Addressing reliability requirements in the Milperra load area

NOTICE ON SCREENING FOR SAPS AND NON-NETWORK OPTIONS

01 May 2023

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1 Introduction

Milperra Zone Substation (ZS) is in the Canterbury/Bankstown network area and was commissioned in 1966. It is supplied by two 132kV underground feeders from Sydney South Bulk Supply Point (BSP) via Revesby ZS. It is equipped with one 11kV compound insulated switchboard and 11kV air insulated switchboard in a double bus arrangement. It currently supplies approximately 9,500 customers including major customers such as Bankstown-Lidcombe hospital, Western Sydney region TAFE and Sydney Water Corporation.

The original 1966 compound-insulated switchboards are deteriorating due to their age, and are resulting in condition, reliability and safety concerns. Ausgrid has initiated this RIT-D to replace the 11kV switchgear at Milperra ZS in order to identify a preferred option that would address the risk that the existing ageing 11kV compound insulated switchgear poses, and 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 and 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 Final Project Assessment Report (DPAR).

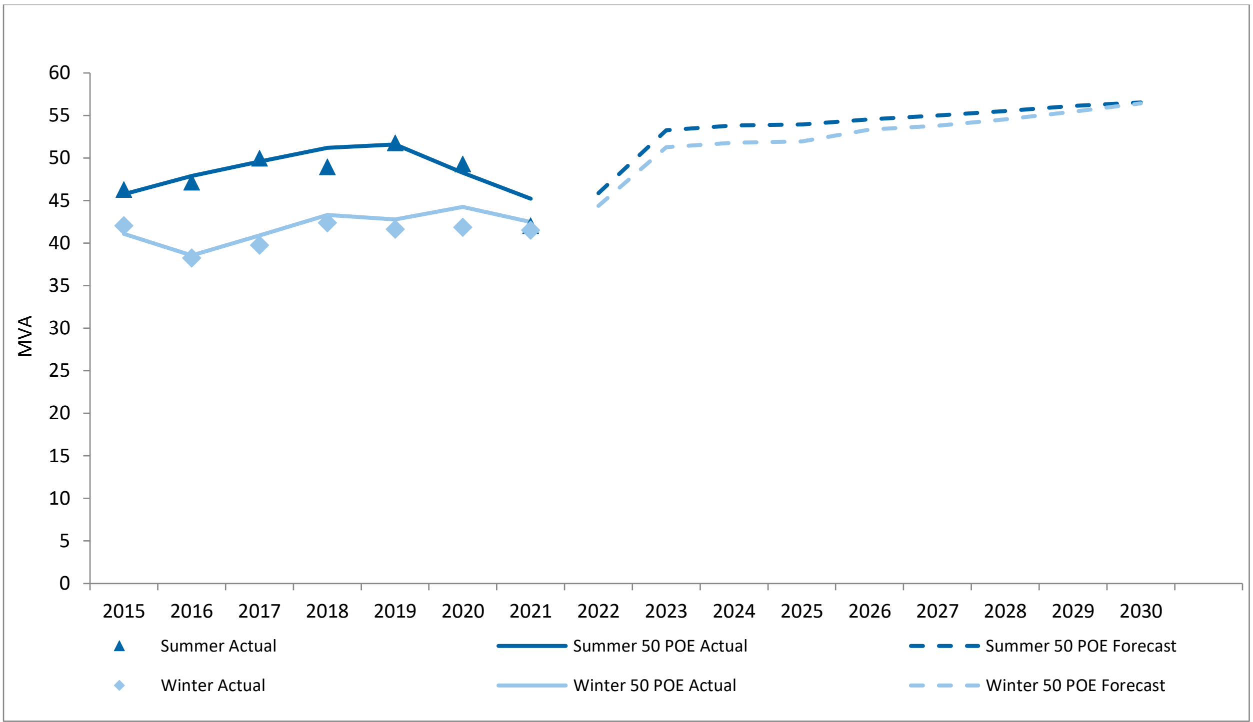
2 Forecast load and capacity

2.1 Demand forecast

Figure 1 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 Milperra ZS.

Milperra ZS has a total capacity of 123.2 MVA and a firm capacity of 61.2 MVA. In 2020/21, the maximum demand on the ZS was 42 MVA at 3:45pm AEDT on 17 December 2020. The weather corrected demand at the 50 POE level was 45.2 MVA. The power factor at the time of summer maximum demand was 0.97.

Figure 1: Demand forecast at Milperra

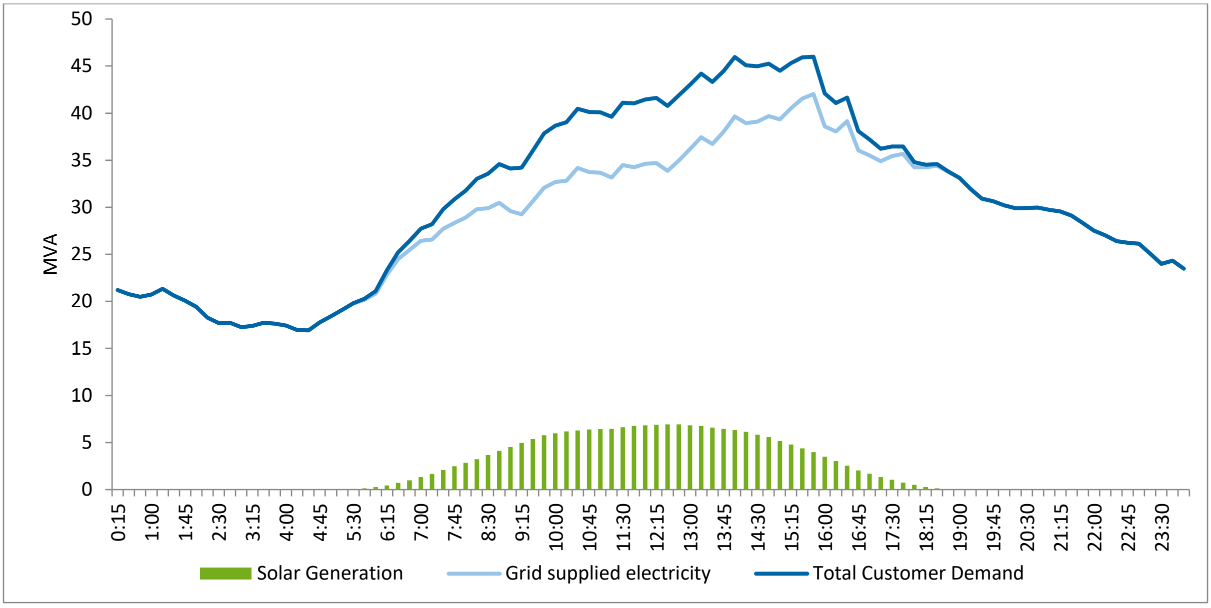


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Milperra ZS has typically occurred in summer between 1:00pm and 4:30pm AEDT.

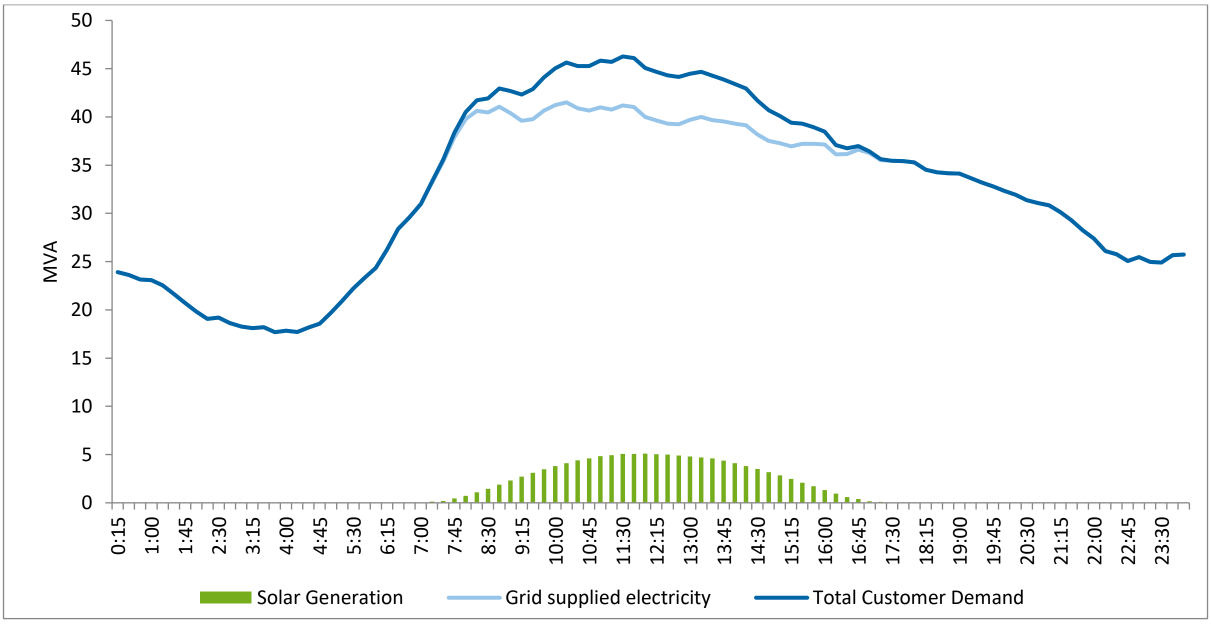
There is a total Solar PV capacity of approximately 10.5 MW connected to Milperra ZS. At the peak time of 3:45pm AEDT on 17 December 2020, these PV systems are estimated to have been generating 4 MW. Figure 2 shows the load trace on this day including the contribution from customer solar power systems.

Figure 2: Summer peak day demand profile and PV contribution at Milperra on 17 December 2020



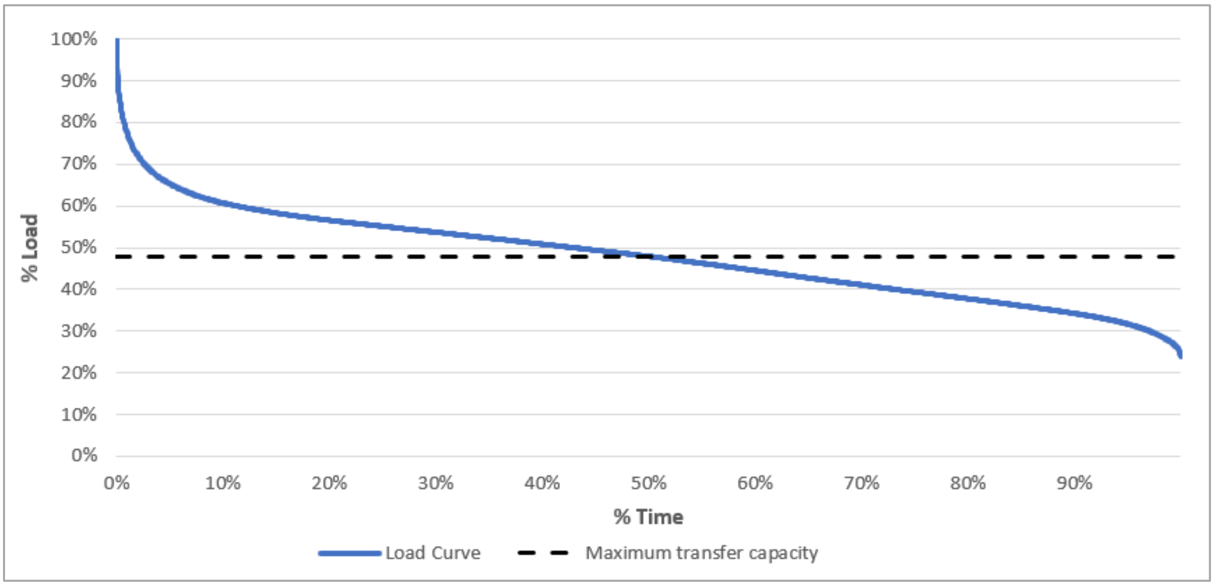
Over the past 7 years, the time of winter peak has typically occurred between 8:15 am and 12:00pm AEST. At the peak time of 10:15am AEST on 10 June 2021, the estimated generation from PV systems is 4.11 MW. Figure 3 below shows the load profile for the peak demand day 10 June 2021 including the contribution from customer installed solar power systems.

Figure 3: Winter peak day demand profile and PV contribution at Milperra on 10 June 2021



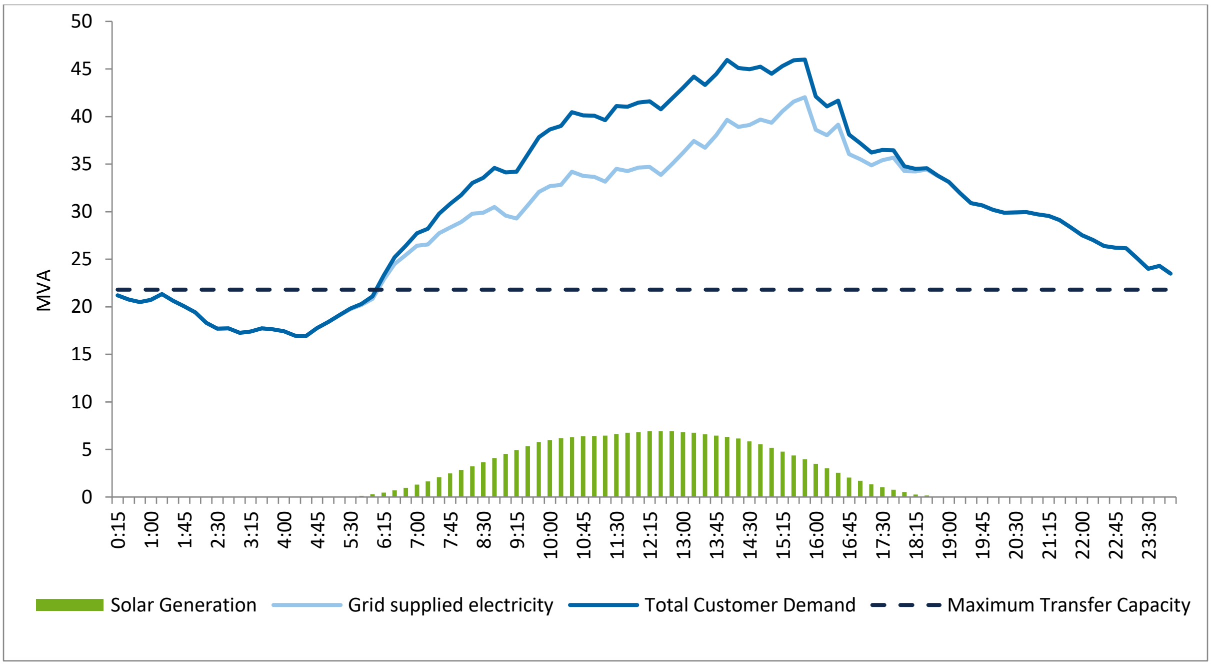
Milperra ZS has a load transfer capacity of 21.8 MVA or about 48% of the weather corrected POE50 peak of 45.2 MVA for summer of 2020/21. The load duration curve including the load transfer capacity is shown in Figure 4.

Figure 4: Milperra load duration curve



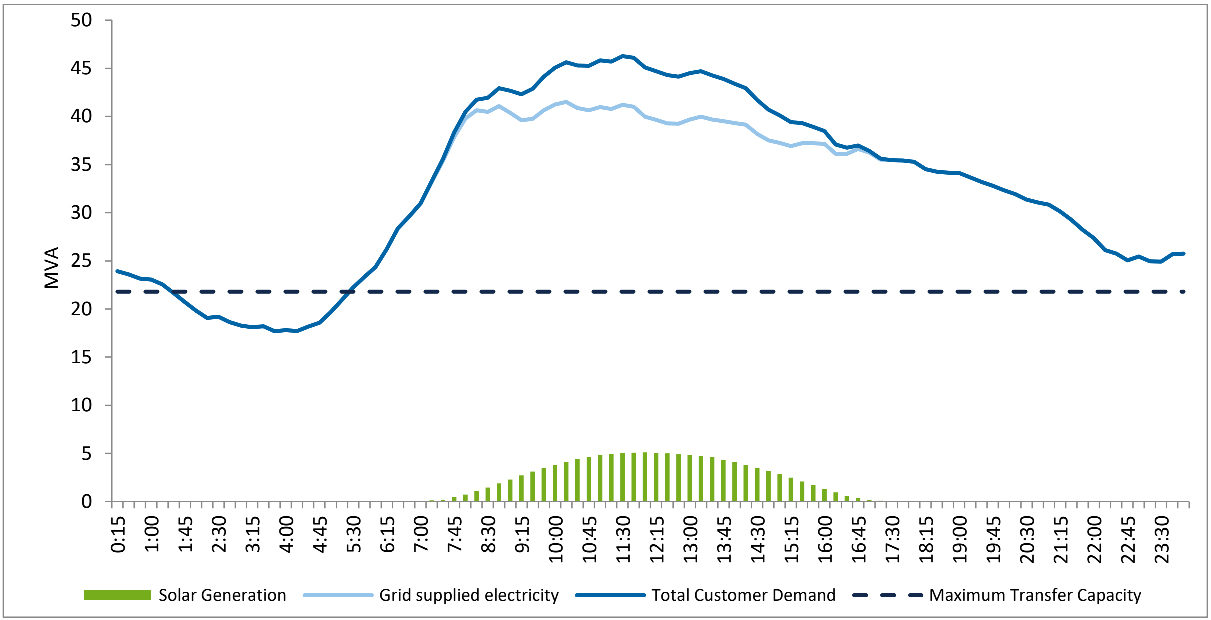
In the event of a network outage on the summer maximum demand day and following realisation of the maximum transfer capacity through network switching, there is a maximum shortfall of around 20.2 MVA when compared to the actual peak (non-weather corrected). The shortfall would occur for most of the day as seen in Figure 5 below.

Figure 5: Summer maximum demand profile at Milperra on 17 December 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 as seen in Figure 6. The maximum shortfall would be around 19.7 MVA when compared to actual peak (non-weather corrected).

Figure 6: Winter peak day demand profile and PV contribution at Milperra on 10 June 2021



2.3 Customer characteristics

Milperra ZSs 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: Milperra customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	8,094	1,326	105	9,525
% of Customers	85%	13.9%	1.1%	
Annual Consumption (MWh)	53,940	27,219	95,609	176,767
% of Annual Consumption	30.5%	15.4%	54.1%	
Number of Solar Customers	1,424	110	19	1,553
% of Customers with Solar	17.6%	8.3%	42.8%	
Average Annual Consumption (MWh)	7	21	911	19

About 84% of residential customers live in detached homes with an average usage of about 7.5 MWh per year. Households living in apartments, villa, townhouses and flats have an average usage of about 4.6 MWh per year.

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 – Replacement of the 11kV switchgear using an extension of the existing switchroom	• Extension of the current switchroom building to accommodate the replacement 11 kV switchgear • Installation of a new 11 kV switchboard including four sections of single bus switchgear and 21x11 kV circuit breakers • Installation of 11 kV connections to transfer the load from the existing 11 kV feeders to the new switchboard • Secondary system upgrades • Decommissioning of the 11 kV compound insulated switchboard from the site	$13.2 million

Ausgrid also considered an additional option that has not been progressed. The table below summarises Ausgrid's consideration and position on each of these potential options.

Table 3: Network options considered but not progressed

Option	Description	Reason why option was not progressed
Establish a new substation and retire Milperra ZS	Establish a new substation in the load area and retire Milperra ZS	Costs are substantially higher than the credible option with no corresponding increase in benefits. The option also requires a longer timeframe due to the need to construct a new ZS on a suitable site. This option is therefore not considered to be economically feasible.
Transfer the 11 kV load to adjacent zone substations	Transfer load to adjacent zone substations, mainly Revesby ZS, and decommission the compound insulated switchgear at Milperra ZS.	Costs are substantially higher than the credible option with no corresponding increase in benefits. This option is therefore not considered to be economically feasible.
Replace the 11 kV switchgear by utilising a mobile	Installation of a MER arrangement capable to accommodate and	A MER is designed to accommodate 11 circuit breakers, while this RIT-D is looking to address 21 circuit breakers. This option would therefore require

equipment room (MER)	arrangement of 21x11kV circuit breakers within the site and decommission the compound insulated switchgear at Milperra ZS.	two MERs or a re-design that, along with the additional time required for design work, mean that this option is expected to be significantly more expensive than Option 1 without providing any additional benefits. This option is therefore not considered to be economically feasible.
Including the air insulated switchboard in the scope of the preferred option	Replacing the air insulated 11 kV switchboard at the same time	The air insulated switchboard is in better condition than the compound insulated switchboards and is not expected to require replacement for another 15-20 years. There are also not expected to be any material operational cost savings/efficiencies with doing both works at once as they are largely discrete tasks. This work is therefore not required to meet the identified need and so is considered not technically feasible.

Table 4: Summary of the three scenarios investigated

Variable	Scenario 1 – central	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand	POE50 Step Change	Minimum POE50 demand across AEMO ISP scenarios	POE10 Step Change
Safety and health risk costs	Central estimate	70 per cent of base line estimate	130 per cent of base line estimate
Avoided reactive maintenance costs	Central estimate	70 per cent of base line estimate	130 per cent of base line estimate
VCR	$57.80/kWh across all scenarios		
Discount Rate	3.44% across all scenarios		

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

3.1 Preferred option at this stage

Ausgrid considers that Option 1 is the preferred option that satisfies the RIT-D. It involves the replacement of the existing 11 kV double bus switchgear at Milperra ZS with modern equivalent switchgear in an extension to the existing switchroom.

The estimated capital cost of this option is $13.2 million which includes decommissioning costs of approximately $0.7 million.

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

4 Assessment of SAPS and non-network solutions

4.1 Required demand management characteristics

As noted in Section 2, an outage originating from the 11kV switchgear may result in significant supply shortfall at Milperra ZS.

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 2025/26 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 5 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years.

Table 5: Required demand reduction and available funds at Milperra

Required peak demand reduction	Available demand management funds ($)		
	1 Yr deferral	2 Yr deferral	3 Yr deferral
12MVA*	$405k	$735k	$990k

*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 12MVA of demand reduction is required in 2025/26 with total available demand management funds of $405k, which is equivalent to $34/kVA/year,
- For 2-year deferral, 12MVA of demand reduction in 2025/26 and 2026/27 with total available demand management funds of $735k, which is equivalent to $31/kVA/year, and
- For 3-year deferral, 12MVA of demand reduction is required in 2025/26, 2026/27 and 2027/28 with total available demand management funds of $990k, equivalent to $28/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 Milperra ZS. Each of the solutions considered is summarised below.

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[1]. 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 5 to 13 customers. 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. 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 6MVA of demand response was available for an estimated $75-125 per kVA per year for 12 months availability, the cost of this solution represents:

- $450k-750k in the 1-year deferral case (111% to 185% of available funds)
- $900k-1.5m in the 2-year deferral case (122% to 204% of the available funds)
- $1.35m-2.25m in the 3-year deferral case (136% to 227% of the available funds)

In all cases the cost of 6MVA of demand response exceeds the available funds while only addressing 50% of the required demand reduction. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

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 approximately 225kVA at Milperra ZS. At a projected demand management cost of about $25-50 per kVA, or a total cost of around $5-12k, the solutions appear cost effective. However, this solution would contribute less than 2% of the required 12MVA 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 assessment of their viability is provided below.

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

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

can alleviate the impact of overload conditions. Analysis of interval data for Milperra 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 kW would, for example, incentivise an additional 1 MW of customer solar power systems requiring a total customer incentive payment of about $250k. Approximately $3m would be required in order to achieve the required demand reduction of 12 MW, which exceeds the available funds. We therefore consider there is insufficient funds available for this solution to be part of a cost-effective alternative.

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. Customer energy efficiency improvements as a demand management solution may help to alleviate energy shortfalls that occur for a substantial number of hours of the year, as shown in section 2.2.

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 12MVA of reduction at an approximate cost between $2.4m-$6m, which far exceeds the available funds. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective alternative.

4.3.6 Large customer energy storage

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 MW, 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 demand reduction. 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 Milperra 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.

Considering 1MVA standby generation would only address a small portion of the required demand reduction while exceeding most of the available budget, standby generators are not considered cost-effective in this instance.

4.3.8 Combining demand management solutions

There is no demand management solution mix that could meet the required demand reductions with the funds that are available. Apart from power factor correction, the costs of all demand management solutions considered exceed the $/kVA available for this project. Power factor solution alone is insufficient to adderess the required demand reduction.

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.