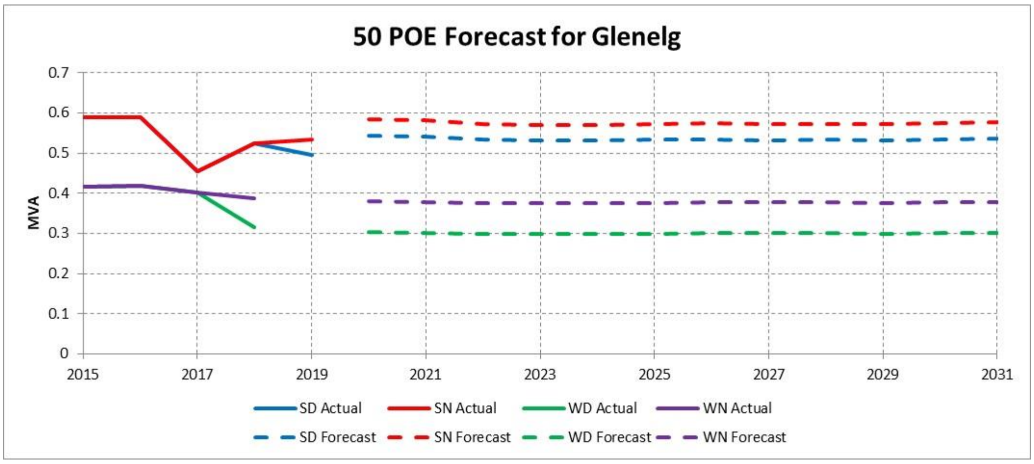

Figure 10 50 PoE Demand Forecast for the Glenelg Substation 33kV load

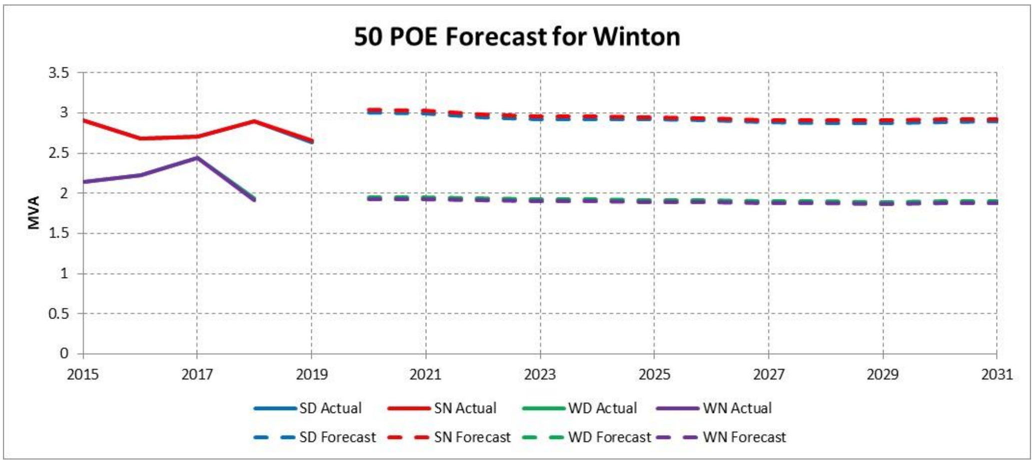

Figure 11 50 PoE Demand Forecast for the Winton Substation 11kV load

As shown in the plots above there is minimal forecast load growth at Cape River Substation and the other mid-west substations supplied via Cape River substation including Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton.

Although there is minimal load growth it is important to note that there are currently two renewable energy projects under development in the mid-west area which will substantially increase the loading on the sub transmission network between Charters Towers and Hughenden.

2.3.3. Cape River Substation load profiles

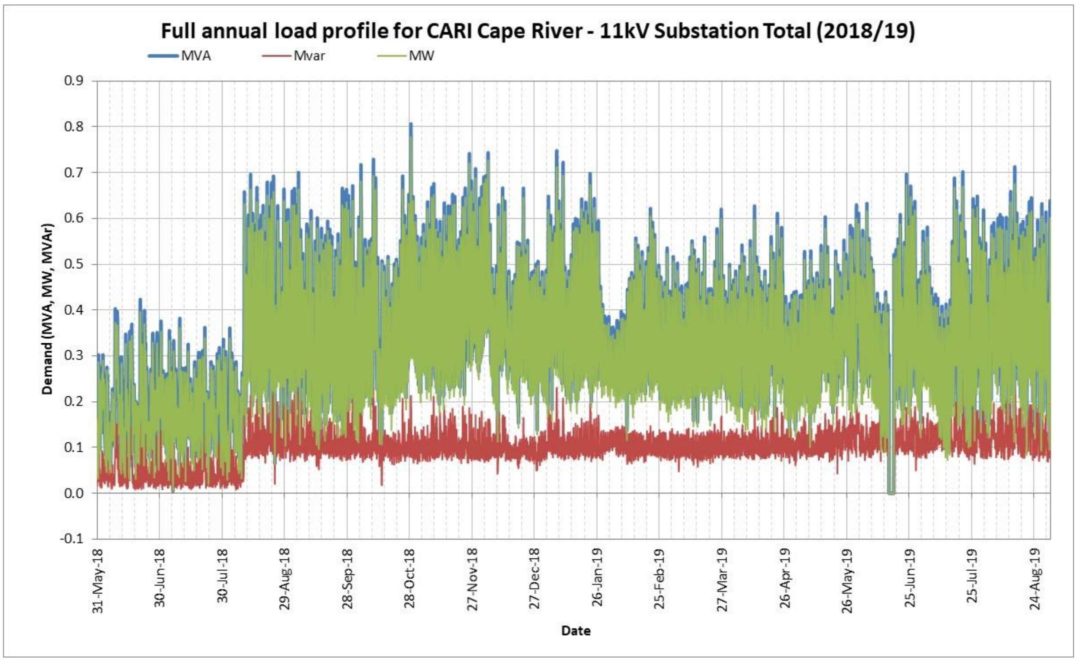

Figure 12 CARI 11kV load profile (2018/19)

The plot above shows the half hourly average daily load profile for Cape River Substation 11kV load for the 2018/19 period. Note that the data shown in the plot prior to July 2018 is incorrect due to a metering issue.

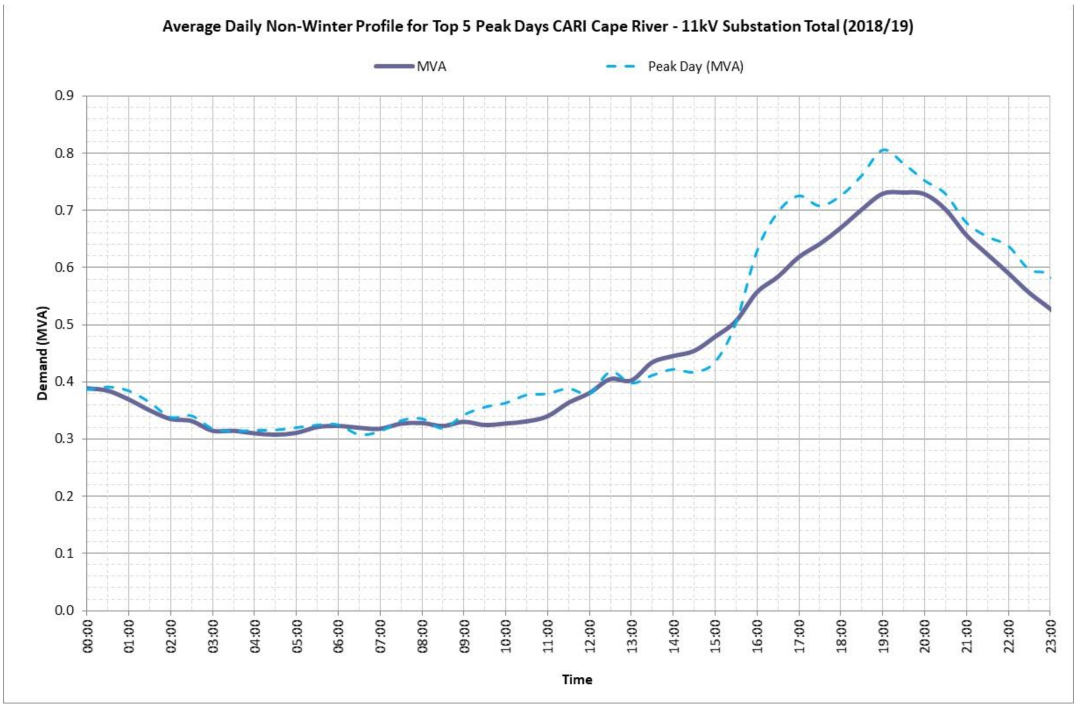

Figure 13 CARI 11kV load profile – Average of Top 5 Peak Days (2018/19)

The summer peak for the Cape River Substation 11kV load typically occurs in the early evening as shown in the plot above.

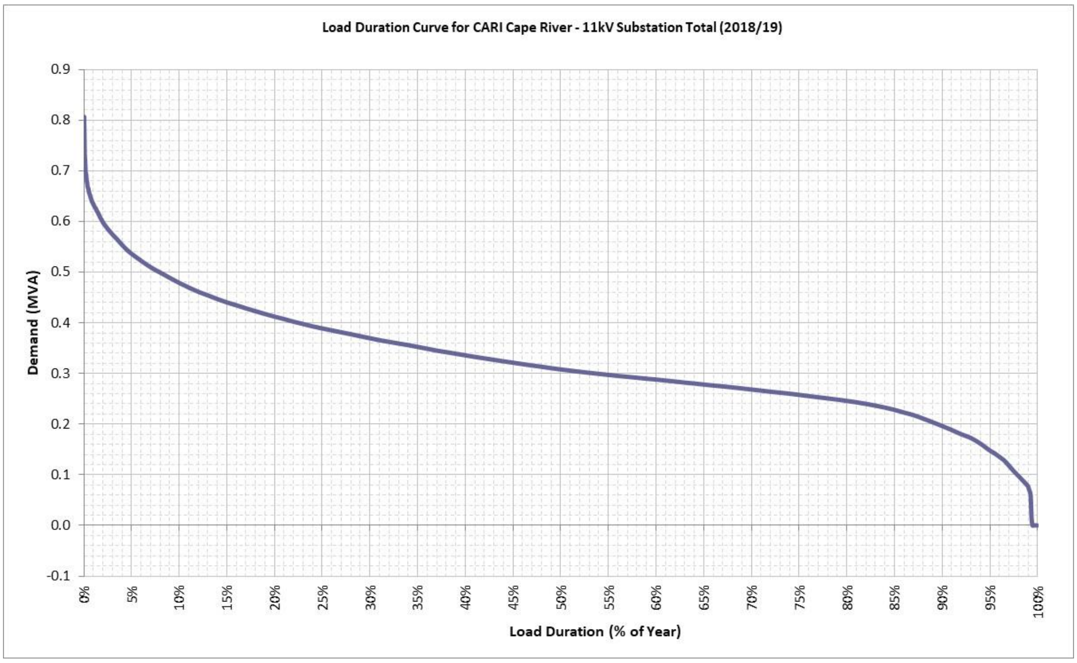

Figure 14 CARI 11kV Load Duration Curve (2018/19)

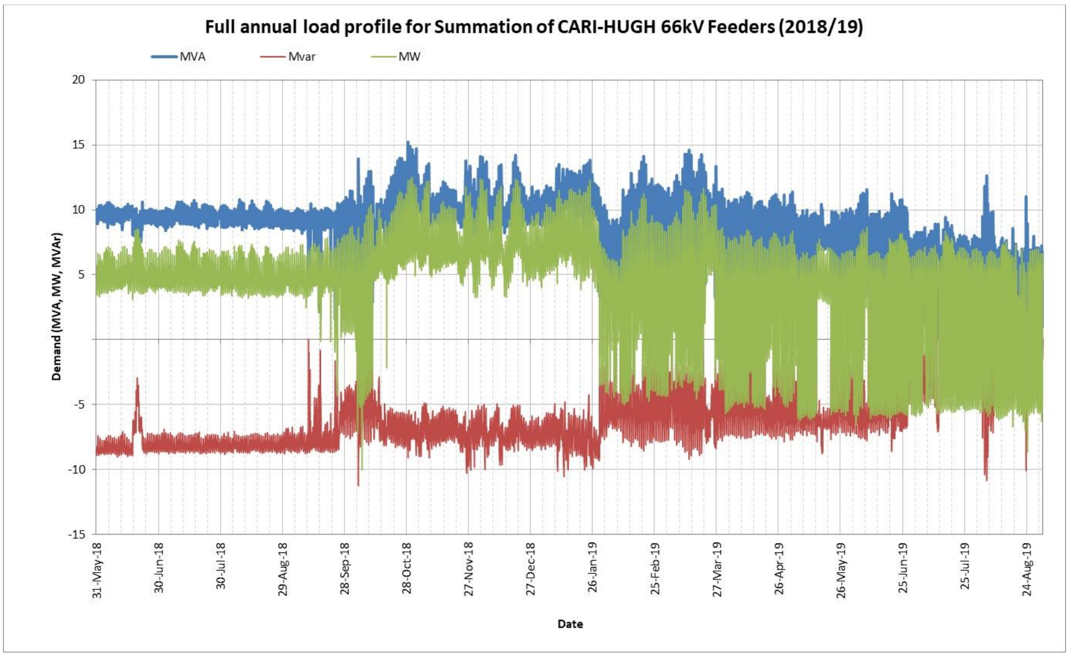

Figure 15 Summated CARI-HUGH 66kV feeders load profile (2018/19)

The plot above shows the half hourly average daily load profile for the summation of the CARI-HUGH 66kV feeders for the 2018/19 period. The change in power flows from positive to negative is due to export from one of the new generators in the mid-west area.

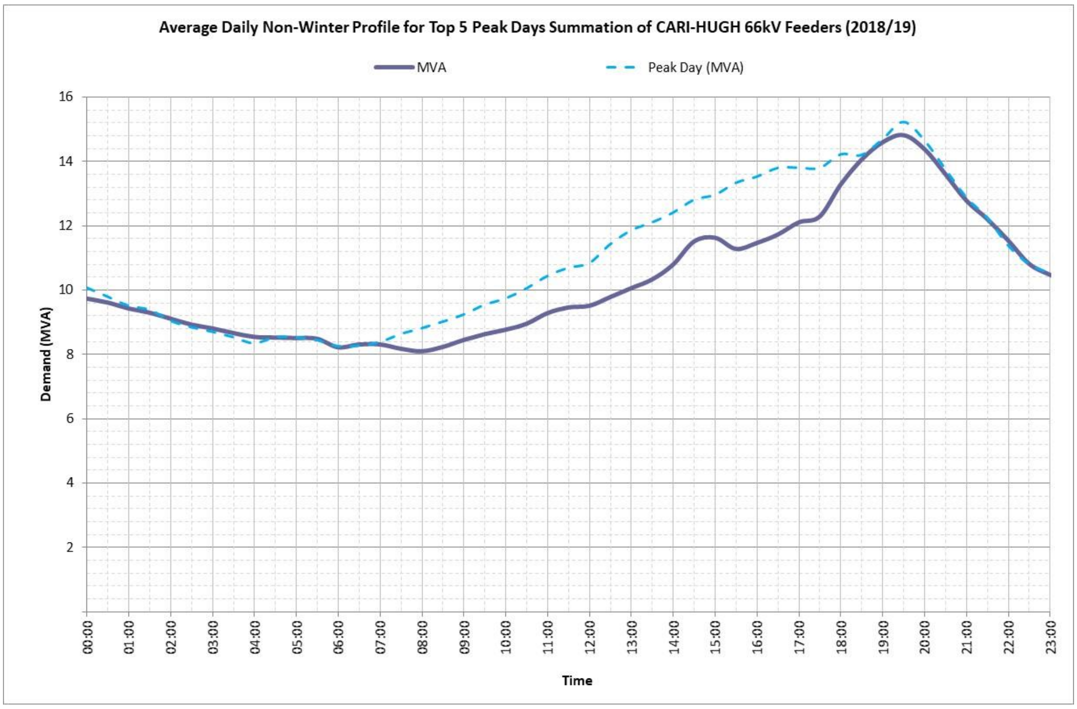

Figure 16 Summated CARI-HUGH 66kV feeders load profile – Average of Top 5 Peak Days (2018/19)

The summer peak for the summation of the CARI-HUGH 66kV feeders load typically occurs in the early evening as shown in the plot above. The average daily load profile for these feeders will change after the new generators in the mid-west area are fully operational.

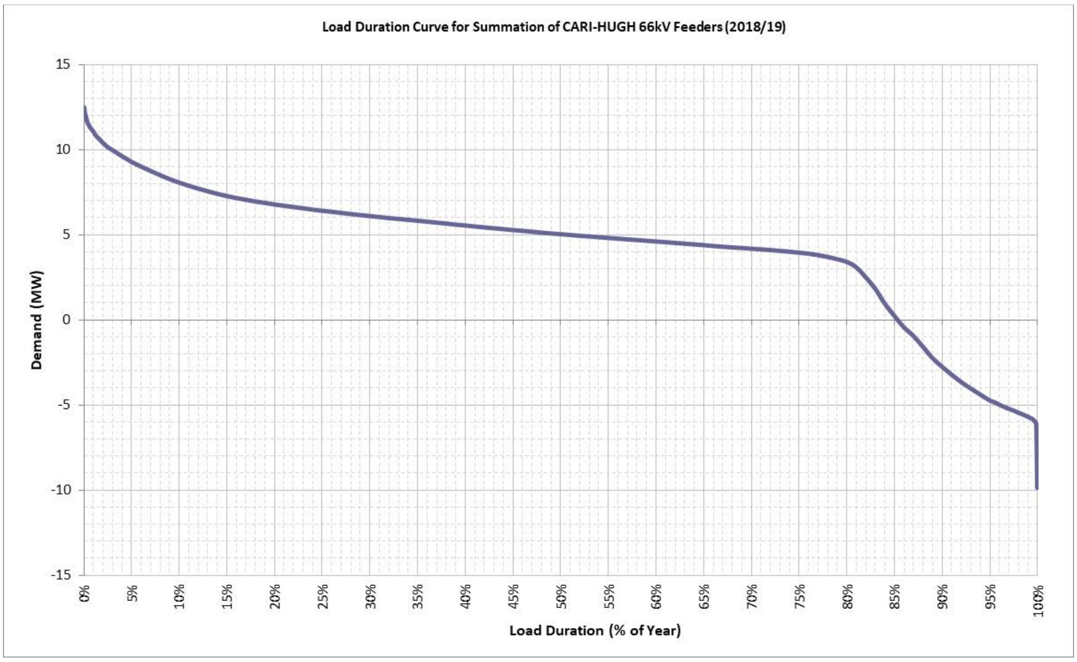

Figure 17 Summated CARI-HUGH 66kV feeders Load Duration Curve (2018/19)

3 Identified Need

3.1. Description of the Identified Need

CARI was built in the mid-1960s and a significant portion of the primary plant is now at or approaching the assessed end of life based on age and condition. CARI consists of four 66kV feeder bays, a 66kV voltage regulator, a 66/11kV 1MVA power transformer and two outdoor 11kV feeder bays.

Based on a Condition Based Risk Management analysis of the effect of current condition and ageing on the expected life of the asset, the following have been deemed to reach retirement age:

- The 66/11kV 1MVA transformer (YOM 1954) is 65 years old and is poor condition.
- The C152 (CT-CR-1 Fdr) and D152 (CR-HU-1 Fdr) 66kV circuit breakers are of ABB HLC type. These are part of a REPEX replacement program due to a known potentially explosive failure mode. The roller contacts on ABB HLC circuit breakers of the same make and model at other sites in the network have failed. The hazard exists if there is insufficient contact pressure between the moving contact and the roller contact frame if one or more of the roller contacts is / are missing with the circuit breaker in the closed position. This may lead to arcing across this point resulting in generation of gas bubbles and an increase in internal pressure within the circuit breaker with the pressure causing eventual failure of the circuit breaker.
- There are approximately ten 66kV timber pole isolator structures and a number of other timber pole support structures for the 66kV overhead bus. The condition of the poles is not known, however site photos show that a number of the timber poles at this site are supported by pole nails.
- Additionally, asbestos has been identified in the internal walls, ceiling, soffit and external walls of the control building at CARI. Ergon Energy has a strategy to remove all asbestos containing materials from our assets, to minimise staff and contractor exposure to respirable asbestos fibres.

The deteriorated condition of the assets at Cape River Substation poses significant safety risks to staff working in proximity to these assets and reliability of supply risks to customers supplied from Cape River Substation.

The identified need for investment is to remediate the safety and reliability risks currently associated with the aged assets at Cape River Substation in order to maintain a safe, reliable supply of electricity to customers in the Cape River region.

3.2. Quantification of the Identified Need

3.2.1. Increased risk of involuntary load shedding going forward

Failure of the single 66/11kV transformer at CARI would result in an outage to approximately 295 customers.

A sustained 66kV bus fault at CARI would result in loss of supply to at least 4,102 customers and two major generators. This includes loss of supply to entire rural towns such as Hughenden, Richmond, Julia Creek and Winton.

In the event of a 66/11kV transformer failure or 66kV bus fault at CARI Ergon Energy will use 'best endeavours' to restore supply deploying generation for the case of a transformer fault or isolation/repair of the faulted bus section for the case of a 66kV bus fault.

Although CARI is in a remote location, it has been assumed that generation can be deployed to restore supply to the Cape River 11kV network within 13 hours and for a majority of bus faults supply can typically be fully restored within 8 hours. The restoration times would generally be dependent on a number of factors including location of staff, time of fault, severity of the fault, asset accessibility, availability of suitable spares, weather conditions and would vary under extenuating circumstances such as a natural disaster scenario.

Figure 18 Photo showing pole nails on the 66kV supporting structures at CARI

Based on the existing peak load profiles at CARI the load at risk over a 24-hour period would be in the order of 190MWh for a 66kV outage and 10.4MWh for a 11kV outage. Based on the assumed restoration times and generation deployment these figures would reduce to around 63.2MWh and 5.6MWh.

Based on Condition Based Risk Management analysis the probability of failure of 66kV primary plant (i.e. HLC circuit breaker) that would lead to a 66kV bus outage could occur as infrequently as once in 4.5 years. The average annual probability of failure (PoF) is therefore 0.22 and the estimated unserved energy in the next 10 years is estimated at 140MWh.

Based on Condition Based Risk Management analysis the probability of a 66/11kV transformer failure that would lead to an outage to the local 11kV distribution network could occur as infrequently as once in 20 years. The average annual probability of failure (PoF) is therefore 0.05 and the estimated unserved energy in the next 10 years is estimated at 2.8MWh.

3.3. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.3.1. Forecast Maximum Demand

It has been assumed that maximum demand at Cape River Substation and the other mid-west substations supplied via Cape River substation including Hughenden, Richmond, Julia Creek, Stamford, Glenelg and Winton will have minimal growth over the next 10 years as per the forecasts in Section 2.3.2.

Although there is minimal load growth it is important to note that there are currently two renewable energy projects under development in the mid-west area which will substantially increase the loading on the sub transmission network between Charters Towers and Hughenden.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history
- known future developments (new major customers, network augmentation, etc.)
- temperature corrected start values (historical peak demands)
- forecast growth rates for organic growth

3.3.2. Load Profile

It has been assumed that the average daily substation load profiles shown in Section 2.3.3 will not change substantially over the coming years. Although the assumption is that there will be minimal change, the load profiles could potentially be influenced by changes to customer generation or usage patterns and the uptake of electric vehicles and battery storage in the area.

The average daily load profile for the 66kV feeders shown in section 2.3.3 will change after the new generators in the mid-west area are fully operational.

4 Credible Options Assessed

4.1. Assessment of Network Solutions

Ergon Energy investigated a number of network options to address the identified need at Cape River Substation. Details of the credible options are presented in the following sections.

4.1.1. Option A: Rebuild of Cape River Substation within the new Cape River East site

Option A involves the installation of a 33/11kV transformer, 66kV feeder bays, 11kV feeder bays and associated protection and control equipment at the adjacent Cape River East Substation and decommissioning the existing Cape River Substation.

The full scope of works to be covered by Option A is as follows:

<u>Works at CPRE Substation:</u>

- 2 x new outdoor 66kV feeder bays.
- CBs, CTs, VTs and line isolator to be installed in existing outdoor 66kV feeder bay.
- Extend switchyard including earth grid to allow for the installation of the 33/11kV transformer and outdoor 11kV feeder bays.
- 1 x 33/11kV 3MVA Dyn1 transformer with OLTC.
- UG cable from transformer to 33kV switch board.
- Outdoor 11kV bus, 1 x outdoor 11kV transformer bay, 2 x 11kV outdoor feeder bays, 11kV feeder tie isolator and 1 x 11kV generation connection point.
- New separate control building containing:
    - 66kV and 11kV feeder panels;
    - Communications and control panels;
- Relocate / reroute communications equipment from CARI to CPRE.
    - Communications pole and associated antennas (Mt Misery link, P25 radio)
    - Ubinet infrastructure and panels

<u>CARI Substation:</u>

- Decommission substation and remove redundant 66/11kV transformer, regulator, switchgear, CTs, VTs, isolators, structures, control building, footings, fencing, etc

<u>66kV and 11kV feeders:</u>

- Reroute Millchester, Charters Towers and Hughenden No.1 66kV feeders across to new bays at CPRE;
- Reroute CR-01 and CR-02 11kV feeders across to new bays at CPRE;
- Recover redundant line assets as far as practical.

The Single Line Diagram of CPRE substation below in Figure 19 shows the proposed network option.

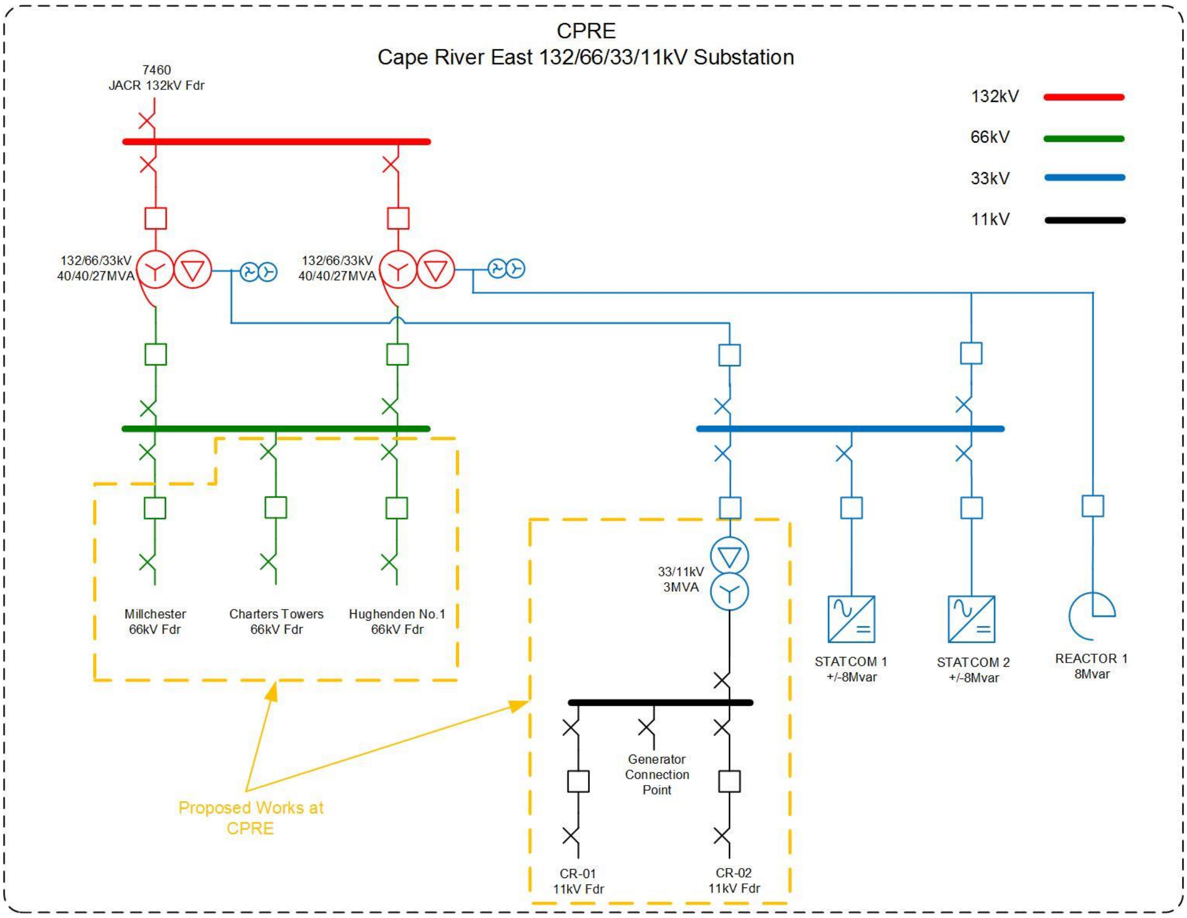

Figure 19 Single Line of CPRE showing proposed network option

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $8.78 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The proposed project timeline has design commencing in 2020/2021 and construction completed by 2022/2023.

4.1.2. Option B: Replacement of the aged assets at Cape River Substation

Option B involves the replacement of aged assets at the existing Cape River Substation site.

The full scope of works to be covered by Option B is as follows:

<u>CARI Substation:</u>

- Replacement of the C152 & D152 66kV ABB HLC CBs and structures;
- Replacement of the 66/11kV power transformer and upgrades to bunding and oil containment system;
- Replacement of 25kVA pole mounted station service transformer;
- Replacement of 10 x 66kV isolators (replacement of the B729, C729, D729, A429, B129L, C129L, C129B, D129A, D129B & D129C isolators mounted on timber pole structures with new isolators mounted on concrete pole or steel structures);
- Upgrade the 66kV bus including replacement of timber pole structures with concrete pole or steel structures including any required lightning protection.
- Removal of asbestos from the CARI control building and yard.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $6.5 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The proposed project timeline has design commencing in 2020/2021 and construction completed by 2022/2023.

4.2. Assessment of Non-Network Solutions

Ergon Energy's Demand & Energy Management team has assessed the potential non-network alternative options required to defer the network option and determine if there is a viable demand management option to replace or reduce the need for the network options proposed.

4.2.1. Customer Energy efficiency and power factor correction

Energy efficiency and power factor correction while offering permanent reductions has been assessed as not technically viable as this would only contribute to a fraction of the support required for the Cape River Substation load.

4.2.2. Demand Response (curtailment of load)

Customer curtailment of load is an effective technique for network support where the need is for a short time period but is generally not viable for extended periods of time.

A small portion of the Cape River Substation residential load such as hot water systems, pool pumps and air conditioning is controllable load that can be switched off for short periods of time.

In the mid-west region large customer demand response is valued at $40-100 per kVA (excluding acquisition costs).

Targeted DM during the peak load periods on the Cape River 11kV network, if successful could reduce the size of the proposed 33/11kV transformer.

After the connection of the new generation projects to the mid-west sub-transmission network the Cape River 66kV feeders will reach their highest utilisation levels during the light load / peak generation scenarios. A reduction in demand would further increase these utilisation levels on the sub transmission network during peak generation scenarios.

These options have been assessed as technically not viable as they would not provide the identified demand reduction required at Cape River Substation and the load reduction would only be available for short periods of time.

4.2.3. Customer Solar Power / Energy Storage Systems

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS).

There are currently around 572 customers connected to the mid-west network with inverter energy systems installed with a combined capacity of approximately 3645kVA.

At present, only a very small percentage of customer solar power systems are coupled with a BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when network support is required.

This option has been assessed as technically not viable as it would not provide the identified demand reduction required to support the Cape River Substation loads, would only provide support during daylight hours and the majority of these systems cease to operate during a network outage.

4.2.4. Large-Scale Customer Generation / Energy Storage

Large scale customer generation or energy storage is an effective technique for network support where the need is for a short time period but is generally not viable for extended periods of time.

In the mid-west region large customer generation support is valued at $40-100 per kVA (excluding acquisition costs). Note that this option commonly sources existing standby generators that can be operated in parallel with the network or separated from the network in an islanded arrangement to supply the customer's facility.

Although the renewable energy projects under development in the mid-west area may possess the levels of generation support required to supply the mid-west loads, this option has been assessed as technically not viable as it is considered unlikely that these generators could supply the entire mid-west load on an enduring basis and maintain the required levels of reliability and power quality to customers in the mid-west area.

4.3. Preferred Network Option

Ergon Energy's preferred internal network option is to install a 33/11kV transformer, 66kV feeder bays, 11kV feeder bays and associated protection and control equipment at the adjacent Cape River East Substation and decommissioning the existing Cape River Substation.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $8.78 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The proposed project timeline has design commencing in 2020/2021 and construction completed by 2022/2023.

5 Market Benefit Assessment Methodology

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the National Electricity Market.

In order to measure the increase in net market benefit, Ergon Energy has analysed the classes of market benefits required to be considered by the RIT-D.

5.1. Classes of Market Benefits Considered and Quantified

The following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding

5.1.1. Changes in Involuntary Load Shedding

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Ergon Energy has calculated the impact of changes in involuntary load shedding caused by outages at Cape River Substation, by comparing the expected unserved energy under the base case (where no action is undertaken by Ergon Energy) with credible options in place.

Probability weighted values of expected unserved energy have been calculated based on the probability of the failure, the energy at risk and the estimated restoration time. The derived values of expected unserved energy have been converted to a dollar figure, which reflects the customer financial consequence of the unserved energy. Ergon Energy has applied a location specific Value of Customer Reliability (VCR) of $39,306/MWh for the CARI 66kV load and $36,666/MWh for the CARI 11kV load, which have been derived from the 2014[2] AEMO VCR estimates.

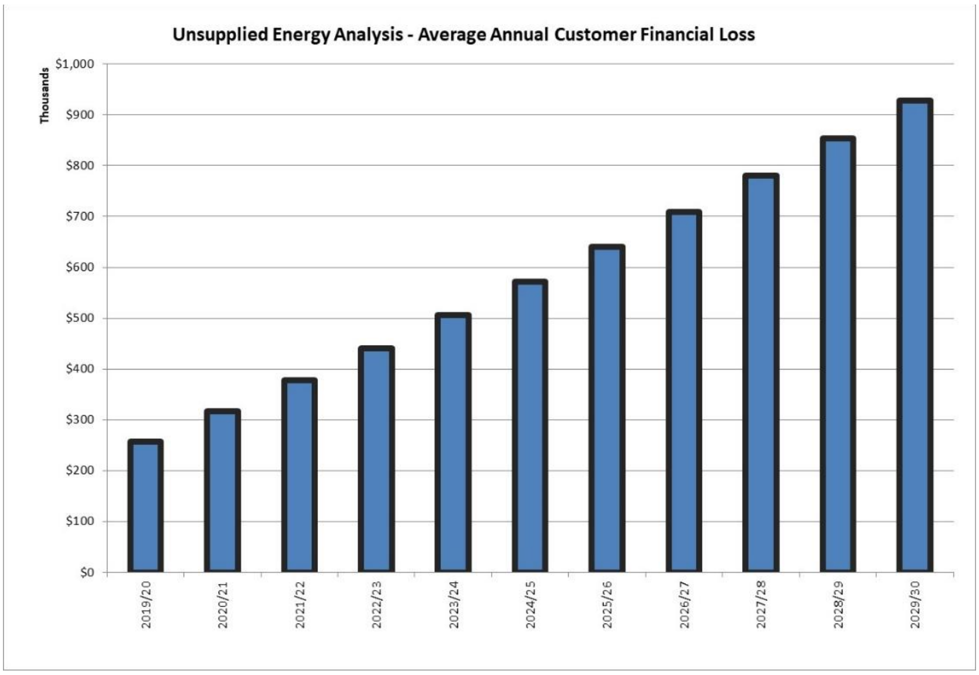

Figure 20 Assumed Average Annual Customer Financial Loss if no credible option is commissioned

The plot above shows the assumed average annual customer financial loss due to outages at Cape River Substation if no credible option is commissioned. The increase in financial loss over the 10-year period is based purely on the increase in probability of failure of existing assets and the

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[2] The AEMO VCR methodology has been used for this RIT-D as the RIT-D for this investment commenced prior to the publication of the AER VCR methodology https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/decision.

CPI adjustments to VCR. The assessment has assumed minimal growth in maximum demand and energy over the 10-year period and minimal change in restoration times.

The probability of substation asset failure has been assumed to be small enough to be considered negligible with the proposed credible network option in place.

Based on these assumptions, the reduction in expected unserved energy due to outages at Cape River Substation that the credible option is expected to deliver would be as presented in Figure 20 and has been included as a material market benefit.

5.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties
- Changes in timing of expenditure
- Changes in load transfer capability
- Changes in network losses
- Option value

5.2.1. Changes in Voluntary Load Curtailment

Because none of the credible options include any voluntary load curtailment, and because there are no customers on voluntary load curtailment agreements in the Cape River area at present, any market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.2. Changes in Costs to Other Parties

Ergon Energy does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

5.2.3. Changes in Timing of Expenditure

None of the credible options included in this RIT-D assessment is expected to affect the timing of other distribution investments for unrelated identified needs.

5.2.4. Changes in Load Transfer Capability

None of the credible options included in this RIT-D assessment are expected to affect load transfer capability between substations in the Mid-West area as the transfer capability is predominantly limited by the 66kV feeders. The proposed network option will improve plant rating capacity at the substation however the market benefits from this are not considered to be material due to the feeder limitations.

5.2.5. Changes in Network Losses

Ergon Energy does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in network losses.

5.2.6. Option Value

The AER's view is 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[3].

Ergon Energy does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

6 Detailed Economic Assessment

6.1. Net Present Value (NPV) Results

Net Present Values of the credible options are presented in Table 2 below. The NPV analysis demonstrates that Option A has the lowest Net Present Cost.

Note that the figures in the table below are the discounted present values evaluated over a 20-year period. These direct costs are preliminary estimates which are subject to change as costs are refined, and do not include any interest, risk, contingencies or overheads, but does include residual life values at the end of the 20-year period.

$ Millions	Option A	Option B
Capex	(4.03)	(2.99)
Opex	0.00	(1.01)
Direct Benefits	0.00	0.00
Commercial NPV	**(4.03)**	**(3.99)**
Ranking	*2*	*1*
Indirect/Risk	8.43	6.74
Commercial + Risk	**4.40**	**2.75**
Ranking	*1*	*2*

Table 2 – Net Present Value Analysis

The difference between operating and maintenance costs for the two options has been included in the NPV analysis. The operating and maintenance costs would be higher for Option B as there are two substations requiring ongoing maintenance.

[3] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A6. Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

The market benefits would be slightly different for the two options as some of the older assets in the CARI site will be retained for Option B resulting in a higher probability of asset failure compared to Option A.

Note: The above NPV analysis does not include the monetised values of all the network risks as well as the quantified values of all the market benefits that are not significant enough to make a difference in the preferred option.

7 Conclusion

The Final Project Assessment Report (FPAR) represents the final stage of the consultation process in relation to the application of the RIT-D.

Ergon Energy intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

7.1. Preferred Option

Ergon Energy's preferred network option is option A - to install a 33/11kV transformer, 66kV feeder bays, 11kV feeder bays and associated protection and control equipment at the adjacent Cape River East Substation and decommissioning the existing Cape River Substation. The details of option A are set out in section 4.1.1 of this report.

The estimated capital cost of this option inclusive of interest, risk, contingencies and overheads is $8.78 million. Annual operating and maintenance costs are anticipated to be 0.5% of the capital cost. The proposed project timeline has design commencing in 2020/2021 and construction completed by 2022/2023.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

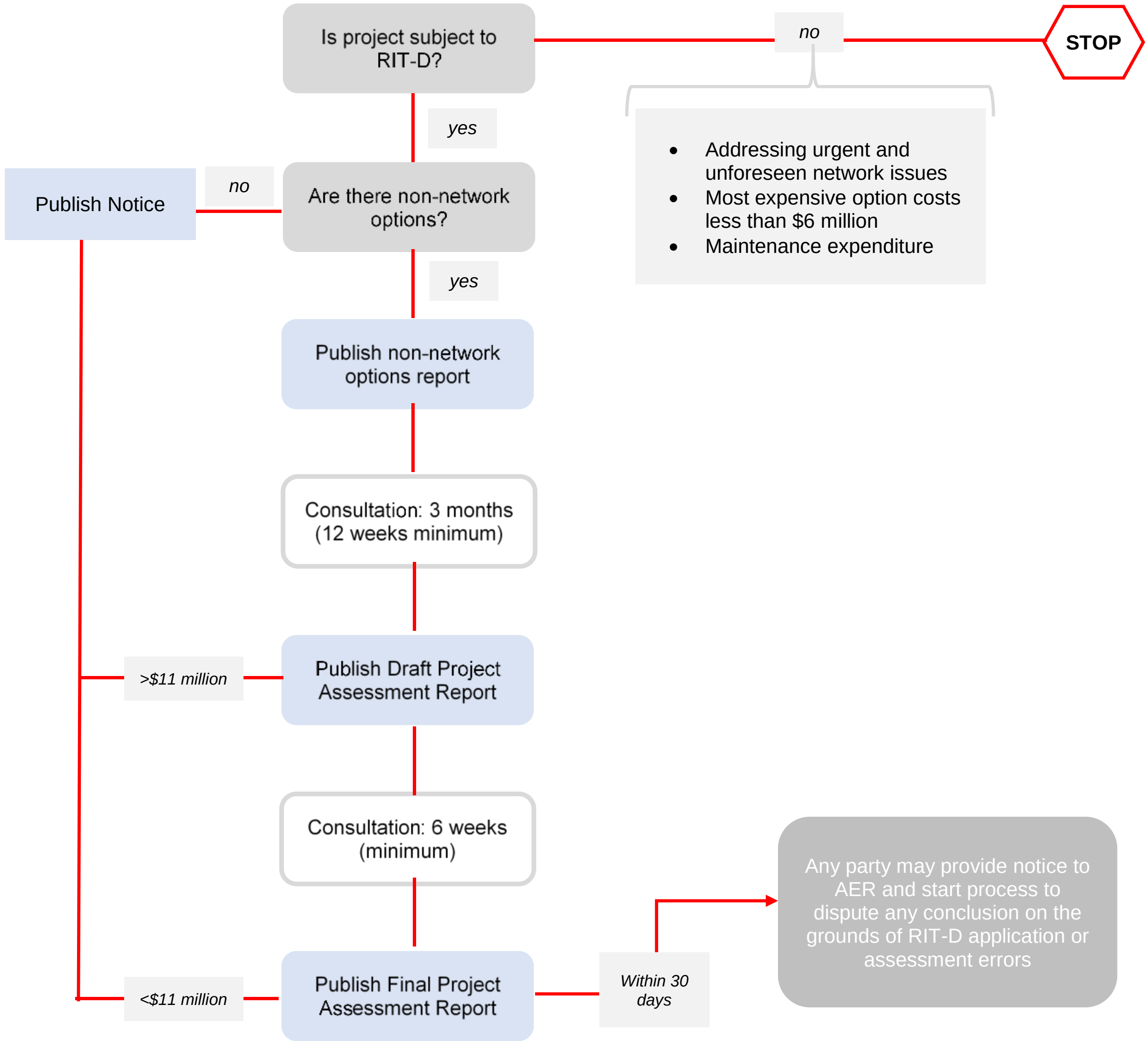
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8 Compliance Statement

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	N/A
(4) a description of each credible option assessed	4
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	5.1
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5.1
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.1
(10) the identification of the proposed preferred option	7.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	7
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.3

Appendix A – The RIT-D Process



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.