Regulatory Investment Test for Distribution (RIT-D)

Brunswick Zone Substation (C)

Non-network Options Report

1 March 2018

Table of Contents

1 Summary

This Non-network Options Report has been prepared by CitiPower Pty Ltd (**CitiPower**) in accordance with the requirements of clause 5.17.4(b) to (h) of the National Electricity Rules ("the **Rules**").

This report represents the first stage of the consultation process in relation to the application of the Regulatory Investment Test for Distribution (**RIT-D**) on potential credible options to address the identified need triggered by the planned retirement of 80 year old assets at Brunswick zone substation (**C**), which are in poor condition.

The need for investment and the possible options to address the identified need at C were foreshadowed in CitiPower's 2017 Distribution Annual Planning Report (**DAPR**).

A non-network option may address all or part of the identified need and as such CitiPower is seeking proposals from non-network providers.

1.1 The need for investment

Substation C was commissioned in 1938 as a 22kV/6.6kV substation and supplies approximately 5,200 customers in the Brunswick area.

Load is not forecast to exceed the station N-1 rating of 17 MVA in the next 10 years and there is no load at risk at C today. However, C has multiple assets including transformers, circuit breakers and auxiliary equipment at the end of their service life and the substation as a whole is supplied by old paper lead cables which are difficult to repair should a fault occur. These assets will present an increased operational and safety risk if they continue in service into the future.

As there is limited load transfer capability between C and the nearby Fitzroy (**F**), West Brunswick (**WB**) and Brunswick (**BK**) zone substations, there is a risk that should a major outage occur at C, customers will be left without electricity for a sustained period as we will be unable to restore supply to all customers until repairs are made. Moreover, our analysis indicates that in order to efficiently manage the risks to safety, and reliability and security of supply associated with the deterioration of the assets at C, this plant should be retired by 2021. In the absence of action to reduce load and/or replace the functional capability currently provided by these life-expired assets, it will not be possible to continue to supply the 5,200 customers from C once the life-expired assets are retired.

1.2 Possible solutions to address the identified need

The possible network solutions to address the identified need are:

- decommission C in 2021, install a third 66kV/11kV/6.6kV transformer at WB and transfer all load from C to WB prior to the 2021/22 summer;
- decommission C in 2021, install a third 66kV/11kV transformer at WB, transfer all load from C to WB and convert both C and WB supply areas to 11kV prior to the 2021/22 summer; and
- decommission existing assets at C and install two 66kV cables from the WMTS-Northcote sub-transmission line, and install two new transformers and associated plant at C for commissioning prior to the 2021/22 summer.

CitiPower considers that non-network options may assist in addressing some or all of the identified need. As an example, these options could include one, or a combination, of local generation or demand management.

CitiPower seeks proposals from non-network providers on any potential credible options to address the identified need.

1.3 Outline of this Non-network options report

This report has been prepared to facilitate proposals from stakeholders, including non-network providers, on possible options to address the identified need.

This report:

- sets out the background to the identified need;
- identifies the load at risk under a number of different scenarios;
- identifies a number of possible network and non-network solutions that may address the identified need;
- sets out the range of assumptions used in the calculations;
- outlines the process for making submissions.

Submissions to this report are sought by close of business at 17:00 on **29 May 2018**.

2 Background

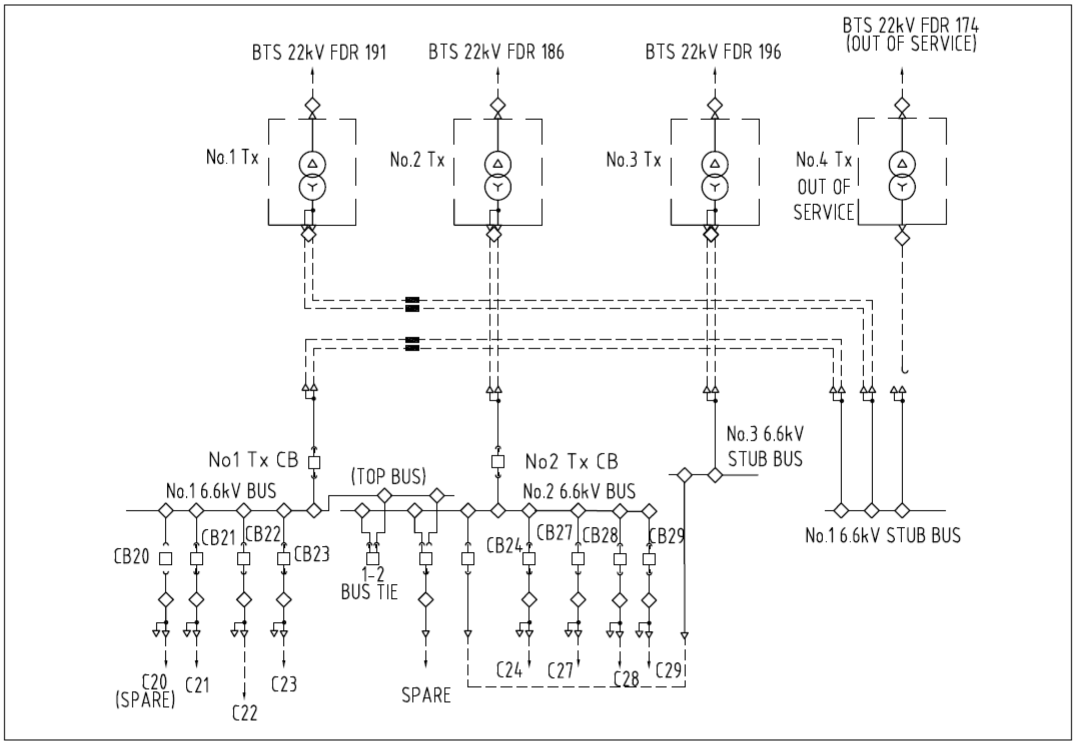
2.1 Zone substation C configuration

Substation C was commissioned in 1938 as a 22kV/6.6kV station with two 7.5MVA (name plate rating) transformers supplied via underground 22kV sub-transmission cables from Brunswick Terminal Station (**BTS**). Two additional 7.5MVA (name plate rating) transformers were installed in 1940 and 1942. One of the transformers has since been retired due to poor condition and as such the station N rating is based on three transformers.

There is no 22kV switching or 22kV bus tie meaning that the 22kV cables from BTS are directly connected to each of the transformers.

The transformers do not have on load tap changers and the secondary sides are connected to two 6.6kV busses supplying eight feeders. Figure 2.1 below shows a single line diagram of the current arrangements at substation C.

Figure 2.1: C single line diagram



2.2 Location

C is located on the south side of Brunswick Road west of the corner of Lygon Street, Brunswick and supplies electricity to 5,200 customers including 4,769 domestic, 385 commercial and 46 industrial customers in the Brunswick area. Figures 2.2 and 2.3 show the building location and the area supplied respectively.

Figure 2.2: Building location of C

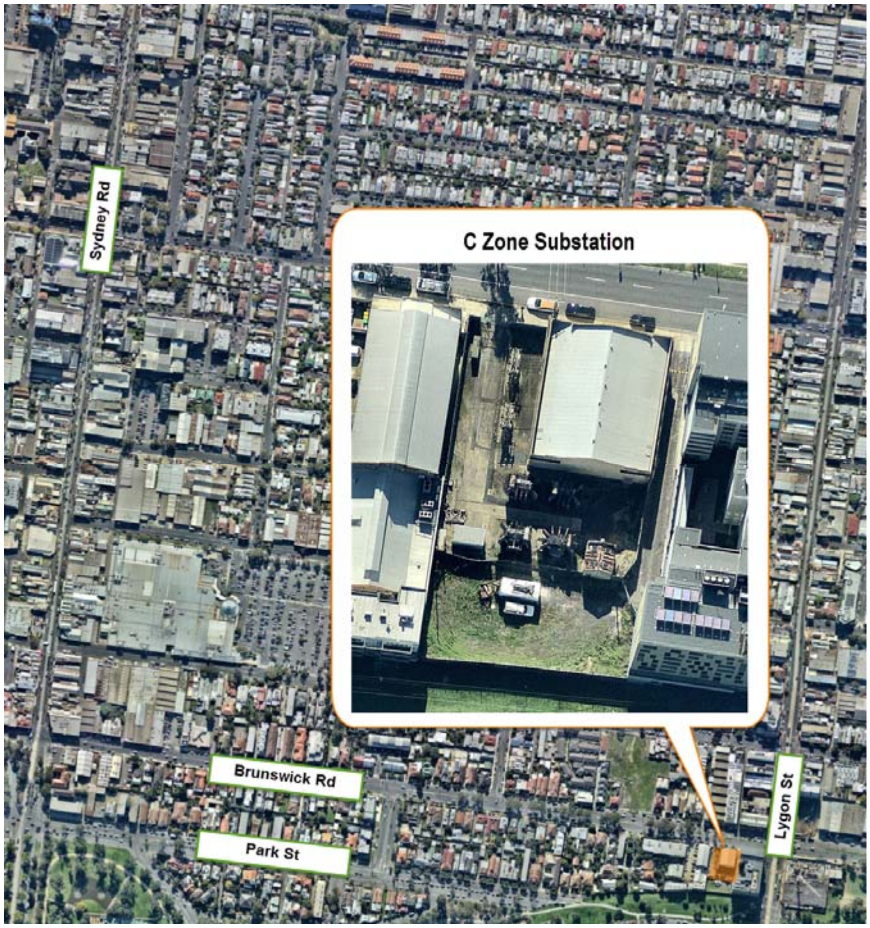
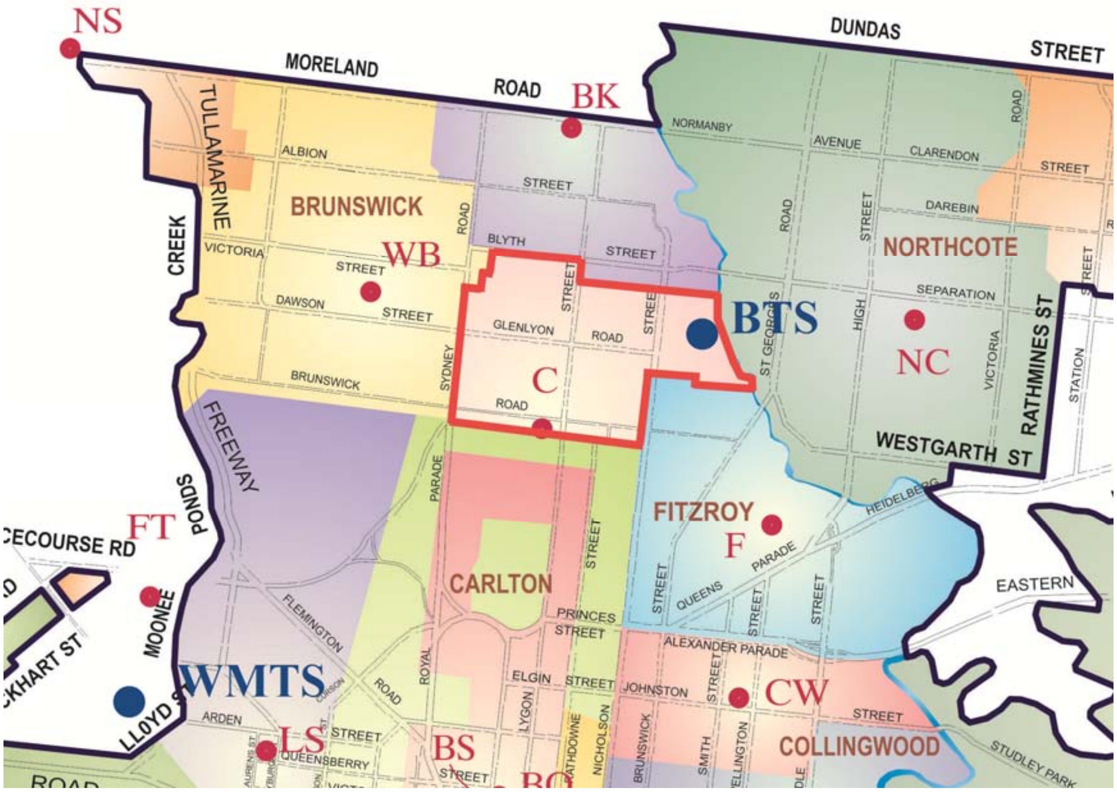


Figure 2.3: Geographical area supplied by C



2.3 Asset condition and risk

Assets at C are aged and in poor condition. The following sections provide further information on the operational and safety risks to personnel.

CitiPower applies the Condition Based Risk Management (CBRM[1]) methodology to certain plant-based asset classes, namely transformers and HV circuit breakers. The CBRM model is an asset risk assessment algorithm that takes into account a range

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1 The CBRM model takes into account a range of inputs including:

- condition assessment data, such as transformer oil condition;
- environmental factors, such as whether the assets are located indoors or outdoors, or coastal areas; and
- operating factors, such as the load utilisation, frequency of use and load profiles that the asset is supplying.

These factors are combined to produce a Health Index for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The Health Index provides a means of comparing similar assets in terms of their calculated probability of failure.

CitiPower closely monitors assets with a Health Index in the range 5 to 7 to determine options for intervention, including replacement or retirement, in the context of energy at risk. Interventions are evaluated and planned when asset Health Index exceeds 5.5 and intervention is prioritised when asset health index exceeds 7.

A Health Index profile gives an immediate appreciation of the condition of all assets in a group and an understanding of the future condition of the assets.

As part of the CBRM process, the consequence of failure of the asset is also calculated. This assesses the consequence to customers due to loss of supply. The loss of a large amount of load (in MW) to a large industrial customer or to a large number of residential customers will indicate a high consequence of failure. The consequence of failure consists of four elements:

- network performance;
- safety;
- financial;
- environment.

The risk to CitiPower is calculated by combining the probability of failure of the asset and the consequence of failure of the asset. CBRM is used to calculate how the risk will change in future years and to determine the optimum replacement time of an asset.

of inputs on the health of an asset. These factors are combined to produce a Health Index (HI) for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The risk increases more rapidly as the HI exceeds 7. The optimum intervention (either retirement or replacement) timing of an asset is determined by matching the highest risk reduction to the discounted intervention cost. Our latest CBRM analysis indicates that the optimum year to retire the deteriorating assets at C is 2021. The need for asset retirement in 2021 is further justified below, with reference to the increasing difficulty of reinstating the assets back into service following a defect.

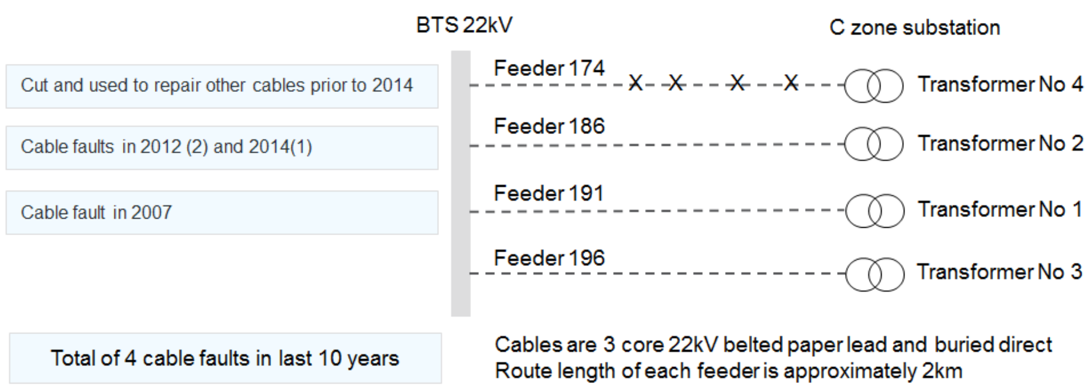
2.3.1 22kV Sub-transmission cables

The 22kV cables supplying C from BTS are of the belted paper lead type construction and date back to the late 1930s (80 years old).

The cables have experienced failures in recent years as shown in Figure 2.4, with some occurring in cable sections rather than joints which indicates the cable itself is close to end of life. Ageing and embrittlement of the lead sheath is a significant factor in the determination of end of life for this type of cable construction. The original fourth cable (which has been out of service for many years) has been used to cross joint around a number of failures in the other three cables.

The cables are direct buried (i.e. not in conduits) and are not able to be replaced in situ.

Figure 2.4: Summary of BTS-C 22kV sub-transmission cable failures in the last 10 years



2.3.2 Transformers and HV switchgear

The CBRM analysis has determined that all three transformers currently have a HI of 7.0 (rising to 8.00 in 2021), with the HV switchgear currently having a HI of 6.05 (rising to 6.27 in 2021).

In order to efficiently manage the risks to safety, and reliability and security of supply associated with the deterioration of the transformers and HV switchgear at C, this plant should be retired by 2021. In the absence of action to reduce load and/or replace the functional capability currently provided by these aging assets, it would not be possible to continue to supply the 5,200 customers from C.

Other considerations that are relevant to the timing of retirement of the assets at C include:

- one of the three transformers currently has an intermittent internal fault, posing a safety risk to personnel and other assets in the station. This fault is currently being monitored through additional inspections and condition assessments;
- there are no firewalls separating the transformers from each other or from the building that houses other equipment such as 6.6kV switchgear and protection equipment. This means that a catastrophic failure of any one transformer will result in damage to other transformers, the building and other assets in the substation;
- there is no oil containment bund for the transformers. This means that any catastrophic fault in the transformers is likely to result in uncontrolled oil spillage;
- due to the age of the HV circuit breakers, operational performance has declined. Slow operation of a circuit breaker during fault clearance may result in a full bus outage and loss of supply to half of the customers supplied from substation;
- the HV circuit breakers do not have motorised spring rewind. This means that an operator must attend the station to restore supply after any operation of the switchgear to clear a fault, delaying the restoration of supply to customers. Further it means that modern measures to enhance reliability such as auto reclose cannot be utilised;
- the HV switchboard is not arc fault contained or vented, therefore failure of the switchboard or any circuit breaker due to an internal fault poses a safety risk to personnel and other assets in the station;
- any catastrophic failure of a transformer or circuit breaker may result in a full station outage;
- spare parts are no longer available for aged major plant components. Any failure of a critical component requires reengineering of the part and further delays restoration of the asset into service.

2.3.3 Auxiliary equipment

The site has a significant number of aged mechanical protection relays and secondary equipment which is both limited in functionally and creates issues interfacing with the more modern relays protecting supply from BTS. This raises the risk of protection mal-operation leading to an increased frequency of transformer outages at C. This has already occurred in the past on Feeder 196 (as shown in

Figure 2.4) which was out of service for 17 months from June 2016 to November 2017 due to a protection fault. The delay in restoration time was due to a lack of spares and difficulty in interfacing with BTS.

2.4 Historical and forecast demand

Traditionally C is a winter peaking zone substation, however in recent years the station has experienced its peak in summer, with residential customers being the main contributors to the demand. The historical and forecast demand for summer and winter is shown in Figures 2.5 and 2.6 respectively. Both figures show the planned retirement of C in 2021, and assume that no action is taken to replace its capacity or reduce demand following C’s removal from service.

Figure 2.5: C summer actual and forecast demand with assets retired in 2021

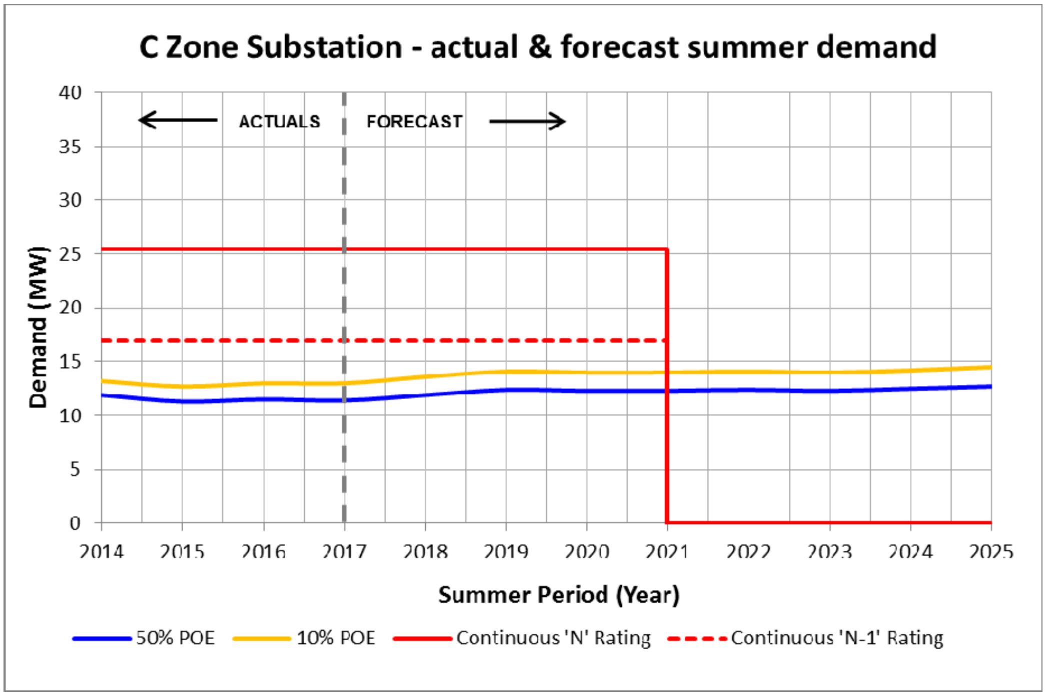
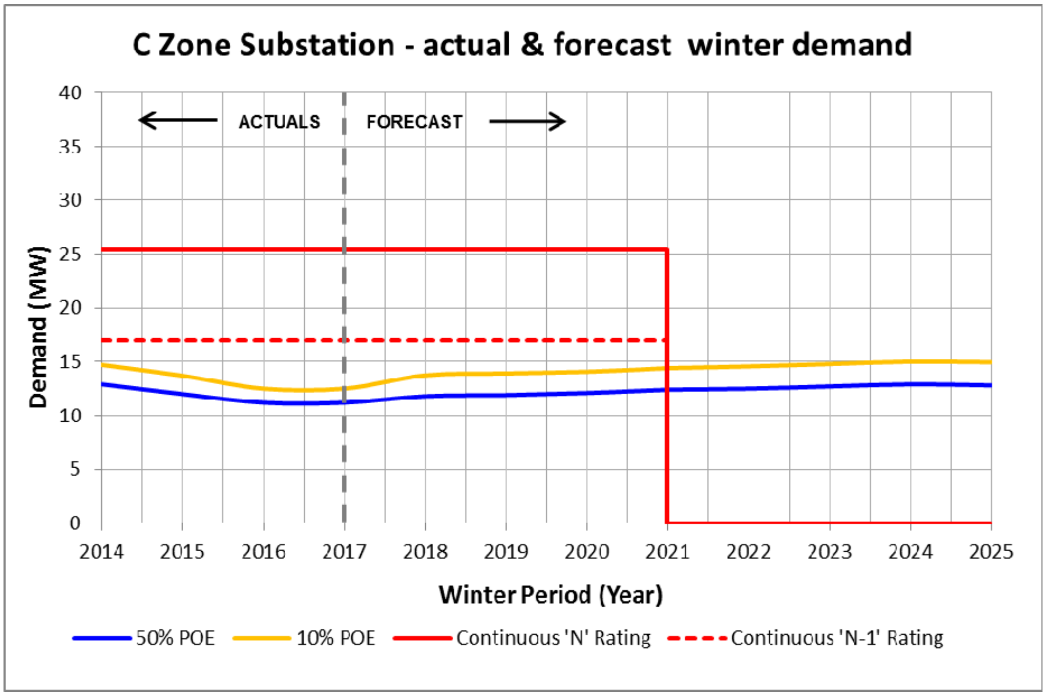


Figure 2.6: C winter actual and forecast demand with assets retired in 2021



CitiPower estimates that in 2021 the forecast peak demand at C will be 12.8MVA for summer and 13.2MVA for winter.

2.5 Load transfer capacity to adjacent zone substations

The load transfer capability between C and nearby F, WB and BK zone substations is limited. During peak demand an estimated maximum transfer capacity of 4.0 MVA is available via 6.6kV links to these adjacent zone substations as an operational response to partially mitigate the impact of an outage at C.

3 Key issues to be addressed

As shown in section 2.4, load at C is not forecast to exceed the station N-1 rating of 17 MVA in the next 10 years and there is no load at risk at the zone substation today. However, as explained in section 2.3, C has multiple assets including transformers, circuit breakers and auxiliary equipment at the end of their service life. These assets pose an unacceptable risk to safety, reliability and security of supply, and as such are scheduled to be retired in 2021.

Table 3.2 sets out the forecasts over the next 10 years of load at risk, hours at risk and expected unserved energy for customers currently supplied from C, assuming it is removed from the network in 2021 as planned and no action is taken to replace its capability. The load forecasts used assume the 50% and 10% probability of exceedance (PoE) demand for the relevant summer and winter.

Under normal circumstances the expected unserved energy value would present the value of the total energy (in MWh) that would not be supplied in the event of a transformer failure, multiplied by the probability of a transformer failure. In this case, after C is removed from the network in 2021, the expected unserved energy is expressed as the value of all energy at the substation. This is calculated by multiplying the forecast of the energy quantity that would have been supplied from C by the VCR (value of customer reliability)[2] values for the customer segments supplied.

The assumptions used in this calculation are listed in Table 3.1.

Table 3.1: Assumptions used to evaluate load at risk, expected unserved energy and hours at risk

Variable or parameter	Assumption applied
Growth in forecast demand	1.25% annual growth in load forecast.
Weighting of demand forecasts to estimate expected unserved energy	Total unserved energy estimated by taking a 70% weighting of expected unserved energy at the 50th percentile forecast and 30% weighting of expected unserved energy at the 10th percentile forecast.
Value of unserved energy (VCR)	$37,743 per MWh

[2] The VCR used in this analysis is based on the VCR published in the 2017 Transmission Connection Planning Report, which is, in turn based on Victorian VCR data published by AEMO for network planning purposes.

Table 3.2: Load at risk, hours at risk and expected unserved energy

Zone substation C	2018	2019	2020	2021[3]	2022	2023	2024	2025	2026	2027
50% PoE summer load at risk (MVA)	0	0	0	12.8	12.9	12.8	13.0	13.3	13.3	13.5
50% PoE summer load at risk (%)	0	0	0	100	100	100	100	100	100	100
50% PoE winter load at risk (MVA)	0	0	0	13.2	13.3	13.4	13.7	13.6	13.8	14.0
50% PoE winter load at risk (%)	0	0	0	100	100	100	100	100	100	100
Total energy at risk at 50% PoE (MWh)	0	0	0	47285	47688	47920	48623	48975	49464	50085
Total hours at risk at 50% PoE (Hrs)	0	0	0	8760	8760	8760	8760	8760	8760	8760
10% PoE summer load at risk (MVA)	0	0	0	14.4	14.5	14.4	14.6	14.9	14.9	15.2
10% PoE summer load at risk (%)	0	0	0	100	100	100	100	100	100	100
10% PoE winter load at risk (MVA)	0	0	0	14.4	14.6	14.8	15.0	15.0	15.2	15.4
10% PoE winter load at risk (%)	0	0	0	100	100	100	100	100	100	100
Total energy at risk at 10% PoE (MWh)	0	0	0	55602	56074	56365	57193	57588	58176	58900
Total hours at risk at 10% PoE (Hrs)	0	0	0	8760	8760	8760	8760	8760	8760	8760
Expected unserved energy value using AEMO weighting of 0.7 X 50% PoE + 0.3 X 10% PoE at VCR value($Million)	0	0	0	1878.85	1894.83	1904.27	1932.20	1945.98	1965.57	1990.16

The following issues exist at C:

- Limited load transfer capability exists between C and the neighbouring zone substations at WB, BK and F. The lack of transfer capability and support for C is a risk to the security of supply to customers.

- As shown in Table 3.2, using the 50% PoE load forecast, with retirement of transformers and HV switchgear at C, customers face an expected supply interruption cost of $1878.85 million in 2021.

[3] Transformers and HV switchgear retired at C in 2021

4 Potential credible options

This section sets out the network and non-network options that may address the identified need.

In addition, this section sets out the network options which were not considered to be technically or economically feasible and able to be implemented in sufficient time.

4.1 Credible network options

Table 4.1 provides a description of the network options that have been identified as feasible or potentially feasible.

Table 4.1: Potential credible network options

Option	Description
Base case	**Do nothing** This option provides the base case against which the net market benefits of all other options are evaluated.
1	**Install a third transformer (20/30 MVA), second 66kV circuit breaker and a third 6.6kV/11 kV bus at WB.** **Install six additional 6.6 kV feeders at WB and augment three existing feeders to offload C by 13.2 MVA.** **Install a 66kV 4 ohm reactor on the 66kV sub-transmission line from West Melbourne Terminal Station (WMTS) to WB to comply with the fault level requirements on the 6.6kV secondary side when operating two transformers in parallel.** **To be commissioned prior to the 2021/22 summer.** **Decommission C in 2021.** This option aligns with CitiPower’s strategy to replace the 22kV sub-transmission network with 66kV. The estimated total direct capital cost of this option is $18.7 million (undiscounted).
2	**Install a third transformer (20/30 MVA), second 66kV circuit breaker and replace the existing 6.6kV switchboard with a new 11kV switchboard at WB.** **Convert the C and WB 6.6kV distribution network to 11kV.** **Install two additional 11kV feeders at WB and augment three existing feeders to offload C by 13.2MVA.** **To be commissioned prior to the 2021/22 summer.** **Decommission C in 2021.** This option is similar in scope to Option 1, but involves converting existing 6.6kV distribution feeders to 11kV. This project aligns with CitiPower’s strategy to replace the 22kV sub-transmission with 66kV as well as upgrading the associated 6.6kV distribution network to 11kV. The estimated total direct capital cost of this option is $30.5 million (undiscounted).

Option	Description
3	**Install two 66kV cables from WMTS-Northcote (NC) sub-transmission line, 66kV bus structure, 66kV circuit breaker, two transformers (20/27MVA) and 6.6kV switchboard at C. To be commissioned prior to the 2021/22 summer.** **Decommission existing transformers and switchgear at C in 2021.** This option aligns with CitiPower's strategy to replace the 22kV sub-transmission network with 66kV. Also, this project will house the new 6.6kV switchgear and auxiliary equipment in the existing 80 year old building. The estimated total direct capital and operating costs of this option is $20.4 million (undiscounted).

4.2 Selection of preferred network option

In selecting the preferred network option, the objective is to maximise net economic benefit[4]. Each of the feasible network options deliver the same level of benefits, in terms of continuing to reliably supply load to the customers who are presently supplied from C. Therefore, the preferred option can be identified as the one that minimises total present value costs.

The table below shows the discounted or total present value costs of the three network options.

Table 4.2: Present value costs of credible network options ($ million in 2018)

	Option 1	Option 2	Option 3
Capital expenditure	17.46	28.55	19.07
Operating expenditure	0.13	0.31	0.20
Total cost	17.59	28.86	19.27

The preferred option is Option 1 because it minimises total present value costs. As noted above, this is consistent with maximising net economic benefit.

4.3 Non-network options

Table 4.3 provides a description of the non-network options that have been identified as feasible or potentially feasible.

4 Clause 5.17.1(b) of the National Electricity Rules.

Table 4.3: Potentially feasible non-network options

Option	Description
Base case	**Do nothing** This option provides the base case against which the net market benefits of all other options are evaluated.
4	**Interconnect 6.6kV network to WB, BK and F, and utilise generation on the CitiPower Network to defer option 1** This option involves installation of local generation to defer Option 1 by up to five years.
5	**Interconnect 6.6kV network to WB, BK and F, and utilise demand management on the CitiPower Network to defer option 1** This option involves demand management by voluntary load reduction to defer Option 1 by at least one year.
6	**Interconnect 6.6kV network to WB, BK and F, and utilise a combination of demand management and generation on the CitiPower Network to defer option 1** This option involves using a mix of demand management and local generation to defer option 1 by at least one year.

The remainder of this section describes the technical characteristics required of a non-network support option to address the identified need. A potentially credible non-network option must satisfy the timing, operational and technical requirements as detailed below.

4.3.1 Size and location

Table 4.4 outlines the forecast amount of generation or demand management required at C to be supplied by a potentially credible non-network option under a 50% PoE load forecast. The table also outlines the expected number of hours in each year that would likely be required to eliminate the load at risk at C.

Table 4.4: C demand offsets required from a non-network solution

Year	Summer Load at Risk(MVA)	Winter Load at Risk (MVA)	Hours at Risk	Expected unserved energy ($ Million)
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	12.8	13.2	8760	1878.85
2022	12.9	13.3	8760	1894.83
2023	12.8	13.4	8760	1904.27
2024	13.0	13.7	8760	1932.20
2025	13.3	13.6	8760	1945.98
2026	13.3	13.8	8760	1965.57
2027	13.5	14.0	8760	1990.16

4.3.2 Time of year

A credible non-network support option must, at a minimum, be capable of increasing network capacity or reducing network loading in the Brunswick supply area during the whole year.

4.3.3 Commissioning date

A credible non-network support option must be commissioned and capable of increasing network capacity or reducing network loading before summer 2021/22.

4.3.4 Load profile characteristics

Substation C's load profile on the day of the 2016/2017 summer maximum demand and 2017 winter maximum demand is illustrated in Figures 4.1 and 4.2 respectively.

Figure 4.1: Load profile at C for 2016/17 summer maximum demand

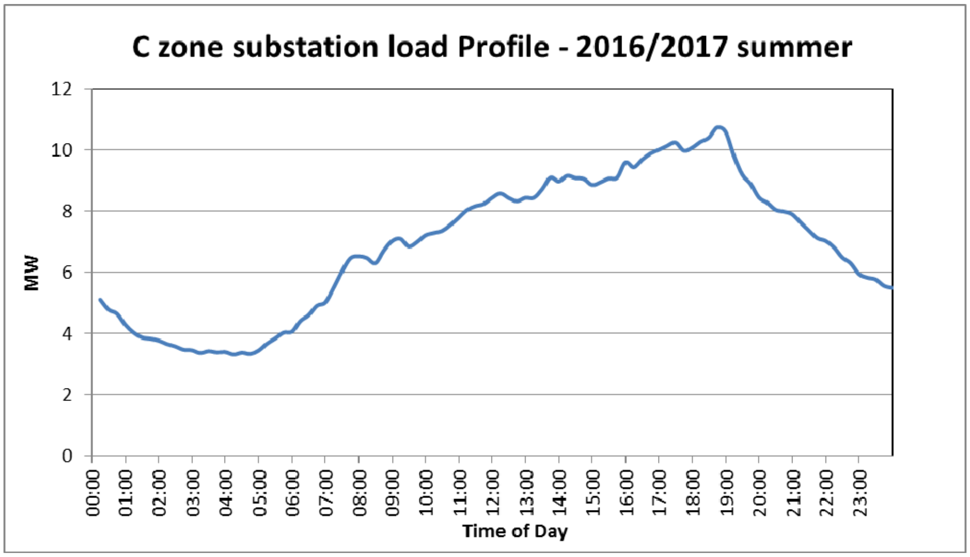
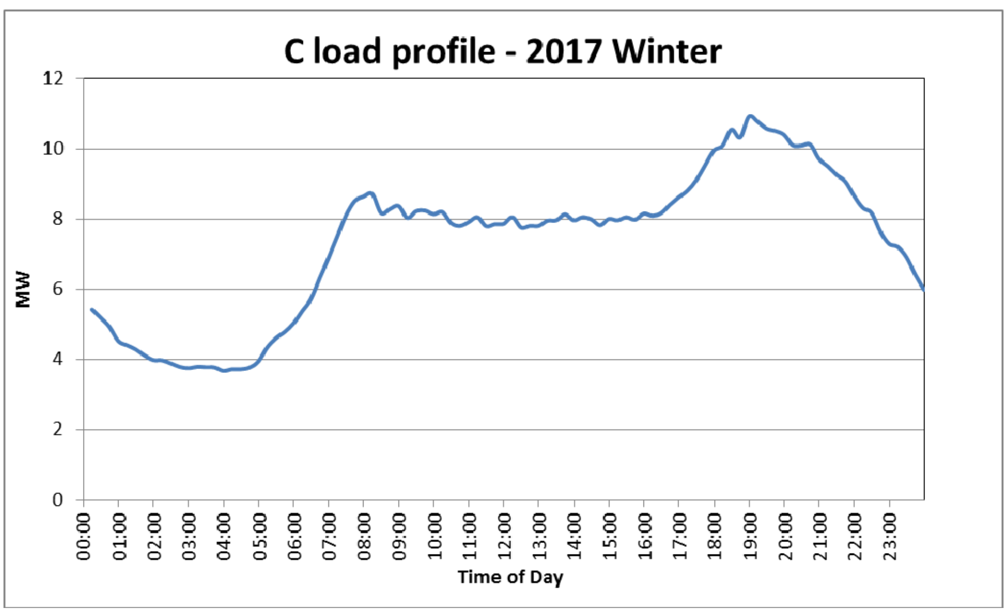


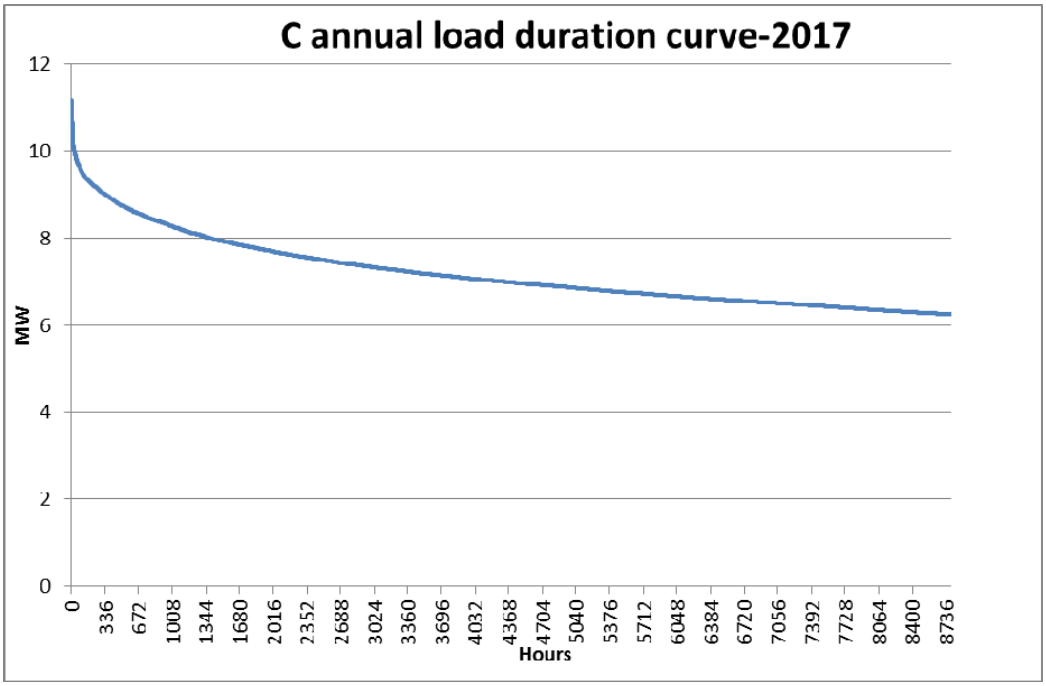
Figure 4.2: Load profile at C for 2017 winter maximum demand



In both summer and winter, the peak demand occurs in the evening, which is typical of a station that supplies predominately residential customers.

The annual load duration curve for 2017 is shown in the figure below.

Figure 4.3: Annual load duration curve at C for 2017



4.3.5 Reliability

Proposed non-network support options must be capable of reliably meeting the electricity demand under a range of conditions. If the non-network support option is a generator operating in parallel with CitiPower's network, the generator must comply with the requirements set out in CitiPower's 'Customer Guideline- High Voltage Distribution Connected Embedded Generation'. A link to these guidelines is provided below.

https://www.powercor.com.au/media/2150/customer-guidelines-hv-v2-final.pdf

4.3.6 Fault level contribution

The installation of an embedded generator may raise the fault level of the network to which it is connected. It is important to ascertain that the resulting fault levels are not raised above the existing acceptable rated fault levels for circuit breakers, conductors, any auxiliary plant and fittings including earth grid, Distribution Code or design limits. If required, system fault level studies will be carried out at the embedded generator proponent's cost.

As per the Victorian Electricity Distribution Code (VEDC) an embedded generator must design and operate its embedded generation unit so that it does not cause fault levels in the distribution system to exceed the levels specified in Table 4.5.

Table 4.5: VEDC fault level limits

Voltage level (kV)	System fault level (MVA)	Short circuit level (kA)
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50

The 6.6kV three phase fault levels at nearby F, WB and BK zone substations are shown in Table 4.6.

Table 4.6: 6.6kV three phase faults levels at zone substations nearby C

Zone Substation	System fault level (MVA)	Short circuit level (kA)
F	179	15.7
WB	140	12.2
BK	213	18.6

4.4 Other network options considered

Table 4.7 describes other network options considered by CitiPower but rejected due to either being technically or economically not feasible.

Table 4.7: Other network options considered

Option	Description
7	**Install 11kV feeders from WB to C, and BK to C to offload C by 13.2MVA.** **Replace one transformer at BK.** **Convert the C, WB and BK distribution network from 6.6kV to 11kV.** **Decommission C by 2021.** This option requires existing 6.6kV/11kV dual rated switchgear at WB and BK to operate at 11kV. Tests conducted by CitiPower of the HV switchboard at BK indicate that it is unsuitable to operate at 11kV and as such this option was not pursued any further.
8	**Establish a new zone substation. Purchase a new site in the Brunswick area, install 66kV sub-transmission lines, one 66kV circuit breaker, two transformers, 6.6kV distribution feeders and feeder ties to the distribution area served by C.** Acquisition of an appropriate site to house the new zone substation in the densely populated Brunswick area was considered unlikely. This option is also subject to construction difficulties and disruption to the community due to the amount of feeder works. For these reasons this option was not evaluated any further.

4.5 Indicative annualised cost of preferred network option

At a nominal discount rate of 6.11%, the annualised cost of Option 1 (WB zone substation 3rd transformer and new feeders to offload C) over 50 years is approximately $1.2 million (including operating expenditure).

Assuming that the non-network option delivers the same level of supply reliability as the preferred option, the annualised cost of the non-network option will need to be lower than the annualised cost of Option 1, the preferred network option.

5 Lodging a submission

This non-network options report provides information to proponents of non-network solutions (such as embedded generation or demand management) to address the identified need. CitiPower's aim is to develop the distribution network in a manner that maximises net economic benefit to customers. To this end, proponents of non-network solutions to the identified need described in this report are invited to lodge proposals with CitiPower.

5.1 Where to lodge submissions or direct queries

To assist in the assessment of non-network solutions, proponents are invited to lodge a detailed submission to CitiPower. Submissions will be published on the CitiPower website. If you do not want your submission to be made publicly available, please state this at the time of lodgement.

Submissions can be provided electronically to the email address provided below, or lodged by mail and sent to:

Shalini Chinta
Asset Strategy Engineer

CitiPower Australia Limited
Locked Bag 14090
Melbourne 8001.

Email: ritdenquiries@citipower.com.au

All enquiries relating to this non-network options report, or requests for information, should also be directed to the person named above.

CitiPower encourages any interested parties to contact us with any enquiries as early as possible to effectively develop proposals.

Interested parties are invited to provide submissions by close of business at 17:00 on **29 May 2018**.

5.2 Contents of a non-network proposal

Where respondents are intending to submit a non-network proposal, the submission is required to include:

- proponent name and contact details;
- overview of the objectives including the extent to which the proposal addresses the identified need;
- technical description, including but not limited to:
  - location;
  - size of the load reduction or additional supply;
  - electrical layout schematics;

  - network connection requirements, if needed;
  - contribution to power system security or reliability;
  - contribution to power system fault levels, load flows and stability studies (if applicable);
  - the operating profile;
  - reliability;
  - how each of these matters is consistent with the technical standards and statutory requirements (guidance on these is available from the CitiPower website);
- timing of delivery of solution and its estimated lifespan;
- proposed operational and contractual commitments, including financier commitments;
- planning application information, where required;
- salvage and removal costs; and
- potential risks associated with the proposal and comparison with the risks associated with the deferred augmentation, and any actions that can be taken to mitigate these risks. This should address the risk of not meeting the demand requirement and how any penalties for non-supply will be addressed.

CitiPower will review each non-network option and may seek further information from the non-network provider to better understand the design of the proposed solution and its implications on the network and other network users.

5.3 Assessment of responses

CitiPower will consider the extent to which the non-network solution addresses the identified need. The proposal must lead to a deferment of a network solution that would otherwise have to be undertaken to address the identified need.

Where the option does not fully meet the identified need, consideration may be given to a hybrid option which combines the non-network solution with a network solution.

The matters that CitiPower will take into account when assessing each non-network proposal are:

- size, type and location of:
  - load(s) that can be reduced, shifted, substituted or interrupted; or
  - generators that can be utilised if required;
  - the extent to which the proposal addresses the identified need;
- type of action or technology proposed to address the identified need;
- reliability of the proposed solution compared to the network solution;

- time required to implement the proposed solution, and any period of notice required before loads can be interrupted or generators started and whether this is appropriate to address the identified need;
- the length of time that the network augmentation is deferred;
- implications of the life-cycle of the asset including the predictability of the effectiveness of the possible option;
- quantification of material market benefits; and
- quantification of costs to implement, operate and maintain the option, including:
    - any cost savings that would accrue to the owners/ operators of the equipment;
    - costs of any contribution or assistance that CitiPower may be required to make in order to implement the option, such as network support payments;
    - costs of complying with laws, regulations and applicable administrative requirements; and
    - costs and complexity of any network augmentation works.

In addition, CitiPower may take into account any other information that is relevant to assisting in the investigation and evaluation of non-network options. This will include the possible implications of the non-network solution on other network users.