Addressing reliability requirements in the Kingsford load area

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

17 JUNE 2022

Addressing reliability requirements in the Kingsford load area

Notice on screening for non-network options – 17 June 2022

Title of Contents

DISCLAIMER 1

1 INTRODUCTION 2

2 ELECTRICITY DEMAND 3

- 2.1 Network configuration 3
- 2.2 Demand forecast 3
  - 2.2.1 Demand forecast – Clovelly 4
  - 2.2.2 Demand forecast – Kingsford 4
  - 2.2.3 Demand forecast – Maroubra 5
- 2.3 Pattern of use 6
  - 2.3.1 Pattern of use – Clovelly 6
  - 2.3.2 Pattern of use – Kingsford 9
  - 2.3.3 Pattern of use – Maroubra ZS 12
- 2.4 Customer characteristics 15

3 AGED ASSET ISSUES 17

4 PROPOSED PREFERRED NETWORK OPTION 18

5 ASSESSMENT OF NON-NETWORK SOLUTIONS 20

- 5.1 Required demand management characteristics 20
- 5.2 Available demand management funds 20
- 5.3 Demand management options considered 20
  - 5.3.1 Customer power factor correction 20
  - 5.3.2 Customer solar power systems 21
  - 5.3.3 Customer energy efficiency 21
  - 5.3.4 Demand response 21
  - 5.3.5 Large customer energy storage 21

6 CONCLUSION 22

Disclaimer

Ausgrid is registered as both a Distribution Network Service Provider and a Transmission Network Service Provider. This notice on screening for non-network options has been prepared and published by Ausgrid under clause 5.17 of the National Electricity Rules to notify Registered Participants and Interested Parties of the results of the regulatory investment test for distribution and should only be used for those purposes.

This document does not purport to contain all of the information that a prospective investor or participant or potential participant in the National Electricity Market, or any other person or interested parties may require. In preparing this document it is not possible nor is it intended for Ausgrid to have regard to the investment objectives, financial situation and particular needs of each person who reads or uses this document.

This document, and the information it contains, may change as new information becomes available or if circumstances change. Anyone proposing to rely on or use the information in this document should independently verify and check the accuracy, completeness, reliability and suitability of that information for their own purposes.

Accordingly, Ausgrid makes no representations or warranty as to the accuracy, reliability, completeness or suitability for particular purposes of the information in this document. Persons reading or utilising this document acknowledge that Ausgrid and their employees, agents and consultants shall have no liability (including liability to any person by reason of negligence or negligent misstatement) for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from, or for any omissions from, the information contained in this document, except insofar as liability arising under New South Wales and Commonwealth legislation.

1 Introduction

The underground 132kV electricity subtransmission cables (‘feeders’) commissioned in the 1960s and 1970s, are now reaching, or past, the end of their technical lives. In particular, the self-contained fluid filled (**SCFF**) feeders are now considered an obsolete and outdated technology. They are becoming less reliable and approaching the point at which their replacement maximises the net benefit for the community.

Ausgrid identified the need to replace 132kV Feeder 264 supplying the Kingsford load area and has identified a preferred network solution to mitigate the identified risks.

Capital expenditure for replacement projects are subject to the Regulatory Investment Test for Distribution (RIT-D). No exemptions listed in the NER clause 5.17.3(a) apply and therefore Ausgrid is required to apply the RIT-D to this project. Accordingly, Ausgrid has initiated this RIT-D to replace the 132kV Feeder 264 in order to identify a preferred option that would ensure Ausgrid is able to satisfy its reliability and performance standards in supplying the Kingsford load area.

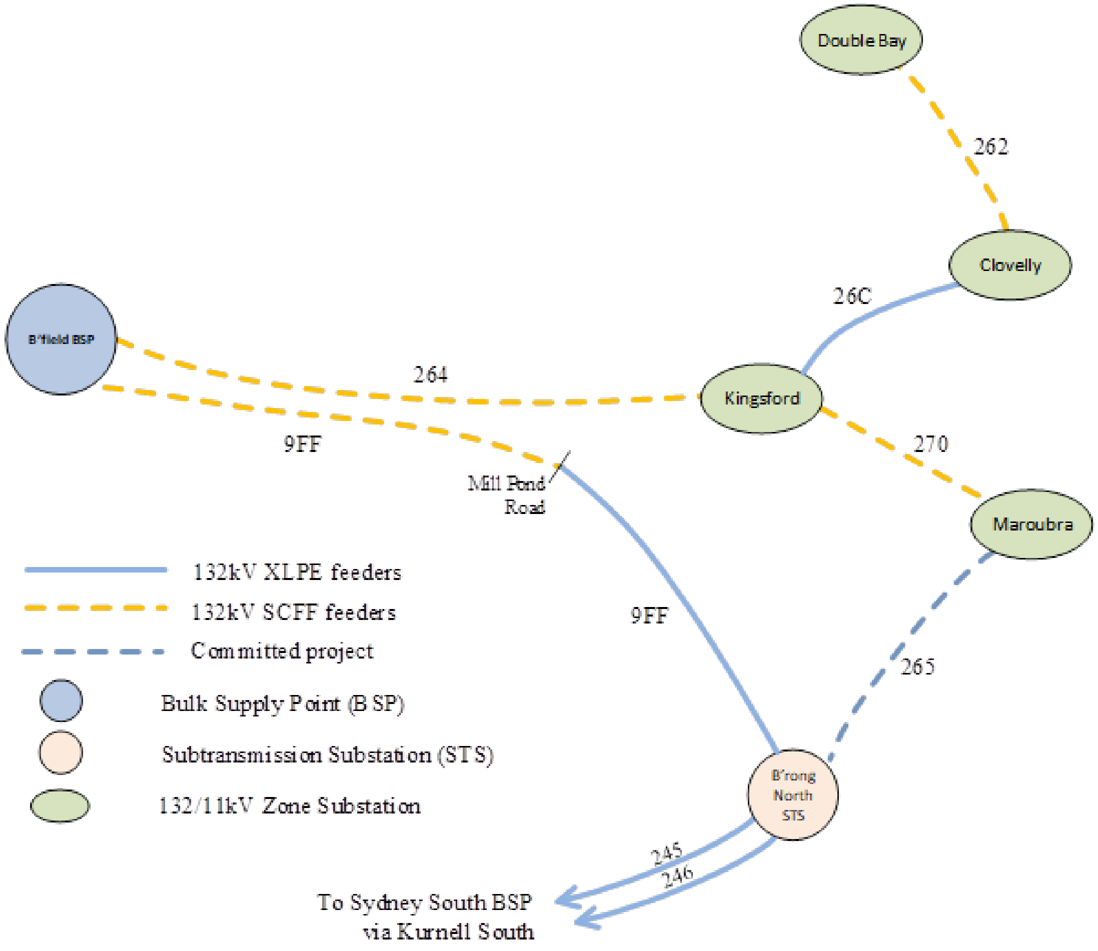
This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ausgrid’s determination that no non-network option is, or forms a significant part of, any potential credible option for this RIT-D. It sets out the reasons for Ausgrid’s determination, including the methodologies and assumptions used. A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR).

2 Electricity demand

2.1 Network configuration

Commissioned in 1977, Feeder 264 runs from Beaconsfield Bulk Supply Point (BSP) to Kingsford Zone Substation (ZS). Approximately 5.5km in length, this 132kV feeder forms part of a ring network that connects Beaconsfield BSP and Bunnerong Subtransmission Switching Station (STSS) via Kingsford and Maroubra ZSs and hence, provides reliable supply to zones in this ring network located in the Eastern Suburbs area. While the current network arrangement ensures a level of redundancy, any outage of this feeder at the same time as an outage on Feeders 265 and 262 (Double Bay ZS to Clovelly ZS) would result in the loss of supply to Clovelly, Kingsford and Maroubra ZS's, affecting approximately 60,000 customers in this area, including the University of New South Wales, the Prince of Wales Hospital, and the Sydney Light Rail.

Figure 1: 132kV network relevant to feeder 264



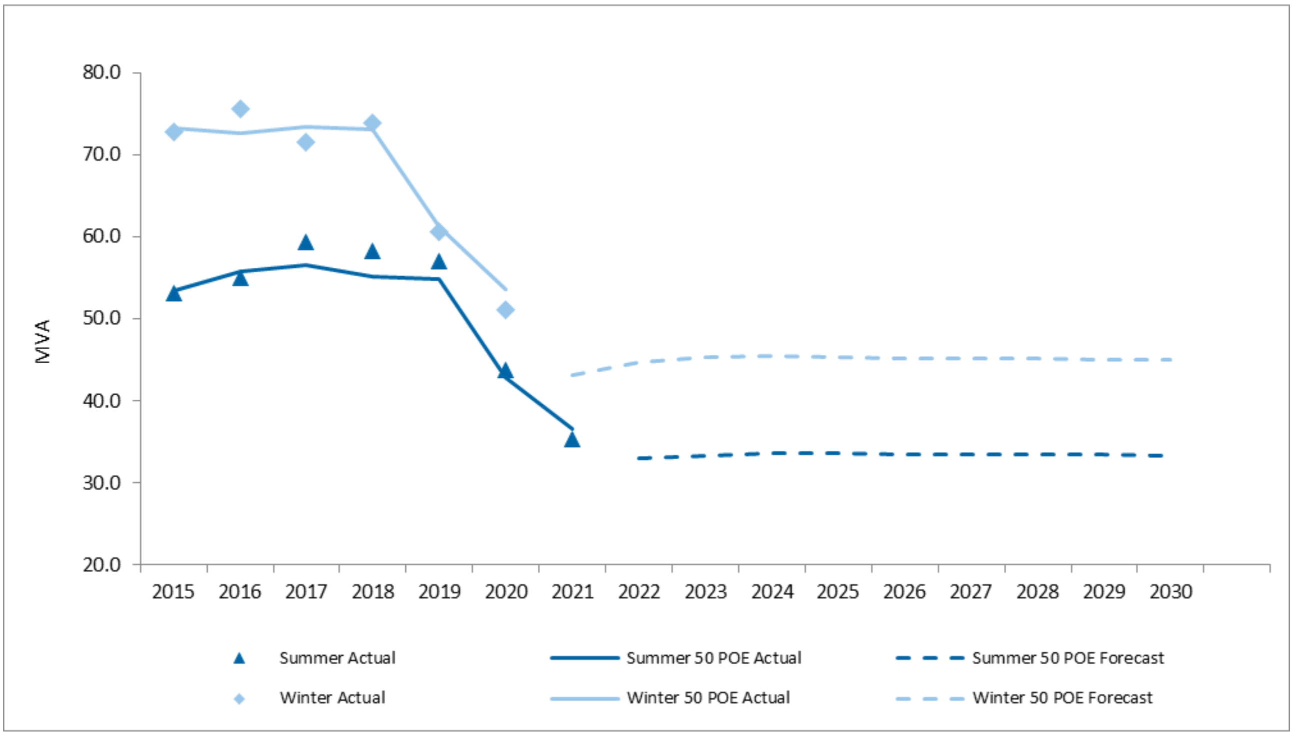
2.2 Demand forecast

While the identified need is associated with aged asset issues, a sufficiently large demand reduction may potentially defer the proposed preferred network solution. Due to the ring configuration of the network, the relevant areas where demand reductions could contribute towards a deferral are served from Clovelly, Kingsford and Maroubra zone substations. Figures 2, 3 and 4 below show the summer and winter maximum demand forecasts for Clovelly, Kingsford ZS and Maroubra ZS from Ausgrid's published 2021 forecast, which include the historical actual demand, the 50% probability of exceedance level (50 POE) weather corrected historical demand and the 50 POE forecast demand.

2.2.1 Demand forecast – Clovelly

Clovelly zone substation has a total capacity of 152.4 MVA and a firm capacity of 87.6 MVA in summer and 93 MVA in winter. In 2020/21, the maximum demand on the zone substation was 51 MVA which occurred at 7:15 pm AEST on 16 July 2020. The weather corrected demand at the 50 POE level was 53.6 MVA. The power factor at the time of summer maximum demand was 1. Maximum demand has typically occurred in winter in past years with time of peak ranging between 7:00pm and 7:30pm AEST. The downward step change in the first year of forecast is due to the impact of load transfers away from Clovelly zone substation.

Figure 2: Demand forecast at Clovelly zone substation

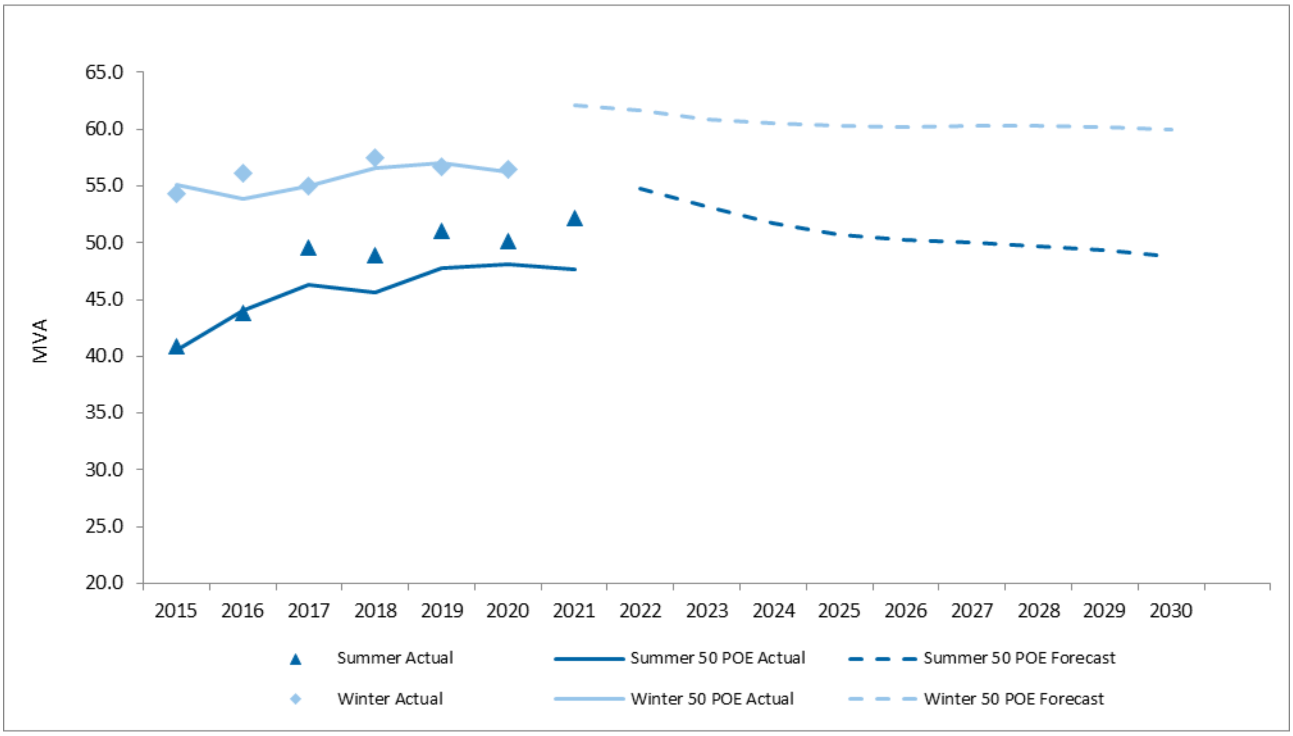


2.2.2 Demand forecast – Kingsford

Kingsford zone substation has a total capacity of 124.6 MVA and a firm capacity of 62.2 MVA in summer and 65 MVA in winter. In 2020/21, the maximum demand on the zone substation was 56.5 MVA which occurred at 6:45pm AEST on 09 August 2020. The weather corrected demand at the 50 POE level was 56.2 MVA. The power factor at the time of summer maximum demand was 1.0. The upward step change in the first year of forecast is due to the impact of load transfers to Kingsford zone substation.

Maximum demand has typically occurred in winter in past years, In the winter season, the maximum demand has recently occurred between 6:30pm and 7:30pm AEST.

Figure 3: Demand forecast at Kingsford zone substation

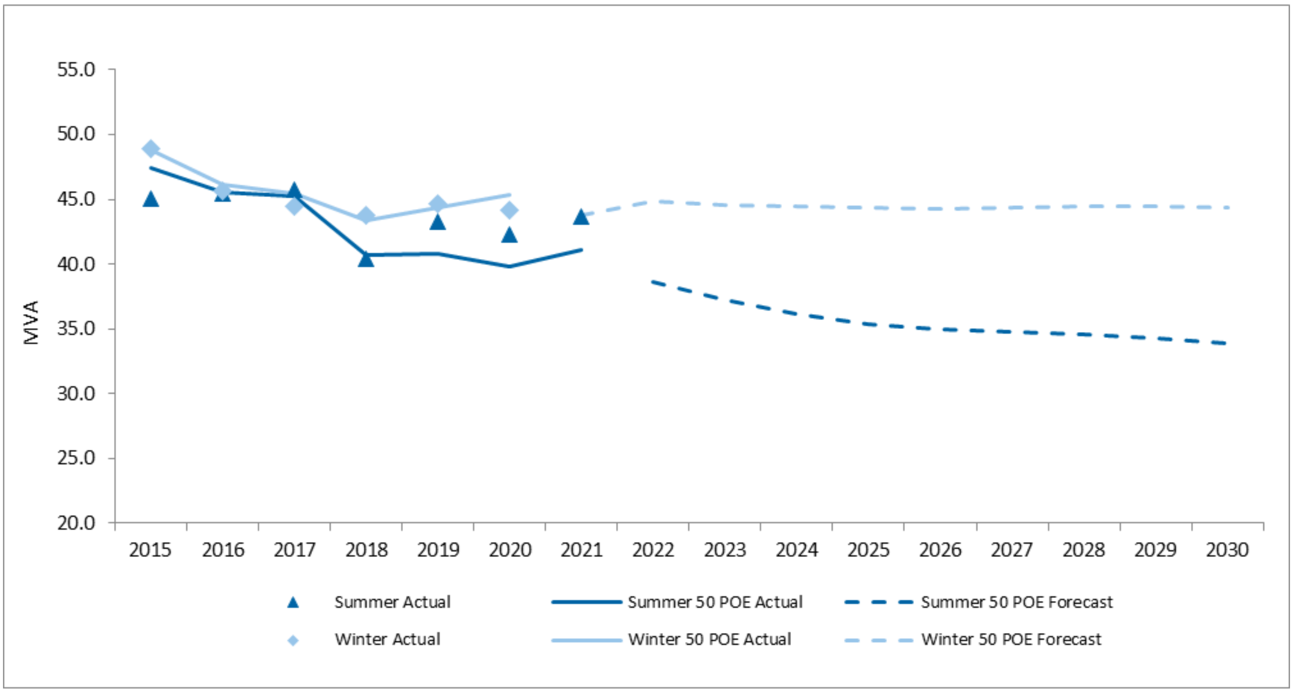


2.2.3 Demand forecast – Maroubra

Maroubra zone substation has a total capacity of 150.6 MVA and a firm capacity of 102.8 MVA. In 2020/2021 the maximum demand on the zone substation was 44.2 MVA which occurred at 6:45 AEST on 16 July 2020. The weather corrected demand at the 50 POE level was 45.3 MVA. The power factor at the time of summer maximum demand was 0.93.

Maximum demand has typically occurred in winter in past years, In the winter season, the maximum demand has recently occurred between 6:30pm and 7:30pm AEST.

Figure 4: Demand forecast at Maroubra zone substation

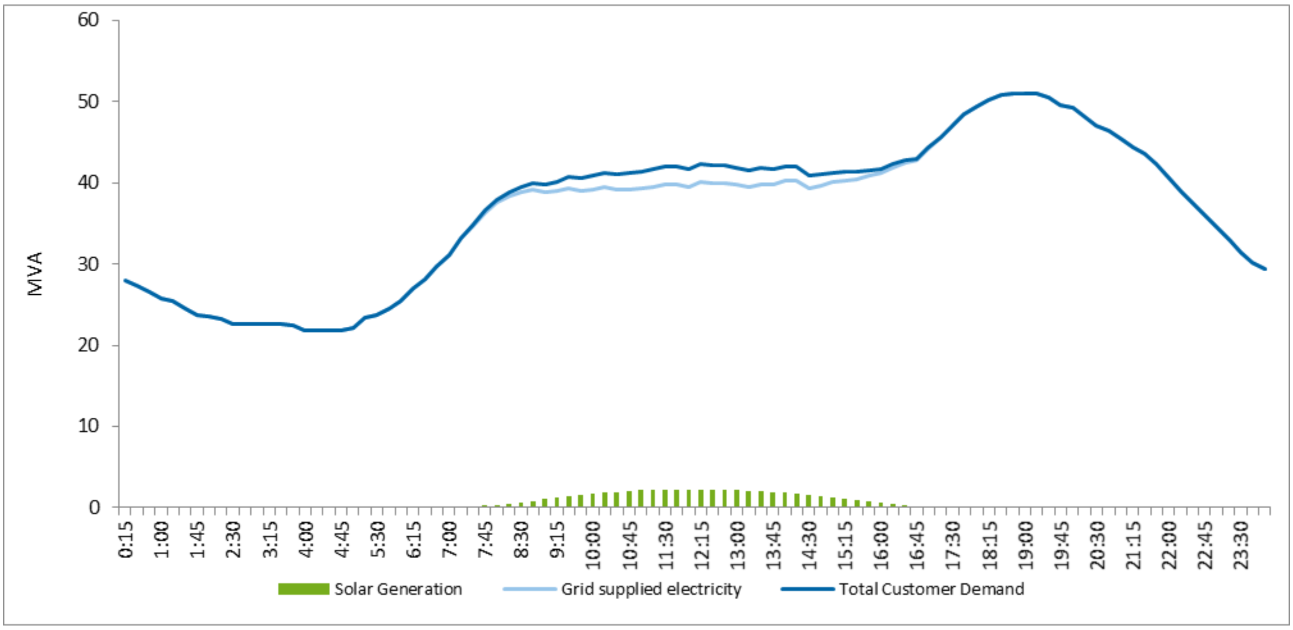


2.3 Pattern of use

2.3.1 Pattern of use – Clovelly

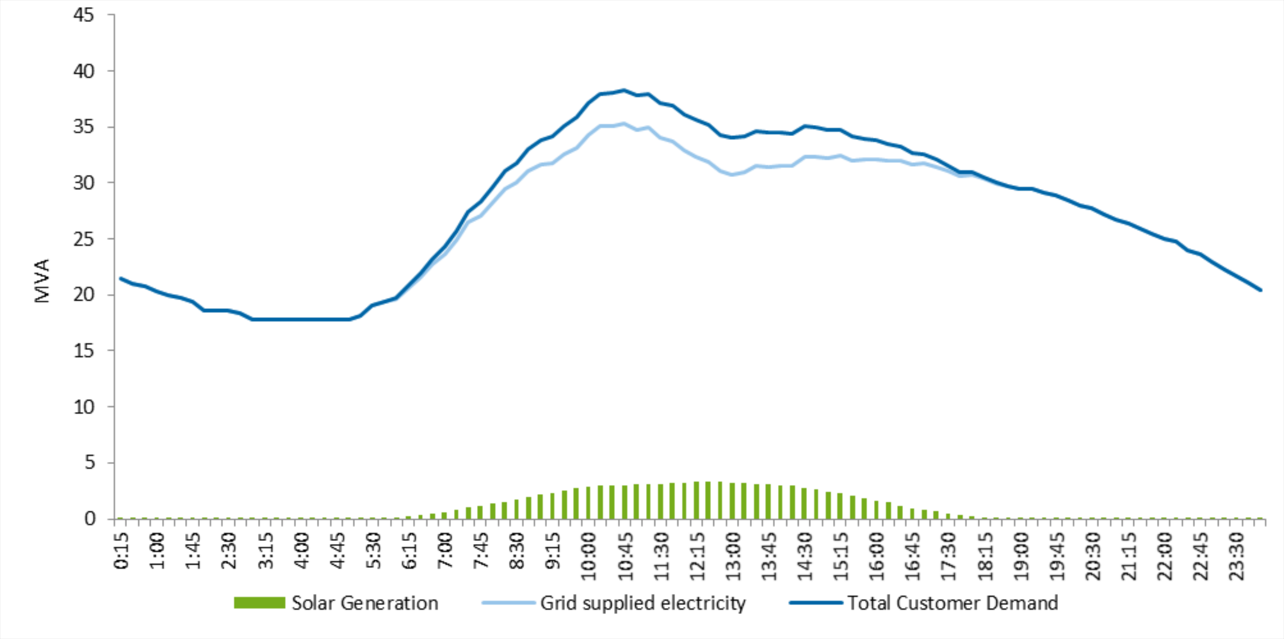
Over the past 7 years, annual maximum demand at Clovelly has mostly occurred in winter, with a time of peak typically between 7:00pm and 7:30pm AEST. Across winter 2020 and summer 2020/21, maximum demand at Kingsford occurred at 7:15pm AEST on 16 July 2020. There is a total connected Solar PV capacity of 5.0 MW for customers supplied from Clovelly ZS. During the winter 2020 peak day and time, these PV systems are estimated to generate 0 MW at time of peak. Figure 5 below shows the demand profile on this day, including the estimated contribution from customer solar power systems.

Figure 5 – Winter peak day demand profile and PV contribution at Clovelly ZS on 16 July 2020



During summer 2020/21, Clovelly ZS experienced its summer peak demand at 10:45am AEST on 18 December 2020. Figure 6 below shows the demand profile on this day including the contribution from customer solar power systems.

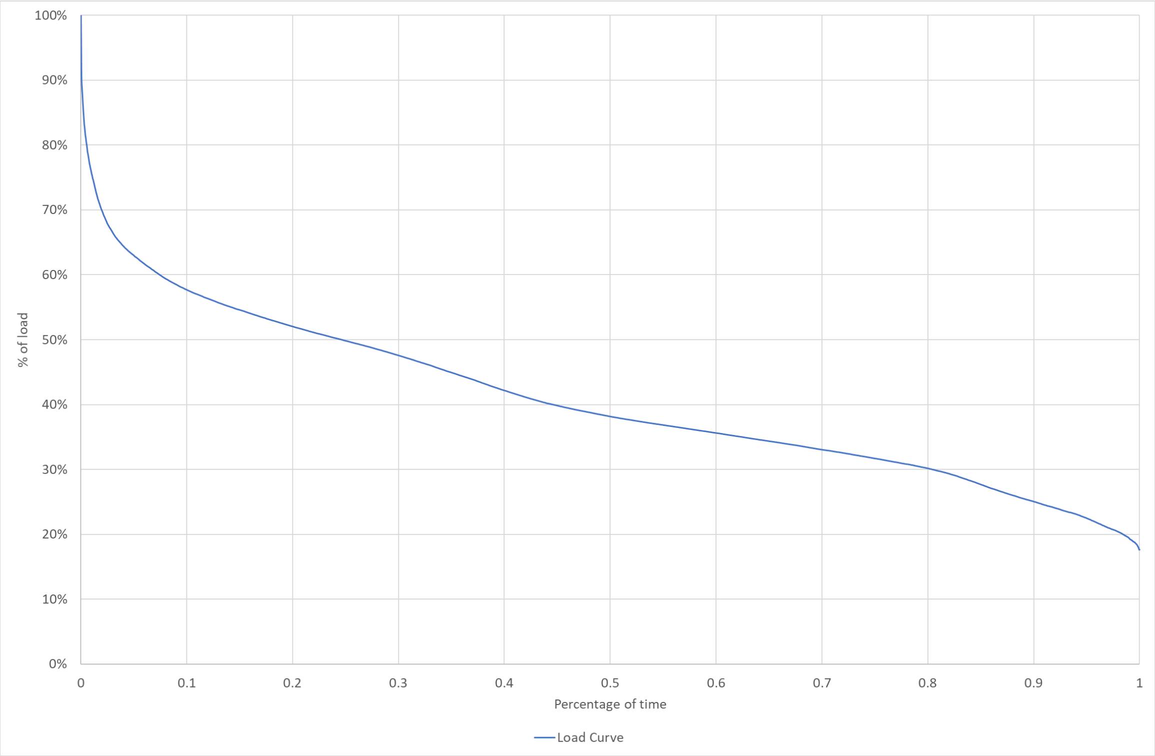
Figure 6 – Summer peak day demand profile and PV contribution at Clovelly ZS on 18 December 2020



No load transfer capability has been included at Clovelly ZS as there is negligible impact on the assessment of this project. The load duration curve for Clovelly ZS is shown in Figure 7 below.

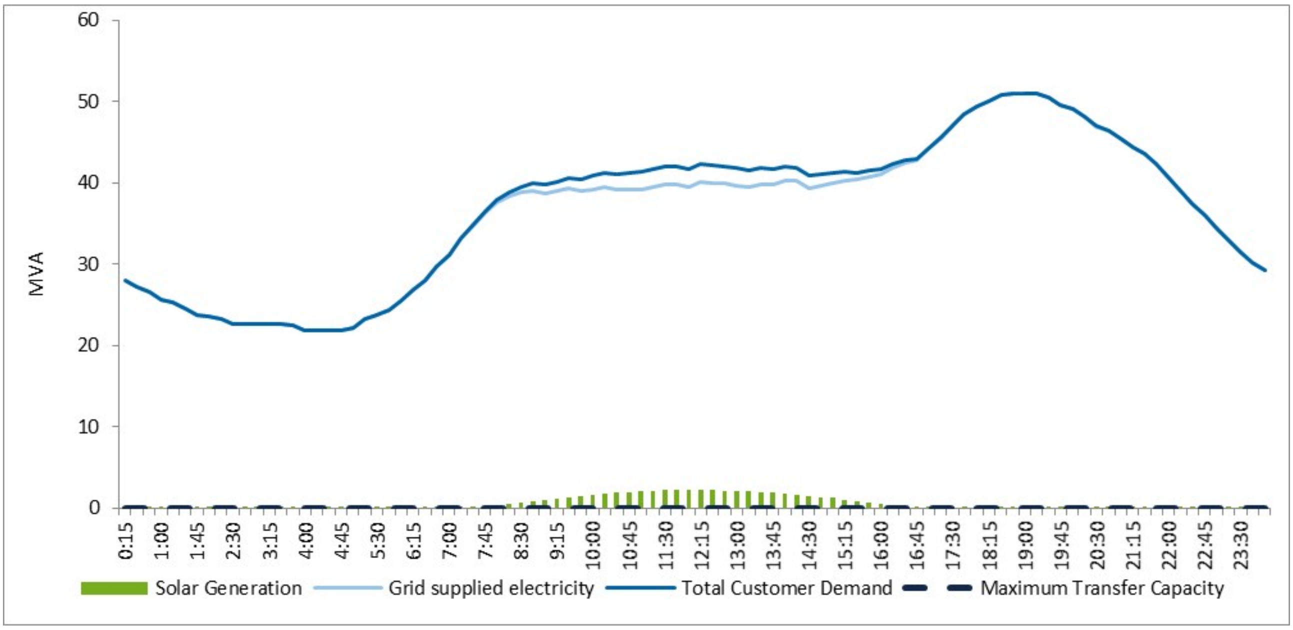
It is assumed that the load types supplied by this substation will not change substantially in the timeframe pertinent to this RIT-D assessment and therefore the load duration curve will maintain its characteristic shape. The load duration curve is used to determine the energy at risk and/or the amount of load curtailment required at certain load levels. It is a direct input into the modelling of the Expected Unserved Energy (EUE), which is the probability weighted amount of load that would be unmet due to network capacity limitations.

Figure 7: Clovelly ZS load duration curve



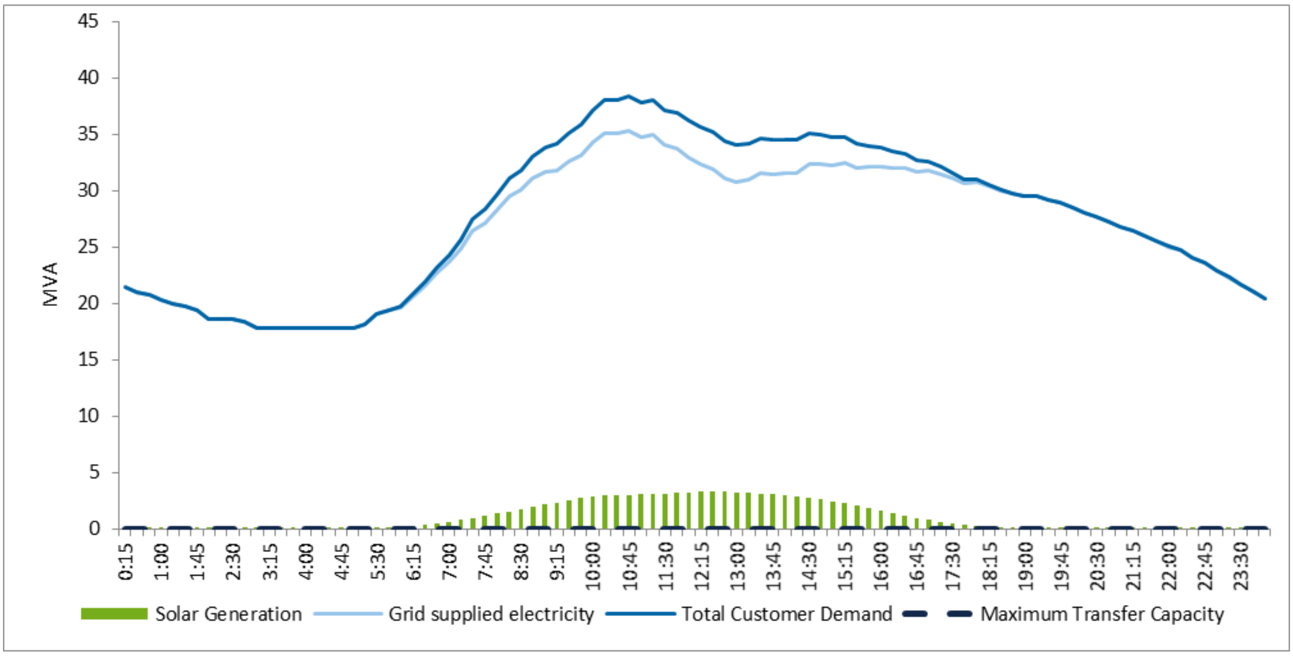
In the event of a network outage on a winter peak demand day, the shortfall in network supply would be the maximum demand on the day. The maximum shortfall would be around 51 MVA on 16 July 2020 as shown in Figure 8 below.

Figure 8: Winter peak day profile at Clovelly ZS showing maximum load transfer on 16 July 2020



Similarly, for a summer maximum demand day, there is a shortfall of supply of up to 35.3 MVA on 18 December 2020 (See Figure 9 below).

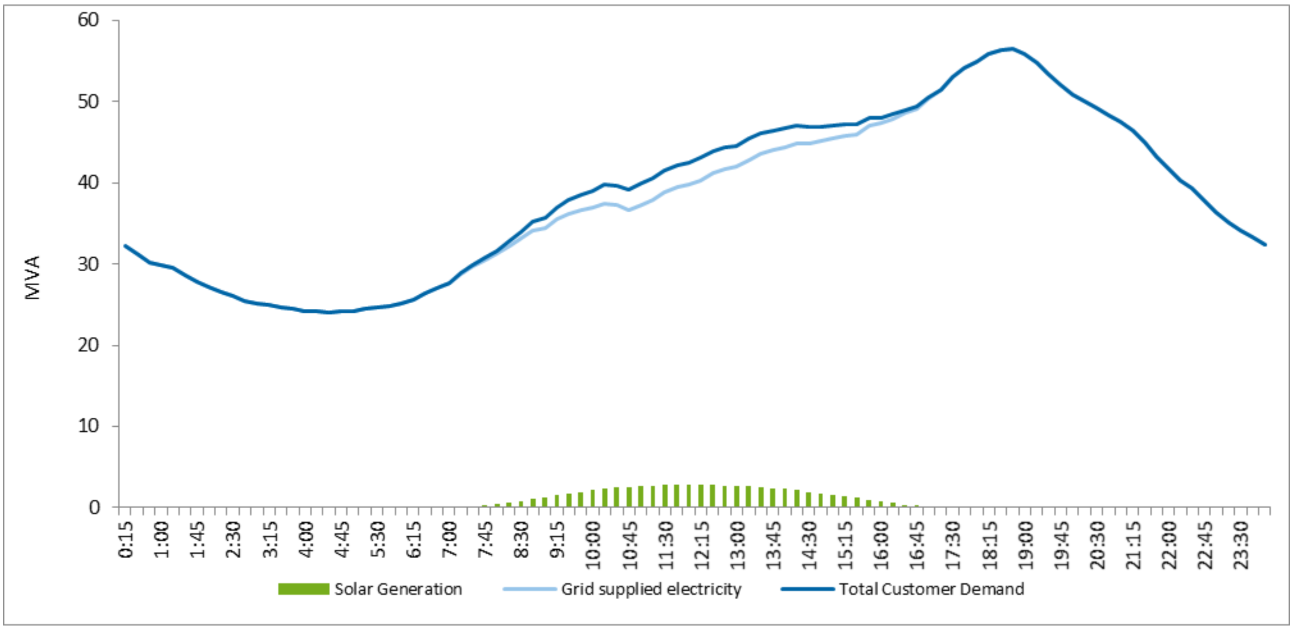
Figure 9: Summer peak day profile at Clovelly ZS showing maximum load transfer on 18 December 2020



2.3.2 Pattern of use – Kingsford

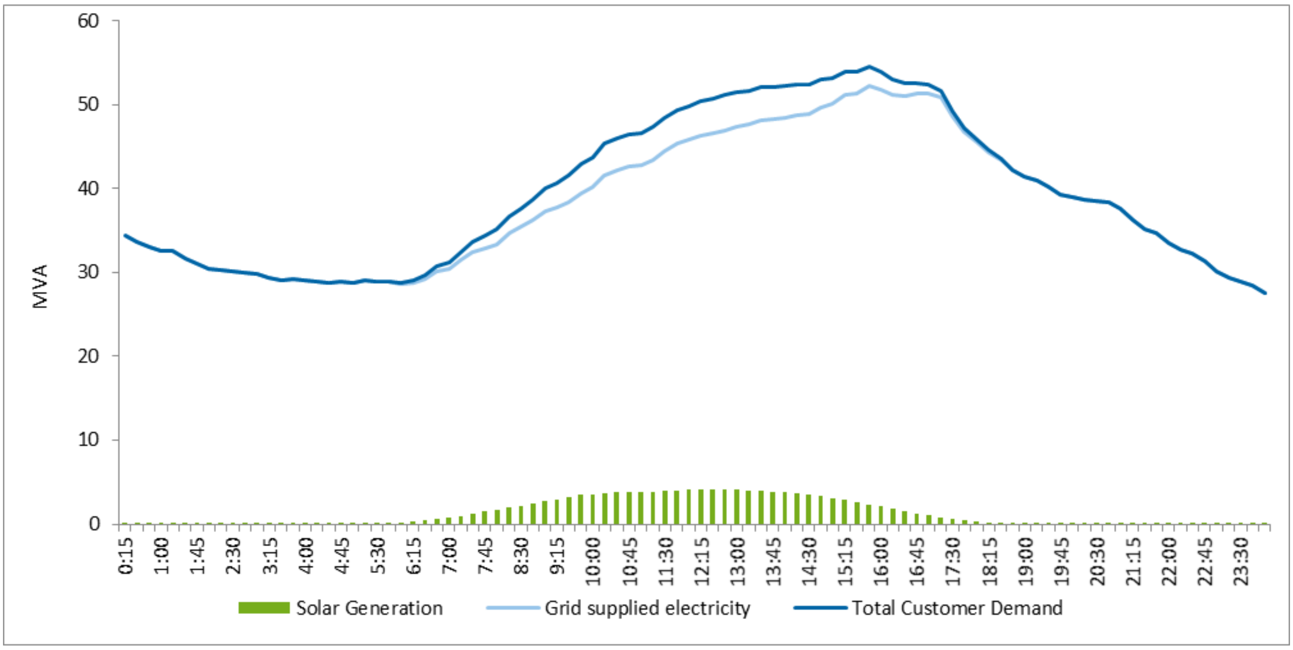
Over the past 7 years, annual maximum demand at Kingsford ZS has mostly occurred in winter, with a time of peak typically between 6:30pm and 7:30pm AEST. Across winter 2020 and summer 2020/21, maximum demand at Kingsford occurred at 6:45pm AEST on 9 August 2020. There is a total connected Solar PV capacity of 6.3 MW for customers supplied from Kingsford ZS. During the winter 2020 peak day and time, these PV systems are estimated to generate 0 MW at time of peak. Figure 10 below shows the demand profile on this day, including the estimated contribution from customer solar power systems.

Figure 10 – Winter peak day demand profile and PV contribution at Kingsford ZS on 9 August 2020



During summer 2020/21, Kingsford ZS experienced its summer peak demand at 3:45pm AEST on 29 November 2020. Figure 11 below shows the demand profile on this day including the contribution from customer solar power systems.

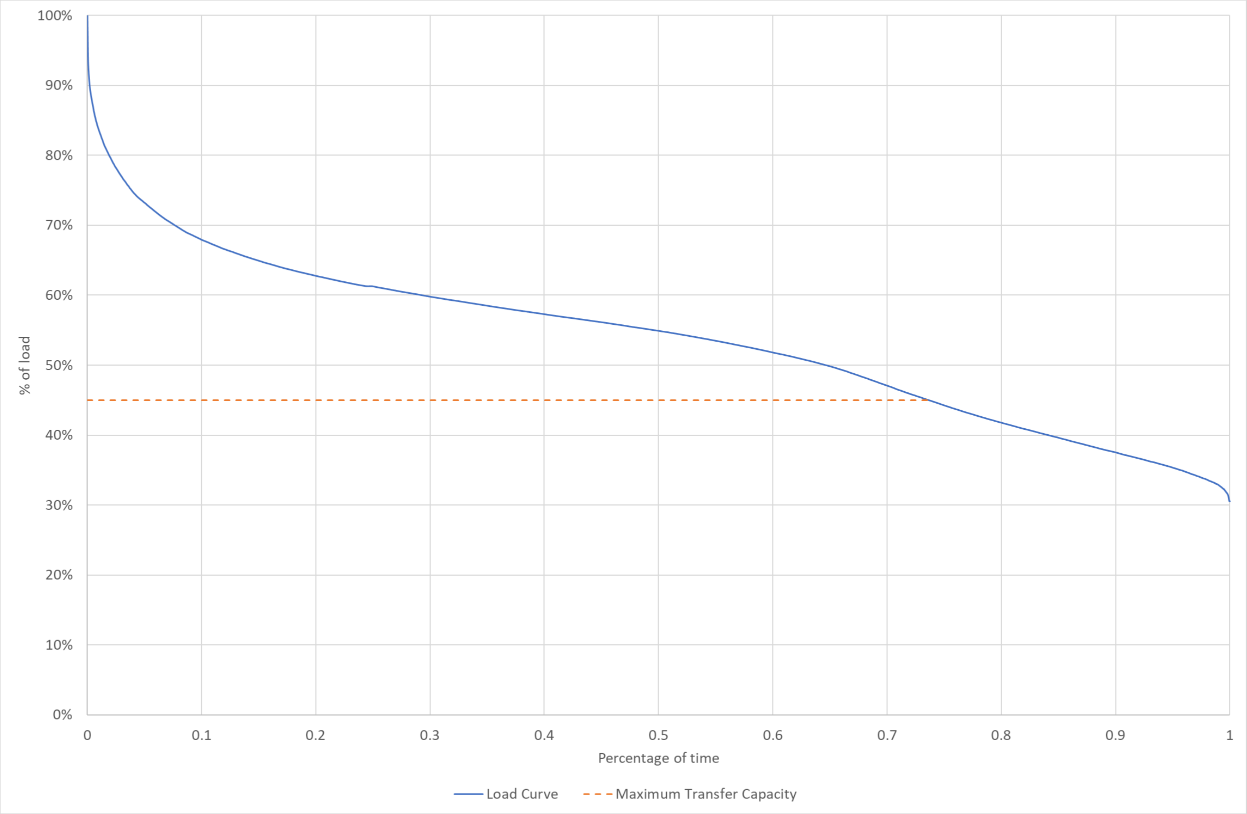
Figure 11 – Summer peak day demand profile and PV contribution at Kingsford ZS on 29 November 2020



Currently, the emergency load transfer capacity for Kingsford ZS is about 25 MVA or 45% of the maximum demand that occurs in the winter. Maximum demand exceeds the load transfer capacity for over 70% of the year. The load duration curve, including the load transfer capacity excluding transfers to Maroubra ZS, is shown in Figure 12 below.

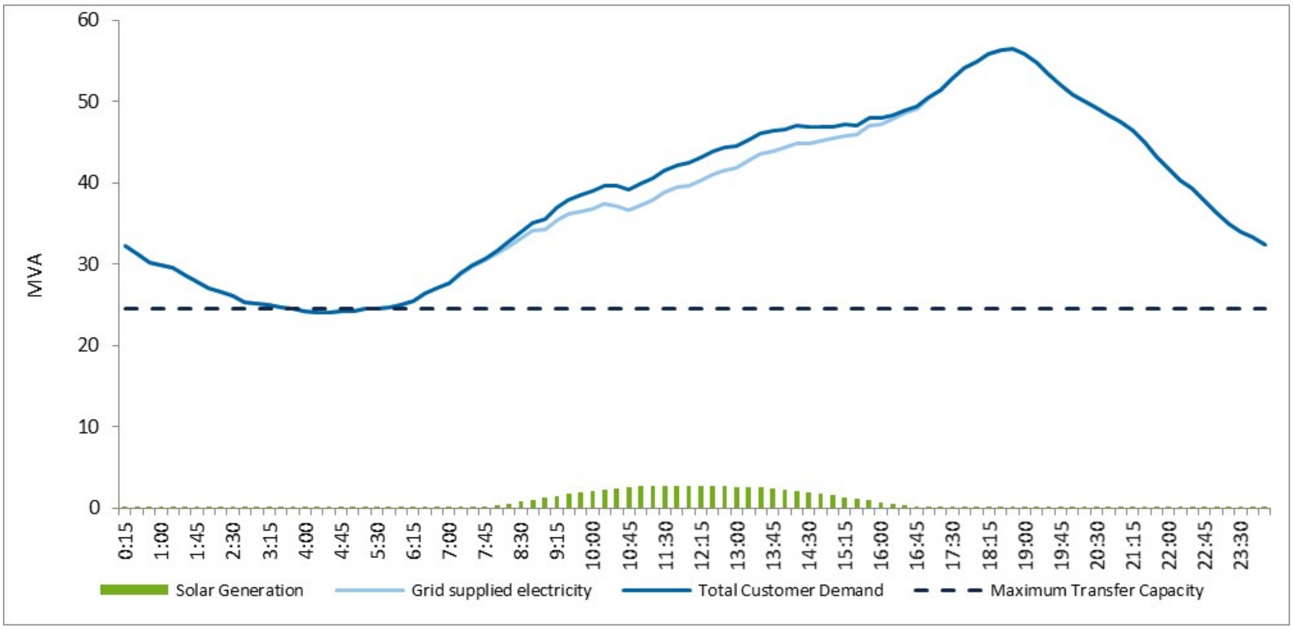
It is assumed that the load types supplied by this substation will not change substantially in the timeframe pertinent to this RIT-D and therefore the load duration curve will maintain its characteristic shape. The load duration curve is used to determine the energy at risk and/or the amount of load curtailment required at certain load levels. It is a direct input into the modelling of the Expected Unserved Energy (EUE), which is the probability weighted amount of load that would be unmet due to network capacity limitations.

Figure 12: Kingsford ZS load duration curve



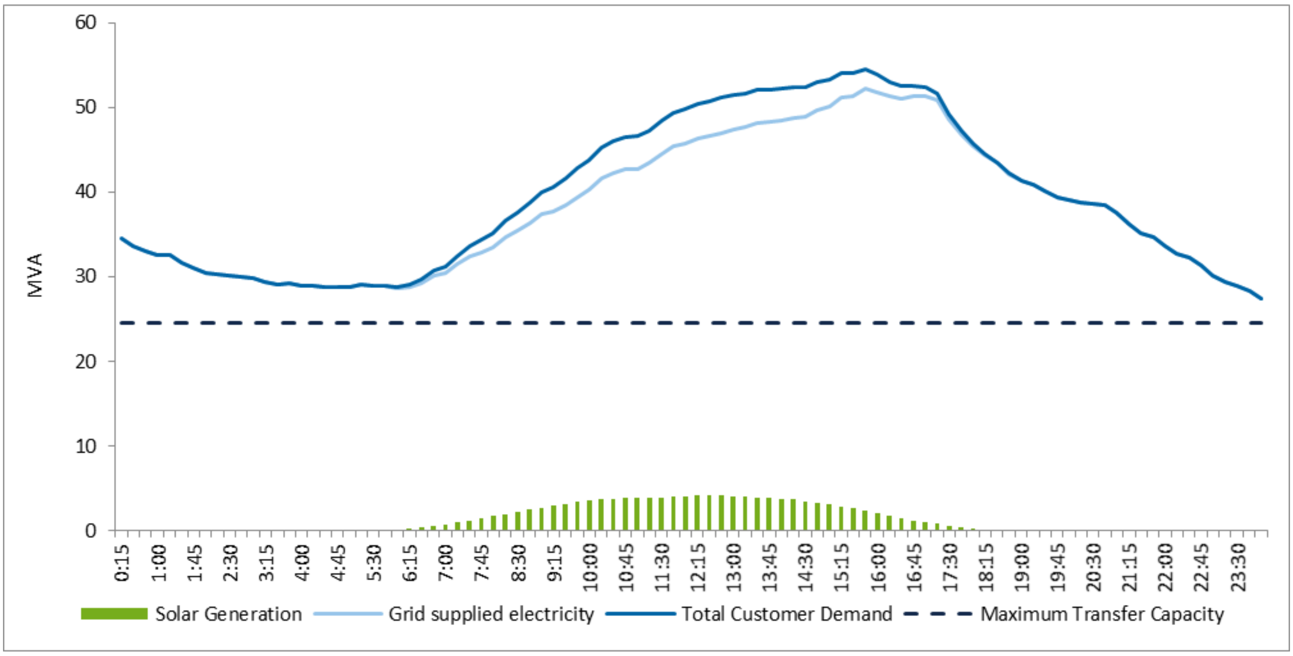
In the event of a network outage on a winter peak demand day, the shortfall in network supply would be for almost the entire day after realising the maximum load transfer capacity. The maximum shortfall would be around 32 MVA on 9 August 2020 as shown in Figure 13 below.

Figure 13: Winter peak day profile at Kingsford ZS showing maximum load transfer on 9 August 2020



Similarly, in the event of a network outage on a summer peak demand day, there is a supply shortfall for the entire day with a maximum shortfall of up to 28 MVA following realisation of the maximum transfer capacity (see Figure 14 below).

Figure 14: Summer peak day profile at Kingsford ZS showing maximum load transfer on 29 November 2020

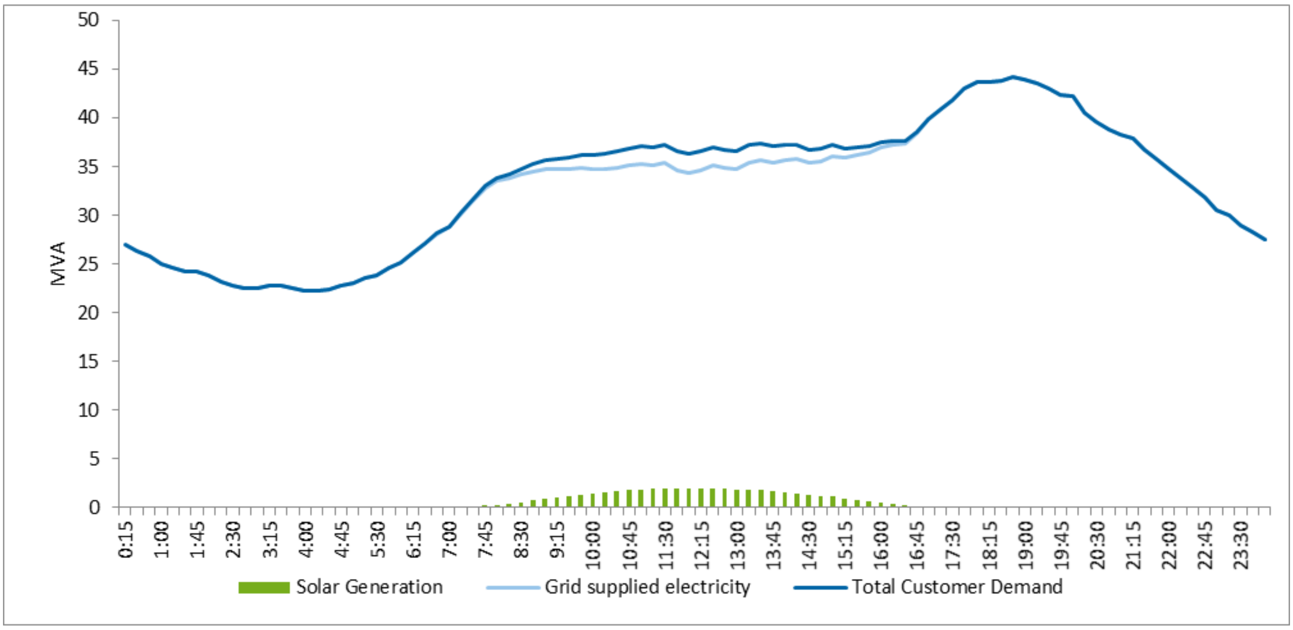


2.3.3 Pattern of use – Maroubra ZS

Over the past 7 years, annual maximum demand at Maroubra ZS has occurred in winter, with a time of peak typically between 6:30pm and 7:30pm AEST.

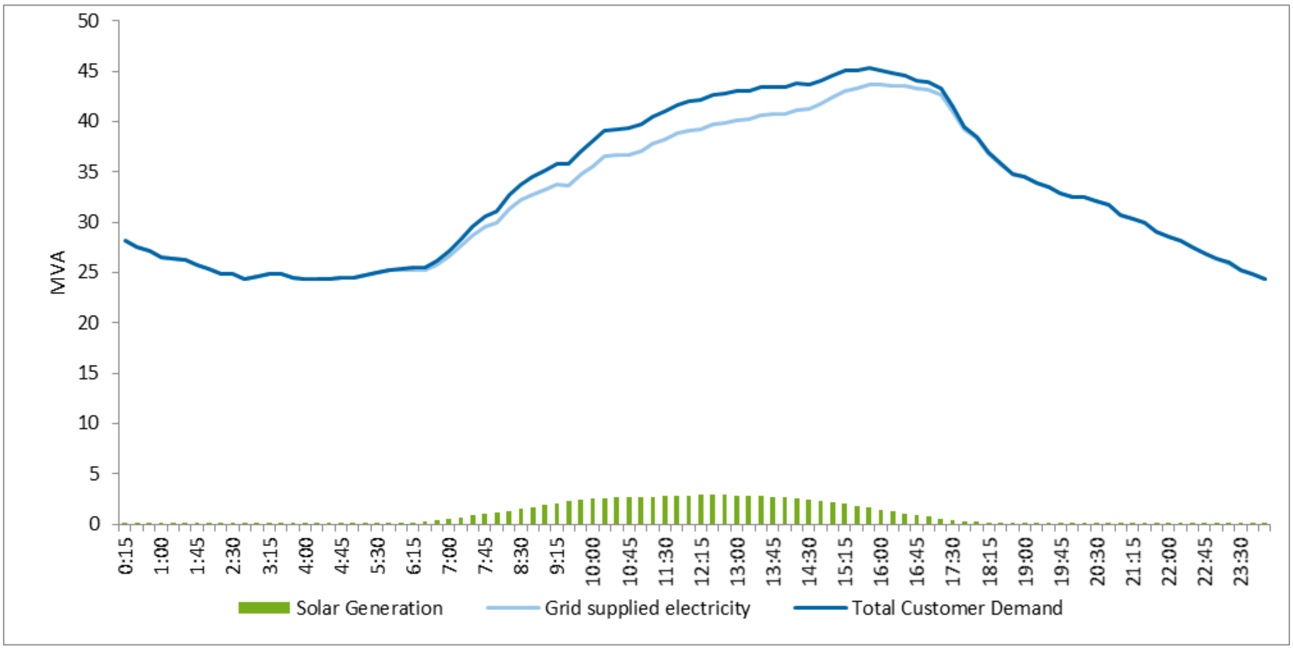
There is a total Solar PV capacity of 4.4 MW connected to Maroubra ZS. At the peak time of 6:45pm AEST on 16 July 2020, these PV systems are estimated to generate 0 MW at time of peak. Figure 15 below shows the load trace on this day including the contribution from customer solar power systems.

Figure 15: Winter peak day demand profile and PV contribution at Maroubra on 16 July 2020



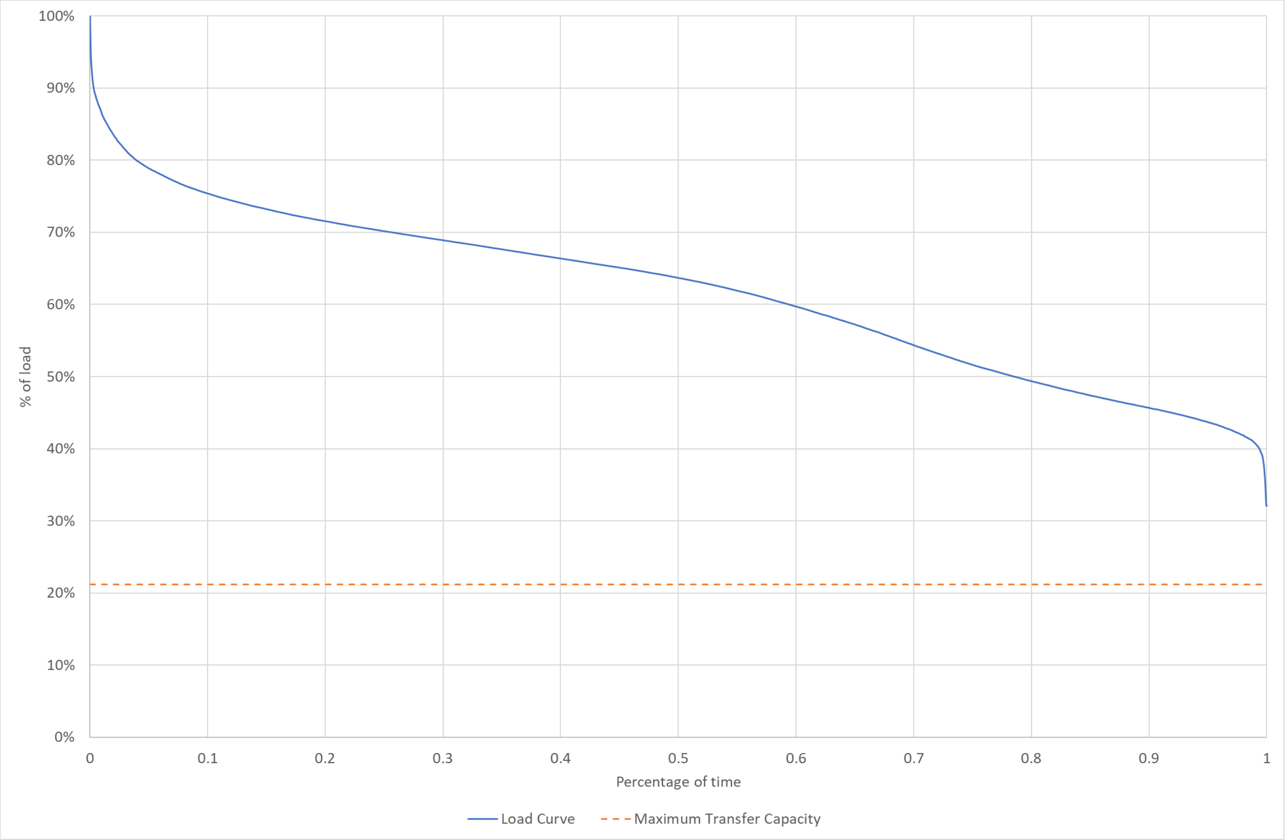
During summer 2020/21, Maroubra ZS experienced its summer peak demand at 3:45pm AEST on 29 November 2020. Figure 16 below shows the demand profile on this day including the contribution from customer solar power systems.

Figure 16: Summer peak day demand profile and PV contribution at Maroubra ZS on 29 November 2020



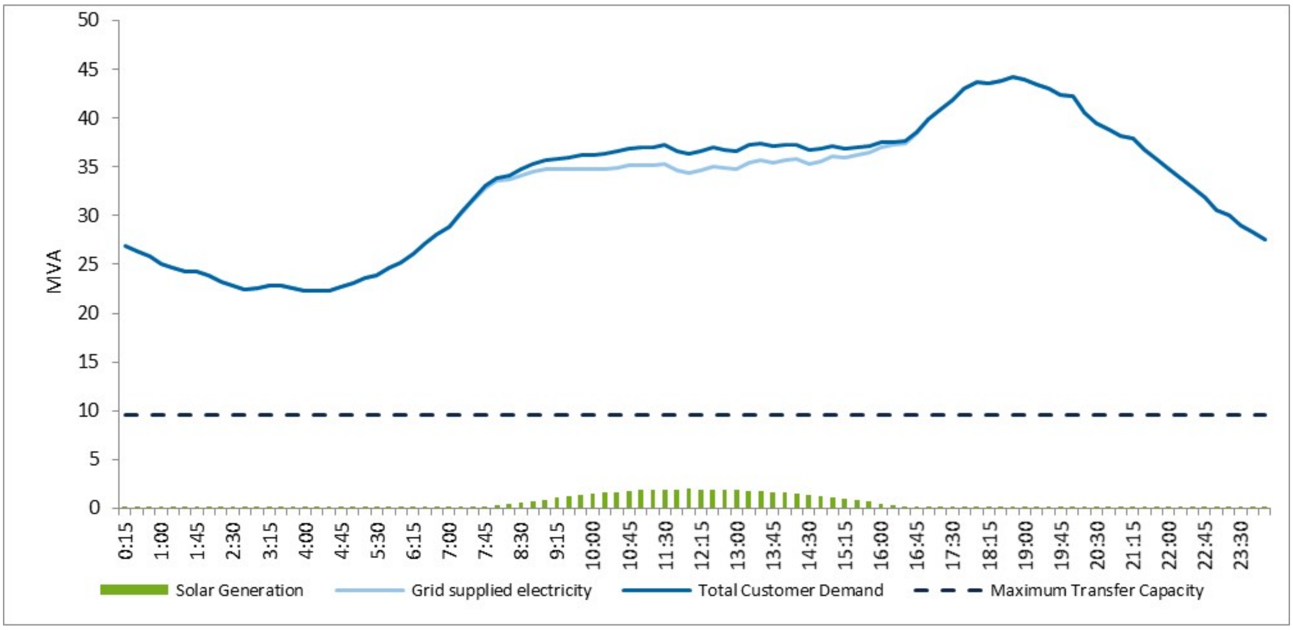
Maroubra ZS currently has a load transfer capacity of 10 MVA or about 22% of both the winter 2020 and summer 2020/21 maximum demands. Electricity demand exceeds the transfer capacity for 100% of the year. The load duration curve, including the load transfer capacity excluding Kingsford, is shown in Figure 17 below. It is assumed that the load types supplied by this substation will not change substantially in the timeframe pertinent to this RIT-D and therefore the load duration curve will maintain its characteristic shape.

Figure 17: Maroubra ZS load duration curve



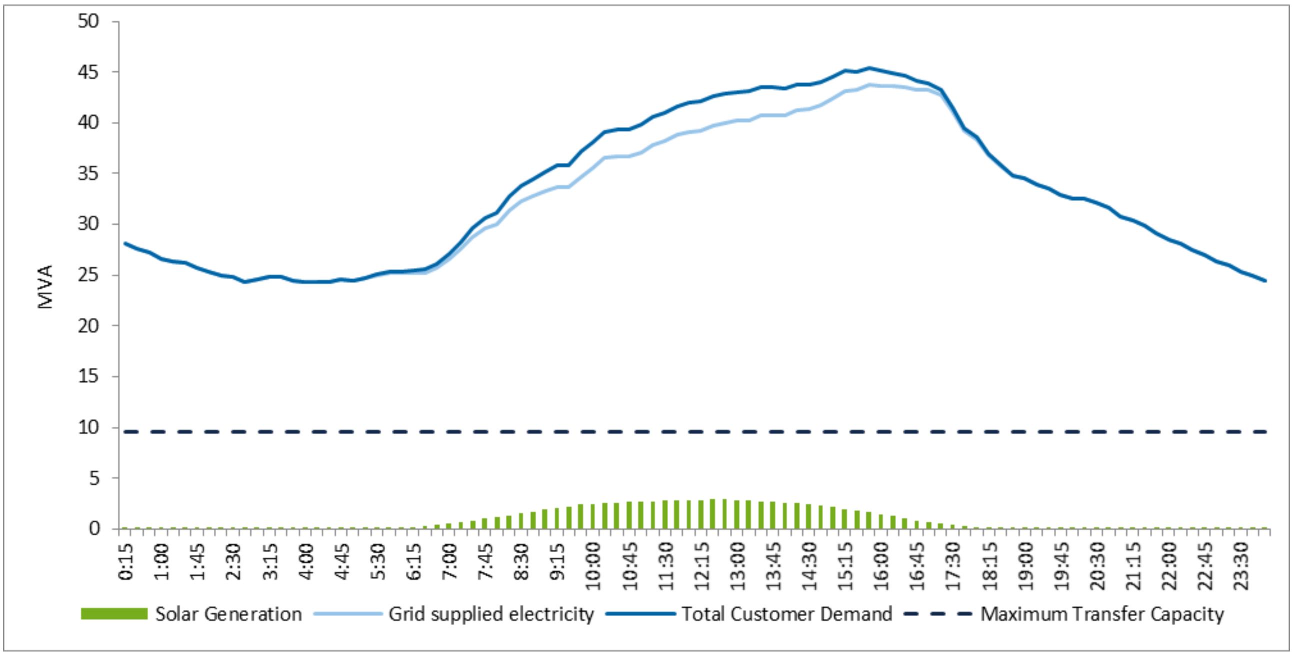
In the event of a network outage on a winter maximum demand day and following realisation of the maximum transfer capacity through network switching, there would be a supply shortfall for the entire day with a maximum shortfall of around 35 MVA (see Figure 18 below).

Figure 18: Winter peak day profile at Maroubra ZS showing maximum load transfer 16 July 2020



Similarly, for a summer peak demand day, the shortfall in network supply would be for the entire day after realising the maximum load transfer capacity. The maximum shortfall would be around 34 MVA (See Figure 19 below)

Figure 19: Summer peak day profile at Maroubra ZS showing maximum load transfer 29 November 2020



2.4 Customer characteristics

Clovelly, Kingsford and Maroubra zone substations serve a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2020/21 period is as follows:

Table 1: Customer characteristics – Clovelly ZS

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	16,769	2,120	80	18,969
% of Customers	88.4%	11.2%	0.4%	
Annual Consumption (MWh)	62,876	21,919	64,907	149,702
% of Annual Consumption	42.0%	14.6%	43.4%	
Number of Solar Customers	489	165	7	661
% of Solar Customers	74%	25.0%	1.1%	
Average Annual Consumption(MWh)	3.7	10	811	

About 20% of residential customers live in detached homes with an average usage of about 6.0 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.1 MWh per year.

Table 2: Customer characteristics – Kingsford ZS

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	22,872	2,783	86	25,741
% of Customers	88.9%	10.8%	0.3%	
Annual Consumption (MWh)	89,449	30,111	122,476	242,037
% of Annual Consumption	37.0%	12.4%	50.6%	
Number of Solar Customers	865	279	8	1,152
% of Solar Customers	75%	24.2%	0.7%	
Average Annual Consumption(MWh)	3.9	11	1,424	3.9

About 28% of residential customers live in detached homes with an average usage of about 6.1 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.0 MWh per year.

Table 3: Customer characteristics – Maroubra ZS

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	14,477	2,514	112	17,103
% of Customers	84.6%	14.7%	0.7%	
Annual Consumption (MWh)	54,453	23,475	109,215	187,143
% of Annual Consumption	29.1%	12.5%	58.4%	
Number of Solar Customers	693	207	6	906
% of Solar Customers	76%	22.8%	0.7%	
Average Annual Consumption(MWh)	3.8	9	975	

About 35% of residential customers live in detached homes with an average usage of about 5.4 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 2.8 MWh per year.

3 Aged asset issues

Feeder 264 is a SCFF cable commissioned in 1977. It is approximately 5.5km long and connects Kingsford ZS with Bunnerong Subtransmission Switching Station (**STSS**). Its availability is critical to supplying zone substations connected to the ring in the event of an outage of any one of the other cables, as shown in Figure 1 on page 3.

A critical assumption underpinning the identified need is that retaining the SCFF 132kV Feeder 264 is expected to increase the risk of involuntary load shedding. The major factor contributing to the risk of involuntary load shedding is the age of the feeder which is reaching the end of its technical life. SCFF cable technology is obsolete and requires specialist skills to repair and maintain. Outage times can be lengthy and spares are not readily available.

Feeder 264 has experienced multiple oil leaks over the past 15 years. Analysis of the condition of Feeder 264 has determined that the risk of prolonged outages is growing.

4 Proposed preferred network option

This section provides details of the options that Ausgrid identified in the network planning process and identification of the proposed preferred option. Ausgrid has identified a single credible option of undertaking a like-for-like replacement of the existing feeder. Other options could technically address the identified need, but are likely to cost significantly more than the credible option identified without any corresponding increase in benefits. The single credible option is summarised below. All costs in this section are in $2021/22, unless otherwise stated.

Table 4: Summary of the credible options considered

Option Details	Option 1
Option description	Replace 132kV feeder 264 from Beaconsfield BSP to Kingsford ZS like-for-like
Capital Costs	$25.1 million
Construction period	From 2022/23 to 2023/24
Commissioning date	2023/24

Ausgrid also considered one additional network option involving the decommissioning of the existing Feeder 264 and no works considered to replace the subtransmission feeder. However, this option was ruled out as it leaves the remaining network unsecure.

Ausgrid has elected to assess three alternative future scenarios – namely:

- low benefit scenario – Ausgrid has adopted a number of assumptions that give rise to a lower bound NPV estimate for each credible option, in order to represent a conservative future state of the world with respect to potential market benefits that could be realised under each credible option;
- baseline scenario – the baseline scenario consists of assumptions that reflect Ausgrid's central set of variable estimates which, in Ausgrid's opinion, provides the most likely scenario; and
- high benefit scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected market benefits.

A summary of the key variables in each scenario is provided in the table below.

Table 5: Summary of the three scenarios investigated

Variable	Scenario 1 – baseline	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand	POE50	POE90	POE10
VCR	$43.69/kWh (Derived from the AER VCR 2019 estimates and updated by CPI variations authorised by AER)	$30.58/kWh (30 per cent lower than the central, AER-derived estimate)	$56.79/kWh (30 per cent higher than the central, AER-derived estimate)
Capital Costs (including future capital costs)	100 per cent of capital cost estimate	125 per cent of capital cost estimate	75 per cent of capital cost estimate
Discount Rate	2.99%	2.99%	4.05%

Refer to the Draft Project Assessment Report for this project for further details about the options assessment methodology and scenario analysis.

Preferred option at this draft stage

The single credible option satisfies the RIT-D. It involves the replacement of the existing SCFF Feeder from Beaconsfield BSP to Kingsford ZS with a new 132kV feeder 5.5km long. Once installed, the existing SCFF feeder will be decommissioned.

The estimated capital cost of this option is $25.1 million. Ausgrid assumes that the necessary construction to install the new feeders would commence in 2022/23 and end in 2023/24. Once the new installation is complete, operating costs are expected to be approximately $48,000 per annum (around 0.2 per cent of capital expenditure).

Refer to the Draft Project Assessment Report for this project for further details about the options assessment.

5 Assessment of non-network solutions

5.1 Required demand management characteristics

As noted in Section 2, a concurrent outage on this feeder at the same time as outage on Feeder 265 and Feeder 262 would result in loss of supply to Clovelly, Kingsford and Maroubra zone substations, approximately 60,000 customers. In 2023/24, the expected completion date of the proposed preferred network option, up to 117 MVA of customer demand supplied by Clovelly, Kingsford and Maroubra would be lost, after realising available transfer capability.

To be considered a feasible option, any demand management solution must be technically feasible, commercially feasible; and able to be implemented in sufficient time by 2022/23 for deferral of the network investment.

5.2 Available demand management funds

To identify the available funds for a possible demand management solution, the net NPV benefit for the network option is compared against the net NPV benefit of a deferral of the preferred network option.

Table 6 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years.

Table 6 – Required combined demand reductions at Clovelly, Kingsford and Maroubra zones

Required peak demand reduction	Available funds		
	1 Yr deferral	2 Yr deferral	3 Yr deferral
22 MVA	$19,000	NIL	NIL

Demand management funds are very limited:

- For a 1-year deferral, due to the low load transfer capacity and very high unserved energy that must be met across Clovelly, Kingsford and Maroubra zones, the available funds are about $19,000 for a peak demand reduction of 22 MVA. This is equivalent to $0.86/kVA, which is extremely low; and
- For 2 and 3-year deferrals the NPV is lower than the NPV of the proposed preferred network option, hence zero budget is available for these deferral scenarios.

The above figures already account for maximum load transfer capacity out of the load areas and assumes this capacity can be fully realised. This is also the case for determining the feasibility of demand management solutions as outlined in section 5.3 below.

5.3 Demand management options considered

Ausgrid has considered a number of demand management solutions to determine their commercial and technical feasibility to assist with the identified need for Feeder 264. Each of the demand management solutions considered is summarised below.

5.3.1 Customer power factor correction

As a mature and proven demand management solution, customer power factor correction is both technically feasible and offers reliable permanent reductions sufficient at a low cost. Analysis of customer interval data indicates a commercial potential of around 1.8 MVA across Clovelly, Kingsford and Maroubra zones. At a projected demand management cost of about $25-50 per kVA, the estimated cost to achieve commercial potential is about $38k – $75k.

This solution would contribute less than 7% of the required 22 MVA demand reduction at a cost that is, at minimum, the entire available funds. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

5.3.2 Customer solar power systems

A possible demand management solution might be to provide a financial incentive to customers to invest in new solar power systems such that an accelerated take-up of solar reduces the forecast demand and energy overload conditions. Analysis of interval data for Clovelly, Kingsford and Maroubra zones shows that while solar generation is partially coincident with the energy shortfall, it offers no reduction in load during non-solar hours, including at times of winter peak demand. As the shortfall is across all hours (base load of around 64 MVA on peak winter day), a non-dispatchable solar power system would offer no support outside of daylight hours.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical incentive program to encourage customer investment in solar power. If we assumed that incentives of about 25% of customer investment might encourage additional customer take-up of solar that would otherwise not occur, an incentive of about $250 per kVA would, for example, incentivise an additional 1 MW of customer solar power systems requiring a total customer incentive payment of about $250k, which is significantly higher than the available funds for a 1-year deferral. As solar power system generation is subject to hourly, seasonal and cloud cover variation, an example 1 MW solar array is estimated to generate up to 1.4GWh annually, equivalent to only 0.3% of the present annual net energy consumption from customers connected to Clovelly, Kingsford and Maroubra zones.

This indicates that customer solar power system would address an insignificant component of the energy shortfall. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

5.3.3 Customer energy efficiency

Customer energy efficiency improvements as a demand management solution provides a financial incentive to customers to accelerate take-up of energy efficiency improvements with the aim of reducing their forecast energy consumption and the impact of overload conditions.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical incentive program to encourage customer investment in energy efficiency improvements. If we assumed that incentives of about 20-40% of customer investment might encourage additional customer take-up of energy efficiency improvements than would otherwise occur, an incentive of about $200-500 per kVA incentive might achieve up to 0.1-0.2 MVA and 0.1-0.3 GWh in annual energy efficiency savings using 100% of the available funds for a 1-year deferral. This would address only a small component of the energy shortfall. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

5.3.4 Demand response

Demand response is a common demand management option and offers a relatively mature solution for standard network overload needs. Demand response can involve either or both a temporary reduction in customer load and the use of embedded generation to either replace grid supplied electricity to the customer or export to the local grid.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical demand response program that reduced peak demand for the top 100-200 hours. Past practice shows that costs for traditional demand response from commercial and industrial (C&I) customers is in the range of $50-150 per kW for 40-100 hours of dispatch and 3-5 months availability. If it was assumed that demand response could be acquired for an estimated $75-125 per kVA per year for 12 months availability, the available funds would fund less than 1 MW of demand response. As this solution would only address a very small component of the energy and demand shortfall, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

5.3.5 Large customer energy storage

While this option is technically feasible and offers a viable form of demand response, current and near-term pricing indicates that the solution would not be economic in comparison with demand response. At an estimated cost of over $1m per MWh, a peak lopping storage solution to address the top 100-200 hours would need to leverage significant other market benefits to be viable and yet would only address a very small component of the energy shortfall. We therefore consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

6 Conclusion

Based on the demand management options considered in Section 5, it is not considered possible that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make project deferral technically and economically viable. Consequently, a Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.