Addressing reliability requirements in the Mascot load area

NOTICE ON SCREENING FOR SAPS AND NON-NETWORK OPTIONS

18 August 2023

Ausgrid

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Addressing reliability requirements in the Mascot load area

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Contents

1 Introduction

Mascot 33/11kV Zone Substation (ZS) was commissioned in 1946 and is located in the Eastern Suburbs area. It supplies 6,103 residential customers and 1,034 industrial/commercial customers, including Qantas Corporate Precinct and Equinix Data Centre.

Mascot ZS comprises three groups of 11kV compound insulated switchgear and two groups of 11kV air insulated switchgear configured in a double bus arrangement. Mascot ZS is supplied by six 33kV cables from Bunnerong North Subtransmission Station (STS).

There are increasing reliability and safety risks associated with the aging compound insulated 11kV switchgear at Mascot ZS. The three groups of compound-insulated switchgear consist of Bulk Oil Circuit Breakers (OCBs), which have been in service for over 75 years and are approaching the end of their serviceable lives.

If no corrective action is taken, our planning studies (based on predictive failure modelling) indicate an increasing amount of expected unserved energy (EUE) at Mascot ZS, as well as increasing safety risks and reactive maintenance costs associated with having to repair and restore service in the event of equipment failure. Substantial market benefits are expected to arise from taking action to avoid this EUE. Further, we expect that reliability performance standards would be put at risk if action is not taken, based on the amount of EUE calculated at Mascot ZS.

In September 2019, Ausgrid commenced a RIT-D through publishing a non-network options report (NNOR) to investigate the potential for demand management solutions to alleviate constraints associated with aging switchgear condition issues at Mascot ZS. Ausgrid received several submissions from interested parties, however, due to a change to the preferred network option to one that was much lower in capital cost shortly after receiving the NNOR submissions, the business case for non-network options became no longer viable. At the time, Ausgrid was able to reduce the load at Mascot ZS by transferring loads to the nearby Green Square ZS. As a result, the peak load at Mascot was reduced from 52MVA in summer 2018/19 to 35MVA in summer 2020/21. Whilst these works were conceived as a risk mitigation measure capable to defer the construction of a new zone substation, which was the preferred network solution in 2019, it was identified that such load transfers could become permanent due to lower demand forecasts, bringing an opportunity to consider other network solutions. Therefore, the RIT-D that commenced in 2019 did not progress further.

Ausgrid is therefore undertaking a Regulatory Investment Test for Distribution (RIT-D) to assess options for addressing the risk that the existing ageing 11kV compound insulated switchgear poses (not for the entire Mascot ZS as was identified in 2019), 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 options form 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).

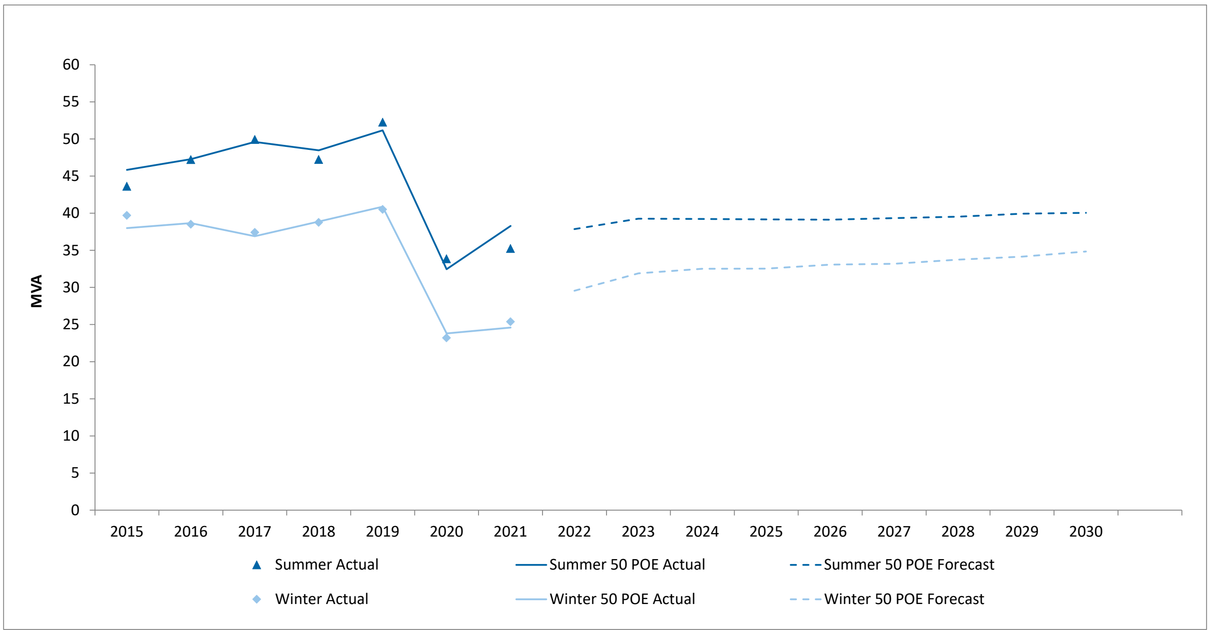
2 Forecast load and capacity

2.1 Demand forecast

Figure 1 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 Mascot ZS.

Mascot ZS has a total capacity of 103.6 MVA and a firm capacity of 78.4 MVA. In 2020/21, the maximum demand on the ZS was 35.2 MVA at 10:15pm AEDT on 18 December 2020. The weather corrected demand at the 50 POE level was 38.3 MVA. The power factor at the time of summer maximum demand was 0.93.

Figure 1: Demand forecast at Mascot

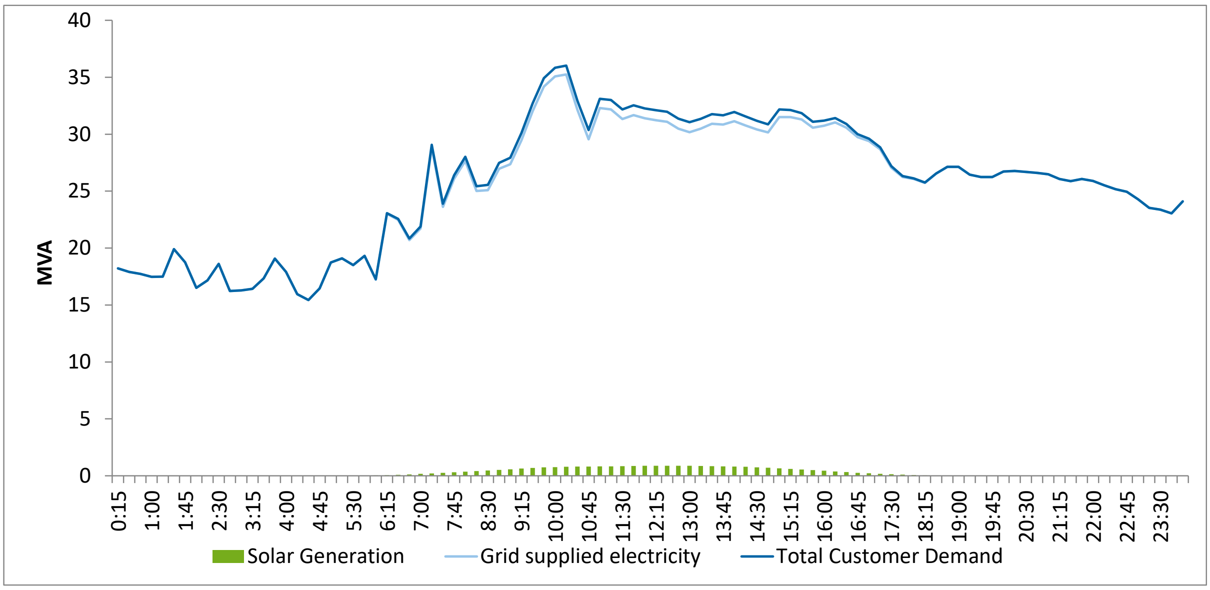


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Mascot ZS has typically occurred in summer between 10:15am and 4:00pm AEDT.

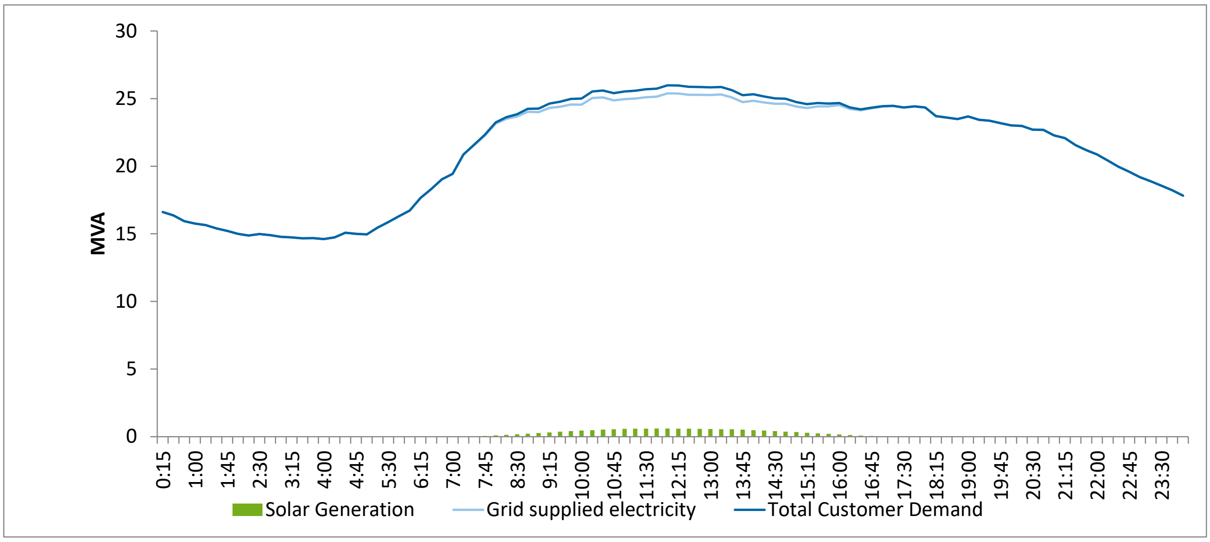
There is a total Solar PV capacity of approximately 2.0 MW connected to Mascot ZS. At the peak time of 10:15am AEDT on 18 December 2020, these PV systems are estimated to have been generating 0.88 MW. Figure 2 shows the load trace on this day including the contribution from customer solar power systems.

Figure 2: Summer peak day demand profile and PV contribution at Mascot on 18 December 2020



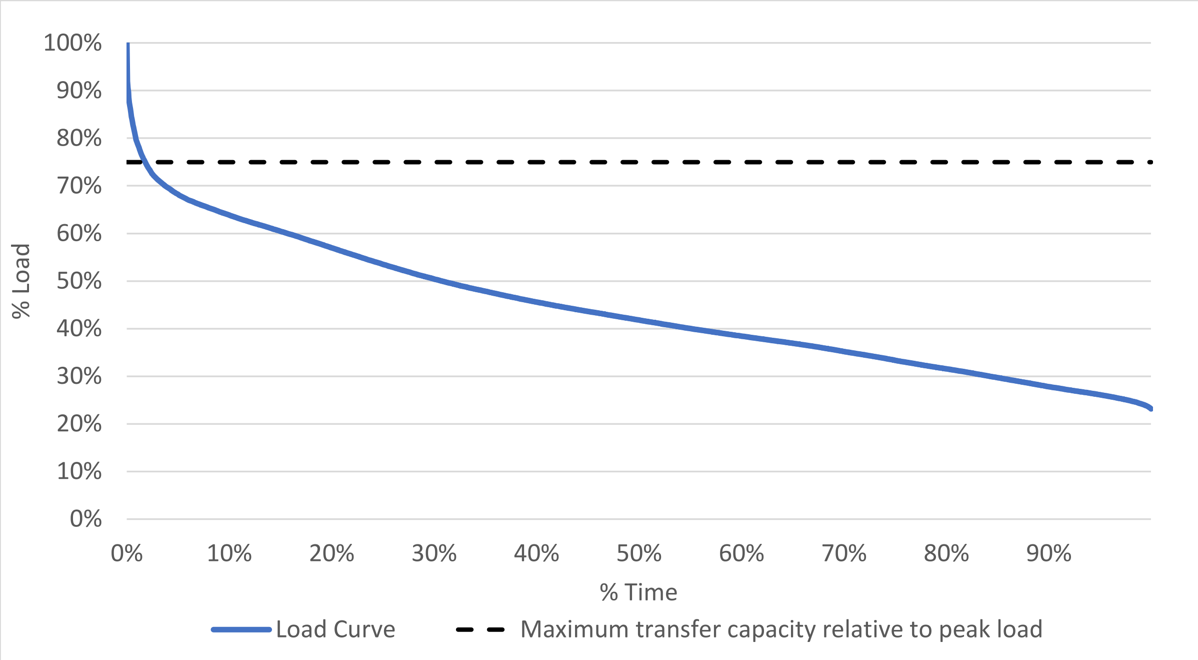
Over the past 7 years, the time of winter peak has typically occurred between 8:15 am and 12:15pm AEST. At the peak time of 12:00am AEST on 10 June 2021, the estimated generation from PV systems is 0.6 MW. Figure 3 below shows the load profile for the peak demand day 10 June 2021 including the contribution from customer installed solar power systems.

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



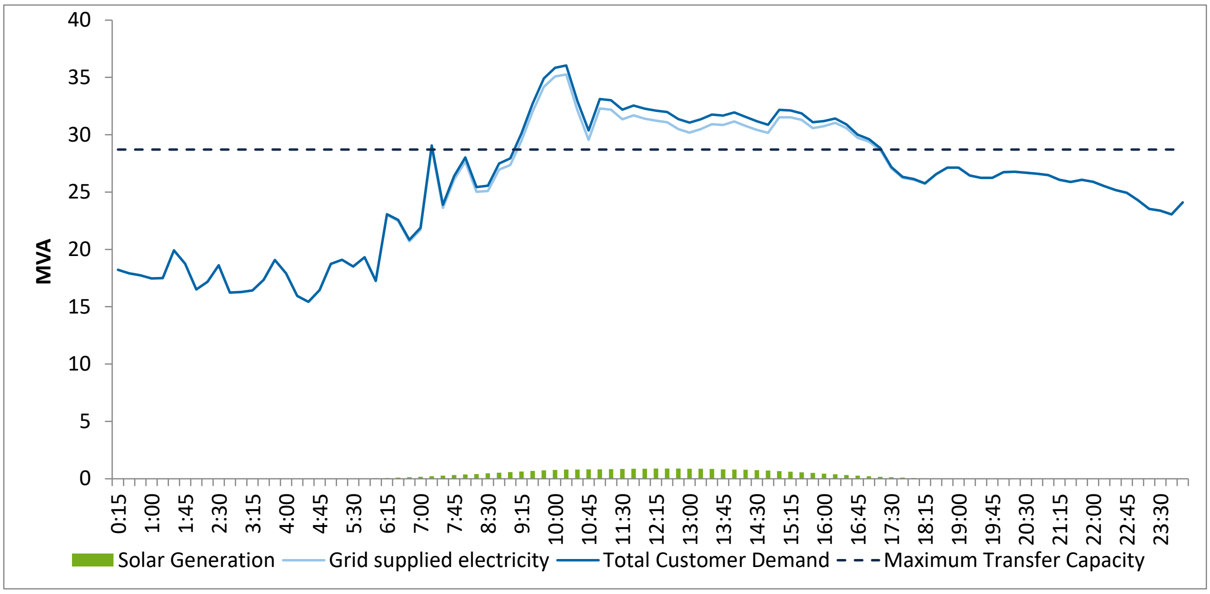
Mascot ZS has a load transfer capacity of 28.7 MVA or about 75% of the weather corrected POE50 peak of 38.3 MVA for summer of 2020/21. The load duration curve including the load transfer capacity is shown in Figure 4.

Figure 4: Mascot load duration curve



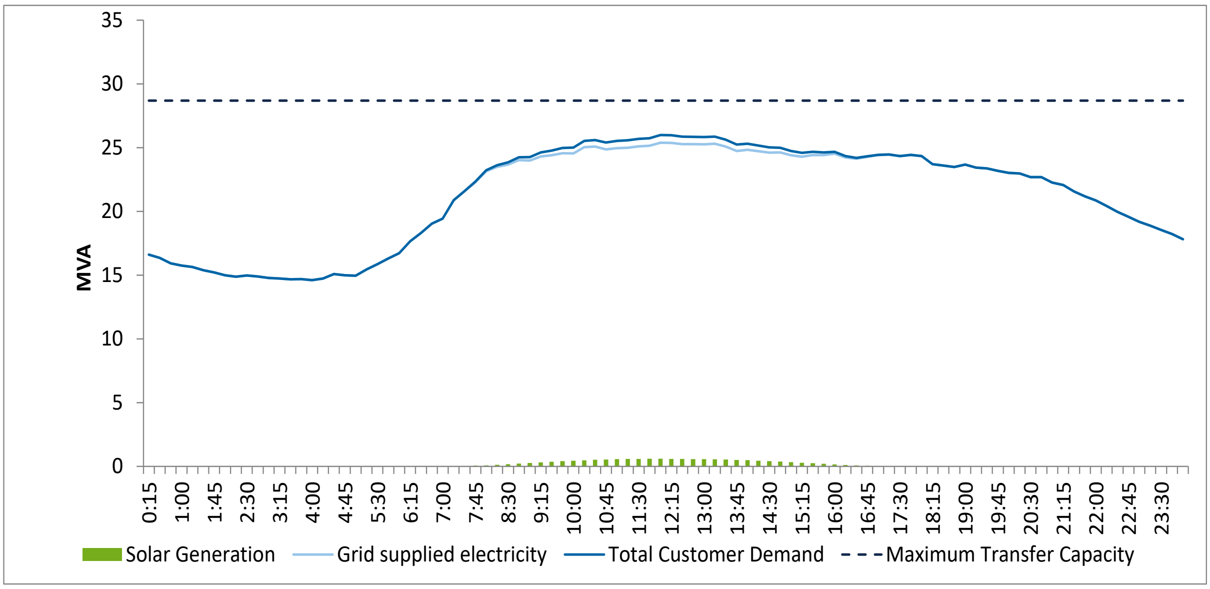
In the event of a network outage on the summer maximum demand day and following realisation of the maximum transfer capacity through network switching, there is a maximum shortfall of around 6.5 MVA when compared to the actual peak (non-weather corrected). The shortfall would occur for most of the day as seen in Figure 5 below.

Figure 5: Summer maximum demand profile at Mascot on 18 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. There is no shortfall when compared to actual peak (non-weather corrected).

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



2.3 Customer characteristics

Mascot ZSs serves a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the Year 2022 period are as follows:

Table 1: Mascot customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	6,103	930	104	7,137
% of Customers	85.5%	13.0%	1.5%	
Annual Consumption (MWh)	23,864	24,053	94,347	142,264
% of Annual Consumption	16.8%	16.9%	66.3%	
Number of Solar Customers	260	29	5	267
% of Customers with Solar	4.3%	3.1%	5.0%	
Average Annual Consumption (MWh)	4	26	907	20

About 26% of residential customers live in detached homes with an average usage of about 5.7 MWh per year. Households living in apartments, villa, townhouses and flats have an average usage of about 3.3 MWh per year.

3 Proposed preferred network option

This section provides details of the credible options that Ausgrid has identified as part of its network planning activities. All costs and benefits presented in this DPAR are in $2023/24, unless otherwise stated.

Table 2: Summary of the credible options considered

Overview	Key components	Estimated capital cost (including decommissioning costs)
Option 1 - Establishing a new Mascot East ZS at an alternative location and decommissioning the current Mascot ZS	• Establishment of a new 132/11kV zone substation to be named Mascot East • Load transfers from Mascot ZS to Mascot East ZS • Decommission Mascot 33/11kV ZS and associated 33kV feeders	$45.3 million
Option 2 – Replacing the compound-insulated switchgear with a modern equivalent technology, utilising an empty area at Mascot ZS for the new switchgear equipment	• Civil works within the existing switchroom building to support switchgear installation • Installation of 11kV switchgear using modern equivalent technology • Load transfers from compound switchgear groups to newly installed 11kV switchgear • Secondary system upgrades • Decommissioning of redundant 11kV compound-insulated switchboards, control panels and transformers	$12.3 million (plus future costs of $20.1 million not assessed in this Screening Notice)
Option 3 – Retiring the three groups of compound-insulated switchgear at Mascot ZS, transferring load to the nearby Green Square ZS, and retaining the air-insulated switchgear in their current configuration (as under Option 2). This option also involves retiring 11kV duct lines and installing 11kV feeders to transfer 11kV loads to Green Square ZS	• Installation of approximately 1,800m of new ductlines, including cable installation and joints • Load transfers from 11kV compound-insulated switchboards to Green Square ZS • Minor works at Mascot ZS to connect the remaining two groups of air-insulated 11kV switchgear, including an additional circuit breaker and bus-tie cable installations • Decommissioning and removal of three groups of redundant 11kV compound-insulated switchboard, control panels and associated transformers from the site	$11.4 million (plus future costs of $19.5 million not assessed in this Screening Notice)

The future costs associated with Options 2 and 3 above relate to the future replacement of the air-insulated switchgear in approximately 20 years' time common under both options. These costs were included for the purposes of NPV assessment to ensure a 'like-for-like' comparison against Option 1 (since condition issues are entirely resolved under Option 1 whereas the initial cost under Options 2 and 3 address only part of the condition issues). The future costs are ignored as part of this Screening Notice assessment as they cannot be assessed for non-network opportunity due to the timeframe involved.

Ausgrid also considered additional options that have 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
Replace all oil circuit breakers (OCBs) with Vacuum Circuit Breakers (VCBs)	Replace OCBs with VCBs to extend the service life of compound insulated switchgear (as has been done elsewhere in the network)	Due to the site configuration at Mascot ZS, this solution requires extensive design work to accommodate VCBs in the existing arrangement. The additional cost of the design work is expected to be substantive and will not remove a significant component of the network risk, as the compound-insulated busbars will remain in service. This option could defer the replacement considered under Option 2 by approximately 5-10 years, but significant costs will be incurred while the EUE risk is not materially removed. Therefore, this option is considered not economically feasible.
Replace the air-insulated switchboard in the scope of Option 2 and Option 3	Replace the air-insulated 11kV switchboard at Mascot ZS at the same time as the upfront compound-insulated switchboard replacement works	The air-insulated switchboard at Mascot ZS is in better condition than the compound-insulated switchboards and is not expected to require replacement for another 20 years. Potential cost savings/efficiencies from doing both works at once cannot be compensated with a corresponding increase in benefits. Therefore, this is considered a suboptimal option.
Retirement of Mascot ZS	Transfer of all 11kV load from Mascot ZS to adjacent zone substations	The existing 11kV loads cannot be fully accommodated in adjacent zone substations such as Green Square, Botany, St Peters and/or Zetland, as there is no adequate spare capacity available. If implemented, the cost would be significant, as it would require network augmentations at some of these adjacent substations. Therefore, this option is considered not economically feasible.
Brownfield replacement of Mascot ZS	Replace all 11kV switchgear equipment on the existing site and replace existing 33kV feeders originated from Bunnerong North STS with new 33kV feeders from nearby Alexandria STS.	This project requires staging to replace sections of the 11kV switchgear, and therefore will take considerably longer than a greenfield replacement (i.e., New Mascot East under Option 1) to be completed. In addition, the brownfield replacement is expected to be more expensive than the greenfield replacement, requiring significant design/development work due to the complexity of working near energised electrical equipment. The combination of greater capital costs requirements and a longer delivery timeframe will provide a suboptimal solution when compared to a greenfield replacement, as the benefits would be the same but likely to take at least two years longer to be realised.

Table 4: Summary of the three scenarios investigated

Variable	Scenario 1 – central scenario	Scenario 2 – low scenario	Scenario 3 – high scenario
Demand	POE50 2022 Step Change	Minimum POE50 demand across AEMO 2022 ISP scenarios	POE10 2022 Step Change
Safety and health risk costs	Central estimate	70 per cent of central estimate	130 per cent of central estimate
Avoided reactive maintenance costs	Central estimate	70 per cent of central estimate	130 per cent of central estimate
VCR	$63.37/kWh across all scenarios		
Discount Rate	3.44% across all scenarios		

Refer to the Draft 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 2 is the preferred option that satisfies the RIT-D. It involves the replacement of the existing 11 kV compound-insulated switchgear at Mascot ZS with modern equivalent switchgear.

The replacement of switchgear under the preferred option will result in substantial market benefits from avoided EUE that would otherwise arise if no action were taken, with secondary benefits including reduced planned and unplanned maintenance costs, and reduced safety risk.

The estimated capital cost of this option is $12.3 million.

Refer to the Draft 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

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 Mascot

Required peak demand reduction	Available demand management funds ($)		
	1 Yr deferral	2 Yr deferral	3 Yr deferral
25MVA*	$104k	$131k	$162k

*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 25MVA of demand reduction is required in 2025/26 with total available demand management funds of $104k, which is equivalent to $4/kVA/year,
- For 2-year deferral, 25MVA of demand reduction in 2025/26 and 2026/27 with total available demand management funds of $131k, which is equivalent to $3/kVA/year, and
- For 3-year deferral, 25MVA of demand reduction is required in 2025/26, 2026/27 and 2027/28 with total available demand management funds of $162k, equivalent to $2/kVA/year

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 Mascot 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.

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

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 less than 3 customers using the entire available funds. 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 (over 4x available funds)
- $900k-1.5m in the 2-year deferral case (over 6x of available funds)
- $1.35m-2.25m in the 3-year deferral case (over 8x available funds)

In all cases the cost of 6MVA of demand response far exceeds the available funds while only addressing a small fraction of the required demand reduction. Consequently, we consider there are 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 214kVA at Mascot 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 1% of the required 25MVA 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 can alleviate the impact of overload conditions. Analysis of interval data for Mascot 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. Incentivising only 1 MW of customer solar power systems exceeds the available funds ($162k for 3 years deferral for example) and only meets a small fraction of the demand

and energy reduction requirements. We therefore consider there are 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 1MVA of reduction at an approximate cost between $200k-$500k, which exceeds the available funds and only meets a small fraction of the demand and energy requirements. Consequently, we consider there are 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 $1 million 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 Mascot 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.