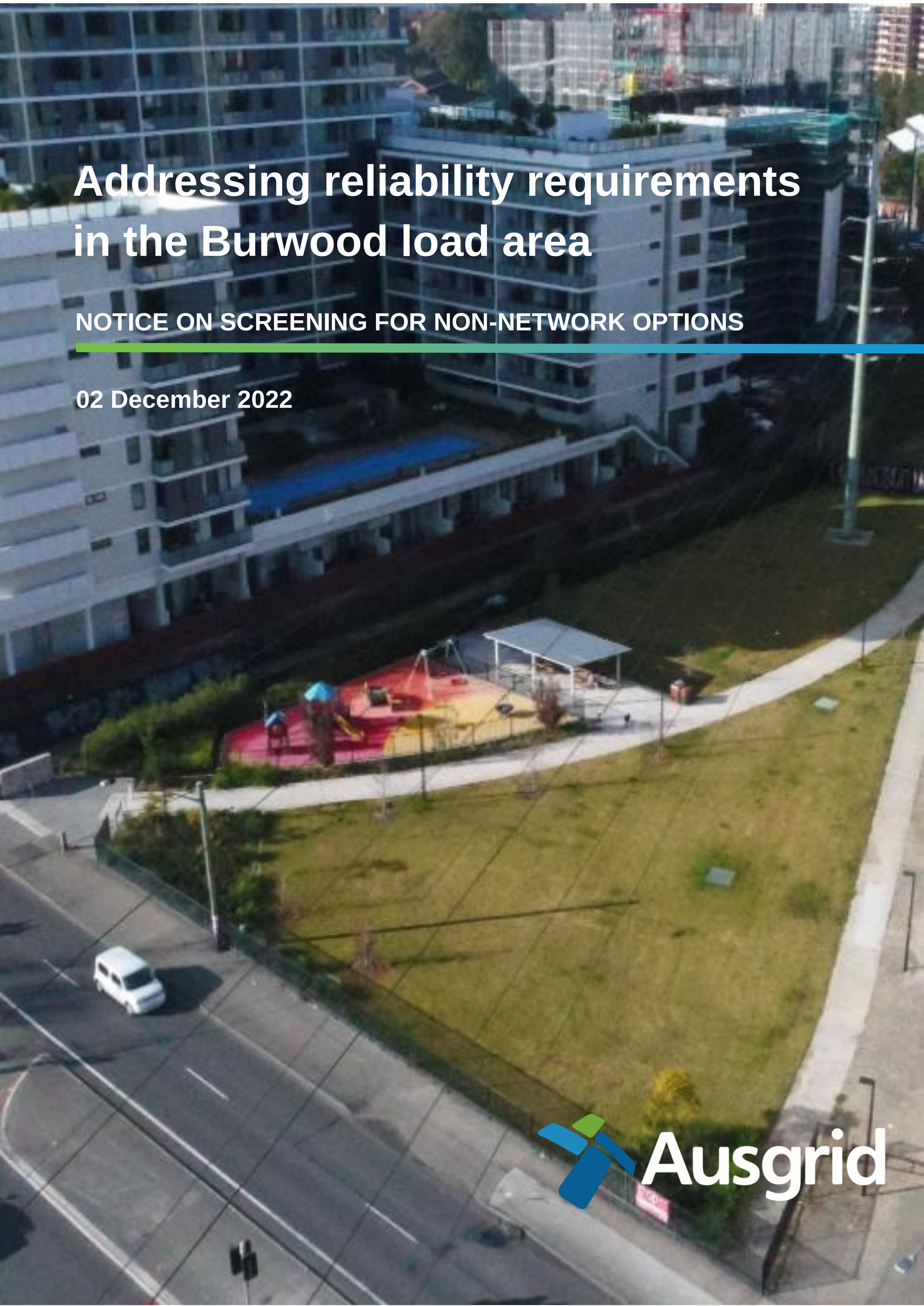
Addressing reliability requirements in the Burwood load area

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

02 December 2022



Addressing reliability requirements in the Burwood load area

Notice on screening for Non-Network Options – 2 December 2022

Contents

Disclaimer

Ausgrid is registered as both a Distribution Network Service Provider and a Transmission Network Service Provider. This notice on screening for SAPS and 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 132kV electricity subtransmission cables ('feeders') 923 and 924 are part of Ausgrid's Inner West network, connecting the Burwood Zone Substation (**ZS**) to the Mason Park subtransmission switching station (**STSS**), via the Strathfield Transition Point (**TP**). The feeders serve approximately 27,000 customers, including large commercial loads such as the Burwood Westfield and the Strathfield Plaza.

These underground feeders are of the self-contained fluid filled (**SCFF**) type, which are considered an obsolete and outdated technology. They were commissioned in the 1970s and are now reaching the end of their service life. They are becoming less reliable and approaching the point at which their replacement maximises the net benefit for the community.

Ausgrid's planning studies indicate that there will be substantial Expected Unserved Energy (**EUE**) to loads in this area of our network if these cables fail, as well as reactive maintenance costs associated with having to repair and restore service, and environmental risks from oil leaking from the cables. If action is not taken, it is expected that Ausgrid's electricity distribution license reliability and performance standards will be breached.

Ausgrid is therefore undertaking a RIT-D to assess options for addressing the risk associated with the ageing underground SCFF sections of feeders 923 and 924, to ensure we continue to satisfy our reliability and performance standards.

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.

This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ausgrid's determination that no SAPS or non-network option forms all or 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).

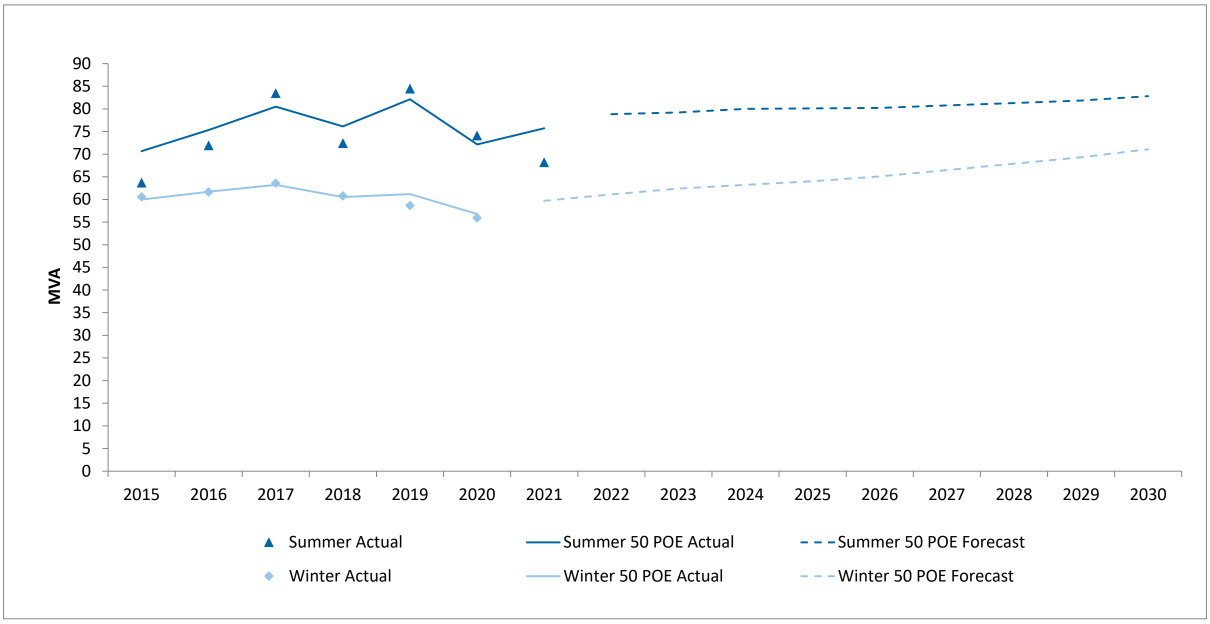
2 Forecast load and capacity

2.1 Demand forecast

Figure 1**Error! Reference source not found.** below shows the historical actual demand, the 50% Probability of Exceedance level (50 POE) weather corrected historical actual demand and the 50 POE forecast demand in both winter and summer at Burwood ZS.

Burwood ZS has a total capacity of 152.4 MVA and a firm capacity of 83.6 MVA. In 2020/21, the maximum demand on the ZS was 68.2 MVA at 3:45pm AEDT on 29 November 2020. The weather corrected demand at the 50 POE level was 75.7 MVA. The power factor at the time of summer maximum demand was 0.991.

Figure 1: Demand forecast at Burwood ZS

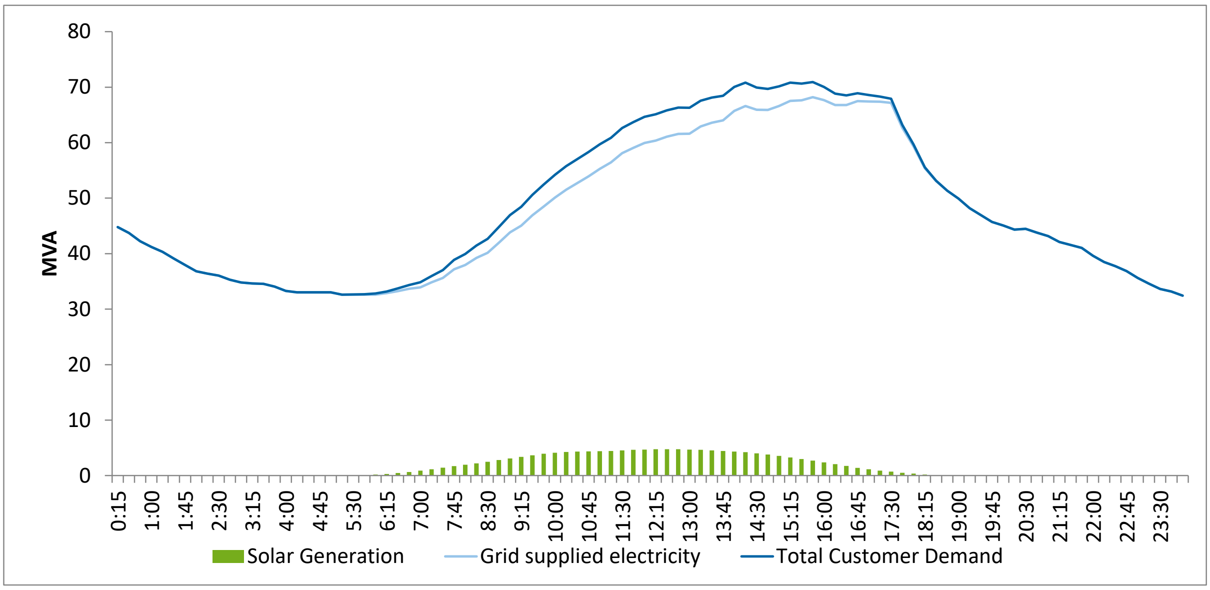


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Burwood ZS has typically occurred in summer between 12:00 and 5:00pm AEDT.

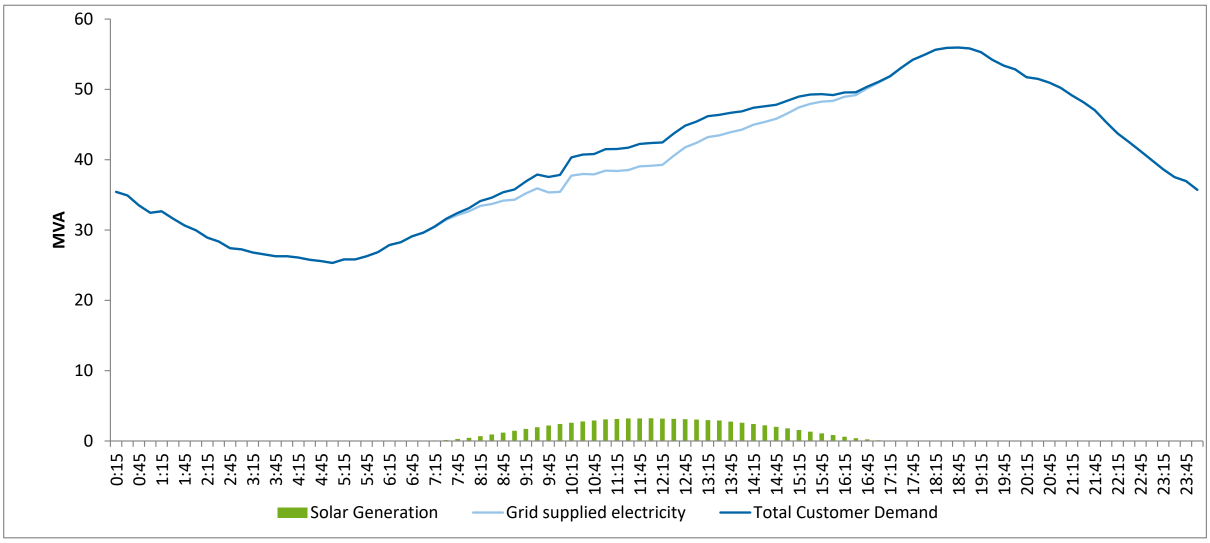
There is a total Solar PV capacity of approximately 7.23 MW connected to Burwood ZS. At the peak time of 12:45pm AEDT on 29 November 2020, these PV systems are estimated to have been generating 4.76 MW. Figure 2 below shows the load trace on this day including the contribution from customer solar power systems.

Figure 2: Summer peak day demand profile and PV contribution at Burwood ZS on 29 November 2020



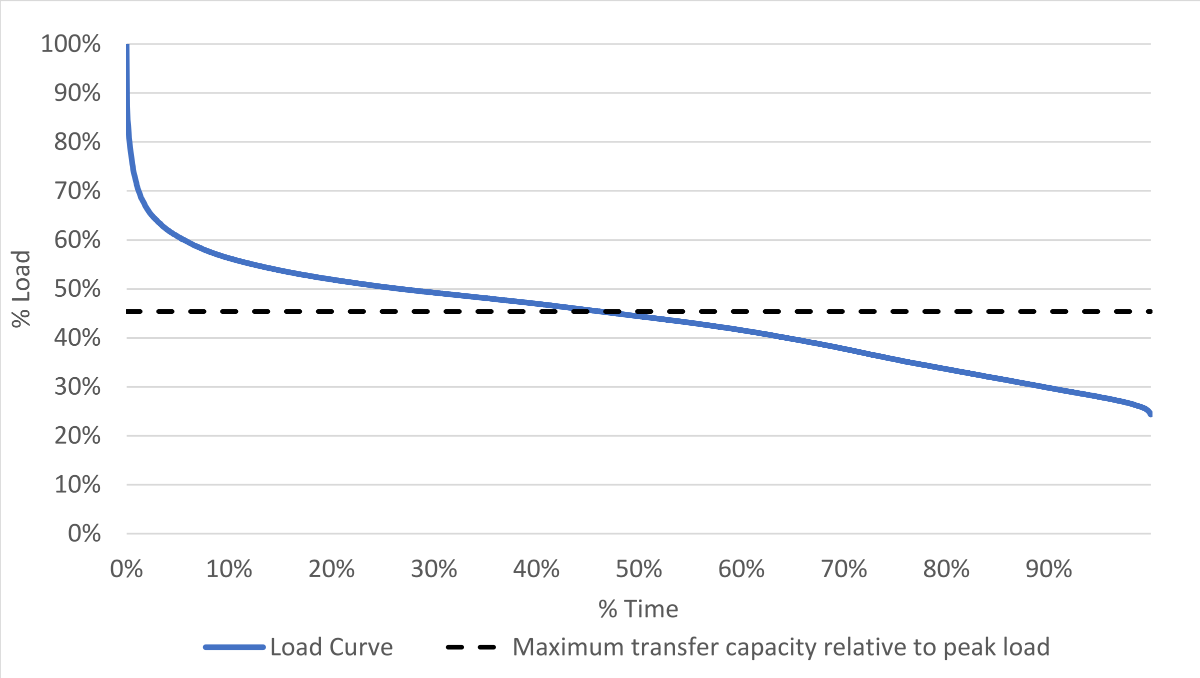
Over the past 7 years, the time of winter peak has typically occurred between 3:30 pm and 5:30pm AEST. At the peak time of 12:00pm AEST on 9 August 2020, the estimated generation from PV systems is 3.22 MW. **Error! Reference source not found.** below shows the load profile for the peak demand day 9 August 2020 including the contribution from customer installed solar power systems.

Figure 3: Winter peak day demand profile and PV contribution at Burwood on 9 August 2020



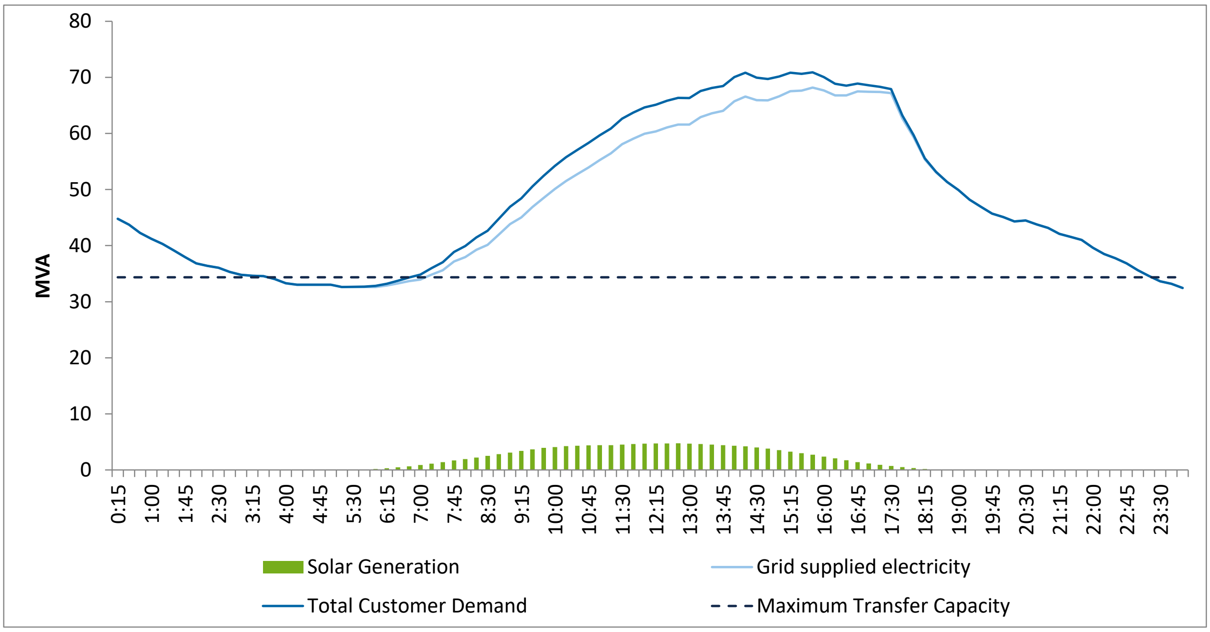
Burwood ZS currently has a load transfer capacity of 34.35.4 MVA or about 45.44% of the weather corrected maximum 2020/21 summer demand at 50 POE and 60.5% of the weather corrected maximum for winter 2020. The load duration curve including the load transfer capacity is shown in Figure 4.

Figure 4: Burwood load duration curve



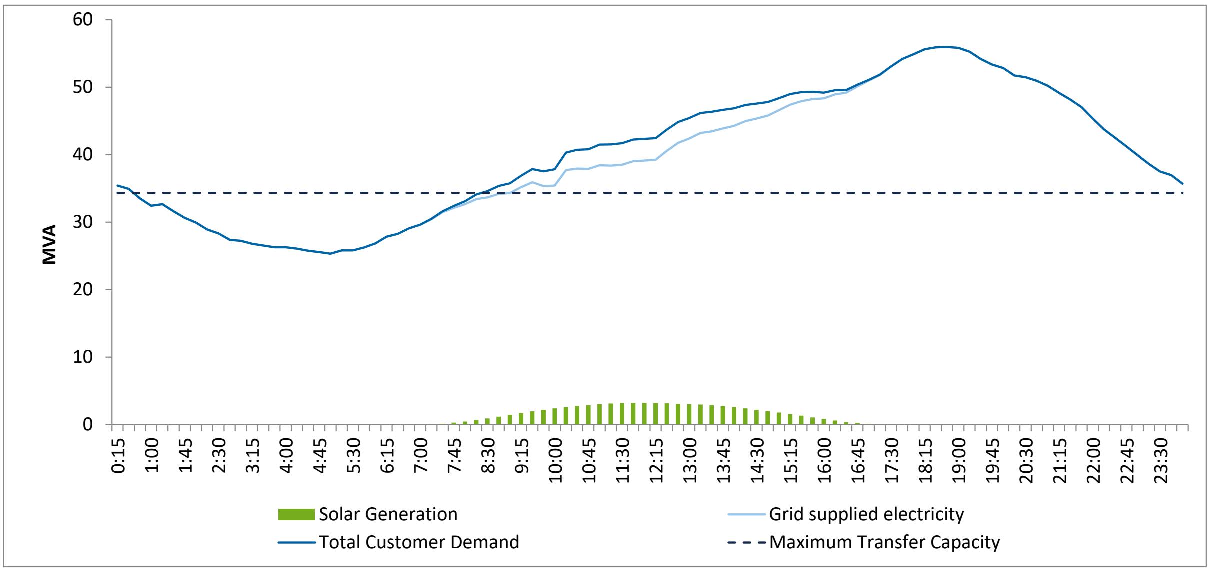
In the event of a network outage on the summer maximum demand day and following realisation of the maximum transfer capacity through network switching, there is a maximum shortfall of around 33.84 MVA. The shortfall would occur for most of the day as seen in Figure 5 below.

Figure 5: Summer maximum demand profile at Burwood on 29 November 2020



Similarly, for the winter peak demand day, the shortfall would also be for most of the day after realising the maximum load transfer capacity. The maximum shortfall would be around 21.91 MVA and there would be a shortfall for most of the day (see Figure 6).

Figure 6: Winter maximum demand profile at Burwood on 9 August 2020



2.3 Customer characteristics

Burwood ZS serve a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2021/22 period are as follows:

Table 1: Burwood customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	20,735	2,181	183	23,099
% of Customers	89.8%	9.4%	0.8%	
Annual Consumption (MWh)	100,642	44,510	127,761	272,932
% of Annual Consumption	36.9%	16.3%	46.8%	
Number of Solar Customers	1,371	51	22	1,444
% of Solar Customers	6.6%	2.3%	12.0%	
Average Annual Consumption (MWh)	5	20	650	11

3 Proposed preferred network option

This section provides details of credible options that Ausgrid has identified as part of its network planning activities to date. All costs in this section are in real $2022/23, unless otherwise stated.

Table 2: Summary of the credible options considered

Overview	Key components	Estimated capital cost (including decommissioning costs)
Option 1 – Like-for-like replacement of SCFF sections of feeders 923 and 924 in existing route using modern equivalent technology	The work for option 1 involves the replacement of approximately 1.6 kilometres of underground SCFF cable along the existing route configuration. This would require: • works at Mason Park STSS, Strathfield TP and Burwood ZS to facilitate the new 132kV feeder connection; • installation of two 132kV XLPE feeders of approximately 1.6km from Strathfield TP to Burwood ZS, with a proposed firm rating of 230MVA; • metering, control and protection communication upgrades at both ends; and • decommissioning of the existing SCFF feeder between Strathfield TP and Burwood ZS.	$15.3 million
Option 2 – Replacement of SCFF sections of feeders 923 and 924 in alternative route using modern equivalent technology	The works for the option 2 include: • construction of 1.5 km of dual circuit ductline between Lloyd George Avenue, Burwood and Ismay Reserve, Strathfield; • construction of one joint bay mid-way along the proposed route; • installation of new XLPE cables along the dual circuit ductline; • relocation of 11kV feeder along Concord Rd and recovery of redundant 33kV cables; • installation of two new steel UGOH (underground to overhead) poles in the Ismay Reserve; • removal of 230m section of dual circuit overhead wires and poles between Paramatta Rd and Strathfield TP; • protection and communication upgrades at Burwood ZS and Mason Park STSS; • decommissioning of the Strathfield TP at Columbia Lane, Strathfield and preparing the site for divestment; and • decommissioning existing SCFF sections of feeders 923 and 924.	$13.2 million

3.1 Options considered but not progressed

Ausgrid has considered one additional network option involving decommissioning the existing Burwood ZS and associated feeders 923 and 924 supplying the Burwood ZS. The costs for this option were found to be materially higher than Options 1 and 2, due to the extensive 11kV feeder installation works required to transfer the load to adjacent zone substations, as well as network augmentations at these sites.

3.2 Three different scenarios have been modelled to deal with uncertainty

Ausgrid has assessed three alternative future scenarios for this RIT-D – namely a:

- 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 the credible option;
- central scenario – the central 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 3: Summary of the three scenarios investigated

Variable	Scenario 1 – central	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand[1]	POE50 Step Change	Minimum POE50 demand across AEMO scenarios	POE10 Step Change
VCR	\$55.51/kWh[2]	\$38.86/kWh 30 per cent lower than the central estimate	\$72.17/kWh 30 per cent higher than the central estimate
Capital costs[3]	Base line capital cost estimate	115 per cent of capital cost estimate	85 per cent of capital cost estimate
Unplanned corrective maintenance	Base line estimate	70 per cent of base line estimate	130 per cent of base line estimate
Environmental risk costs	Base line estimate	70 per cent of base line estimate	130 per cent of base line estimate
Discount Rate	3.44%	5.50%	2.34%

Ausgrid has developed demand forecasts consistent with AEMO's 2022 Integrated System Plan (ISP) forecasts for future demand growth, with AEMO's POE50 forecasts for the 'Step Change' assumed in the central scenario.

Ausgrid considers that the central scenario is the most likely, since it is based primarily on a set of expected/central assumptions. Ausgrid has therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with symmetric 25 per cent each. However, Ausgrid notes that the identification of the preferred option is the same across all three scenarios, i.e. the result is insensitive to the assumed scenario weights.

[1] The demand forecasts align with those used by AEMO in the 2022 ISP.

[2] Derived from the AER 2019 estimates, inflated by the CPI and load weighted to reflect the site-specific VCR at the Burwood ZS. See Appendix D for full calculation.

[3] The variation in capital cost sensitivity also affects planned maintenance since this cost is a proportion of capital expenditure. Decommissioning costs associated with each option (which are capitalised) are also included in this sensitivity.

3.3 Preferred option at this stage

Ausgrid proposes Option 2 as the preferred option that satisfies the RIT-D. This option involves the commissioning of new underground sections of feeders 923 and 924, using XLPE technology between Burwood ZS and Ismay Reserve, as well as the decommissioning of the Strathfield TP and removal of 230 metres of overhead lines.

Option 2 has been determined to be the preferred option as it results in the highest net present value in the NPV modelling assessment across all scenarios, largely due to the lower capital costs associated with this option.

The estimated capital cost of this option is $15.3 million, including decommissioning costs of approximately $600k. Ausgrid assumes that the necessary construction to install the new feeders will commence in 2022/23 following completion of the regulatory process, for commissioning in 2024/25. Once the new installation is complete, operating costs are expected to be approximately $13k per annum (0.1 per cent of capital expenditure per annum).

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

4 Assessment of SAPS and non-network solutions

4.1 Required demand management characteristics

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 2024/25 for deferral of the network investment.

4.2 Available demand management funds

To identify the available funds for a possible demand management solution, Net Present Value (NPV) analysis was carried out and the net NPV for the network option is compared against the net NPV of deferral scenarios.

Table 4 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years.

Table 4: Required demand reduction and available funds at Burwood

Required peak demand reduction	Available demand management funds ($)		
	1 Yr deferral	2 Yr deferral	3 Yr deferral
20MVA*	$390k	$680k	$900k

*To be viable, DM solutions must materially reduce demand at times other than at peak due to the replacement driver. Available funds have been calculated accordingly.

- For a 1-year deferral, around 20MVA of demand reduction is required in 2024/25 with total available demand management funds of $390k, which is equivalent to $19/kVA/year,
- For 2-year deferral, 20MVA of demand reduction in 2024/25 and 2025/26 with total available demand management funds of $680k, which is equivalent to $17/kVA/year, and
- For 3-year deferral, 3MVA of demand reduction is required in 2024/25, 2025/26 and 2026/27 with total available demand management funds of $900k, equivalent to $15/kVA/year

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 4.3 below.

4.3 Options considered

Ausgrid has considered Stand Alone Power Systems (SAPS) and other demand management solutions to determine their commercial and technical feasibility to assist with the identified need for Burwood ZS. Each of the solutions considered is summarised below using the following approach:

- SAPS are considered separately since they have the technical potential to provide a complete solution, subject to financial constraints,
- If SAPS are not viable, a build-up approach is used to assess the feasibility of stacking other solutions together such as power factor correction, demand response, customer solar power systems, customer energy efficiency, battery storage and dispatchable generators to form a complete demand management solution.

4.3.1 Stand Alone Power Systems (SAPS)

SAPS self-generate, store and supply electricity to connected customers that are physically disconnected to the wider electricity grid. Typical SAPS are made up of solar panels, a battery storage system and a back-up diesel generator.

Ausgrid is currently trialling SAPS with selected customers living in fringe-of-grid areas of Ausgrid's network[4]. The program aims to explore how SAPS can provide an alternative electricity supply solution that improves reliability and safety of our service to remote and rural customers, as well as being sustainable and cost-effective.

Ausgrid's experience with proposals from SAPS providers during the trial has provided insights on the cost of SAPS. On average it would cost $50k-100k or more to supply a typical residential customer (based on their annual energy usage) using a SAPS. Assuming a mid-point SAPS cost of $75k each, the number of customers that Ausgrid would be able to supply via SAPS using all the available funds would only be around 12 customers or less. This is not sufficient to reduce, defer or postpone the proposed preferred network solution.

Since SAPS are not viable, the following sections describe a build-up approach to assess the feasibility of building a complete demand management solution using other means of reducing demand.

4.3.2 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 a mix of a temporary reduction in customer load and/or 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 200 hours. The demand response required for the top 200 hours of demand is 2MVA. 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.

Assuming that 2MW in demand response was available in the area and could be acquired for an estimated $75-125 per kVA per year for 12 months availability, approximately $75-125k would be required each year. The cost of this solution represents:

- $150-250k (38% to 64%) of the available funds in the 1-year deferral case ($390k available funds),
- $300-500k (44% to 74%) of the available funds in the 2-year deferral case ($680k available funds), and
- $450-750k (50% to 83%) of the available funds in the 3-year deferral case ($900k available funds).

Additional solutions beyond Demand Response are needed to address the requirement of demand reductions outside of peak demand periods. Further details of other demand management solutions and and assessment of their viability is provided below.

4.3.3 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 at a low cost. Analysis of customer interval data indicates a commercial peak demand reduction potential of less than 70kVA at Burwood ZS. At a projected demand management cost of about $25-50 per kVA, or a total cost of around $2-4k, the solutions appear cost effective. However, this solution would contribute only 0.4% of the required 20MVA demand reduction.

Other DM solutions would need to be considered cost-effective to enable customer power factor correction to form part of a DM solutions mix. Further details of other demand management solutions and and assessment of their viability is provided below.

---

[4] https://www.ausgrid.com.au/In-your-community/Stand-Alone-Power-Systems

4.3.4 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, which can alleviate the impact of overload conditions. Analysis of interval data for Burwood ZS shows that while solar generation is partially coincident with the energy shortfall, it offers no reduction in load during non-solar 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. As solar power system generation is subject to hourly, seasonal and cloud cover variation (ie the solar "bell curve"), an example of 1 MW solar array is estimated to generate up to 1.4GWh annually, which translates into roughly 33% of the annual energy compared to a load reduction of 1 MW at peak and proportional reductions at other times of the year.

While customer solar power systems would address a material amount of the energy reduction requirement compared to power factor correction or demand response, the funding constraints and fixed times when solar is able to reduce demand mean that only a limited quantity of solar could be afforded and that all remaining funds should not be entirely spent on solar. Assuming that 2 MW of additional solar could be procured for around $500k, the running total cost of demand management solutions from demand response, power factor correction and customer solar power systems would be as follows:

- 1-year deferral: Total cost $650-750k comprising 2MW of demand response $150-250k for 1 year, 70 kVA of power factor correction: $2-4k and 2 MW of customer solar systems: $500k which exceeds the available funds under this scenario of $390k by between 67-92%. No further funds are available for other solutions that can reduce demand outside of solar generation hours, noting that there remains a significant demand and energy shortfall considering the total requirement of 20MVA at peak shown in Table 4 above.
- 2-year deferral: Total cost $800k-1.0M comprising 2MW of demand response $300-500k for 2 years, 70 kVA of power factor correction: $2-4k and 2 MW of customer solar systems: $500k which exceeds the available funds under this scenario of $680k by between 18-47%. No further funds are available for other solutions that can reduce demand outside of solar generation hours, noting that there remains a significant demand and energy shortfall considering the total requirement of 20MVA at peak shown in Table 4 above.
- 3-year deferral: Total cost $950-1.25M comprising 2MW of demand response $450-750k for 3 years, 70 kVA of power factor correction: $2-4k and 2 MW of customer solar systems: $500k which exceeds the available funds under this scenario of $900k by between 6-39%. No further funds are available for other solutions that can reduce demand outside of solar generation hours, noting that there remains a significant demand and energy shortfall considering the total requirement of 20MVA at peak shown in Table 4 above.

From the above analysis the available funds for demand management falls materially short of being able to address a sufficient quantum of both the peak demand and energy requirement to enable deferral of the proposed network solution.

4.3.5 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.

Following the build-up approach up to Section 4.3.4 above, there are no funds available for this solution to be considered part of a cost-effective alternative.

4.3.6 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 small component of the energy shortfall.

There are insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.7 Standby generation

Standby generation, such as diesel generators, are a flexible form of network support which are leased and connected to the relevant part of the network experiencing a constraint. Typical cost structures for leasing standby generators comprise of weekly hire costs, usage costs (charged per hour when the generator is running) and fuel costs. Due to the nature of a major equipment outage that may be experienced at Burwood ZS and how a wide area may be impacted, it is likely that a standby generator would need to be connected at 11kV, requiring the leasing of a step-up transformer in addition to the generator.

Since a major equipment outage could occur at any time, a standby generator utilised as part of a demand management solution would need to be available and therefore leased for 52 weeks each year. Typical leasing costs might be upwards of $300k per year (or at least $900k for 3 years) per 1 MVA of standby generation capacity which does not account for other costs necessary to establish a standby generator such as usage, fuel and a step-up transformer.

There are insufficient funds available for standby generation and even when considering using the entire available demand management funds for standby generation only, $390-$900k for 1 to 3 years, standby generators are not considered cost-effective in this instance.

5 Conclusion

Based on the demand management options considered in Section 4, 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, an Options Screening Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.