Addressing reliability requirements in Zetland and Waterloo load areas

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

21 October 2022

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Addressing reliability requirements in Zetland and Waterloo load areas

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1 Introduction

The underground electricity subtransmission cables (‘feeders’) supplying the Eastern Suburbs load area include self-contained fluid filled (**SCFF**) feeders, which are now considered an obsolete and outdated technology.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 has made a commitment to the NSW Environment Protection Authority (**EPA**) to a program of replacing or retiring all SCFF cables with known leaks by 2034, due to the environmental risks associated with oil leaking from these cables (as well as the associated decline in network reliability).

Ausgrid has identified the need to mitigate risks associated with 132kV feeders 260 and 261, which run from Beaconsfield Supply Point (**BSP**) to Zetland Zone Substation (**ZS**). If action is not taken, our planning studies indicate that there will be substantial unserved energy to loads in this area of our network if these cables fail, as well as significant reactive maintenance costs associated with having to repair and restore service, and environmental risks from oil leaking from the cables. Without action we expect that our electricity distribution license reliability and performance standards will be breached.

Ausgrid has also identified 132kV feeders 9SA and 92P as a high priority for replacement with modern technology cables, because of the environmental risks associated with potential oil leaks from these cables. Feeders 9SA and 92P run from the Beaconsfield BSP to Campbell St ZS and Belmore Park ZS respectively. They are key feeders that form part of Sydney’s Inner Metropolitan Subtransmission network. Due to their geographic proximity, addressing concerns associated with feeders 9SA and 92P at the same time as replacing feeders 260 and 261 offers cost efficiencies when compared to addressing them in isolation.

Ausgrid has initiated this RIT-D to assess options for addressing the risk that the existing ageing SCFF feeders 260, 261, 9SA and 92P pose 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 Stand Alone Power Systems (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).

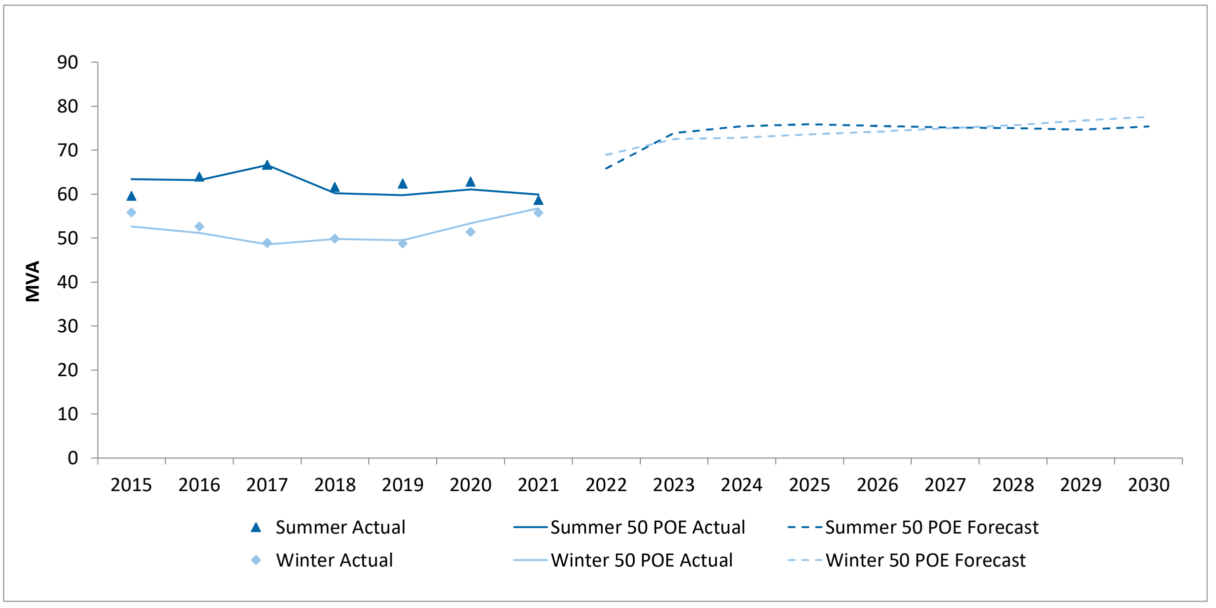
2 Forecast load and capacity

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 Zetland ZS.

Zetland 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 58.7 MVA at 3:15pm AEDT on 29 November 2020. The weather corrected demand at the 50 POE level was 59.9 MVA. The power factor at the time of summer maximum demand was 0.97.

Figure 1: Maximum demand forecast at Zetland ZS

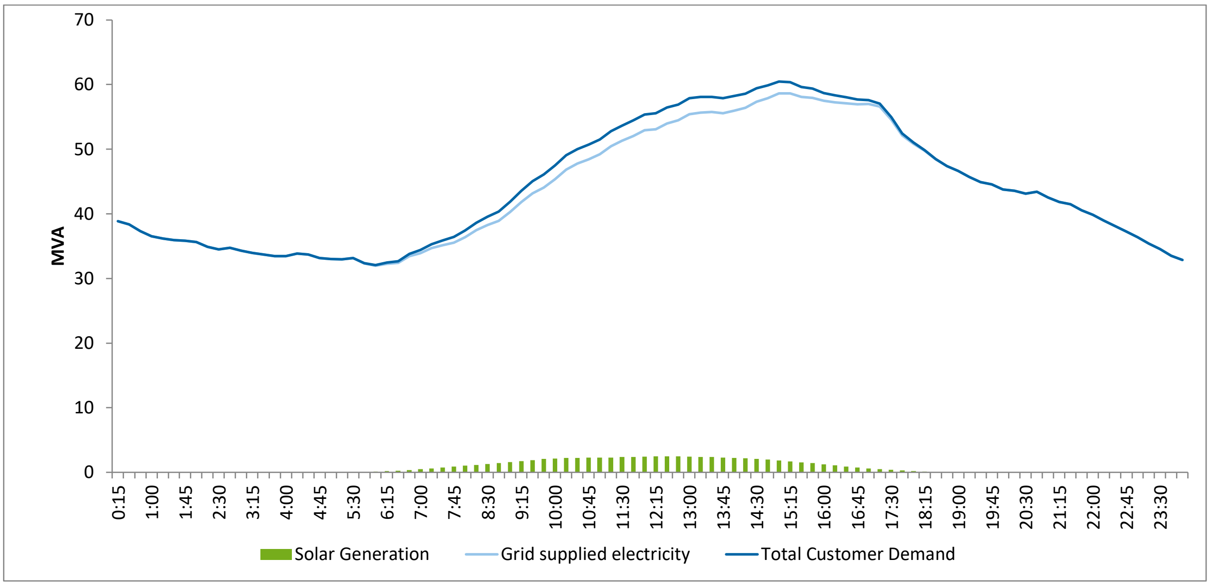


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Zetland ZS has typically occurred in summer between 11:30 and 4:00pm AEDT.

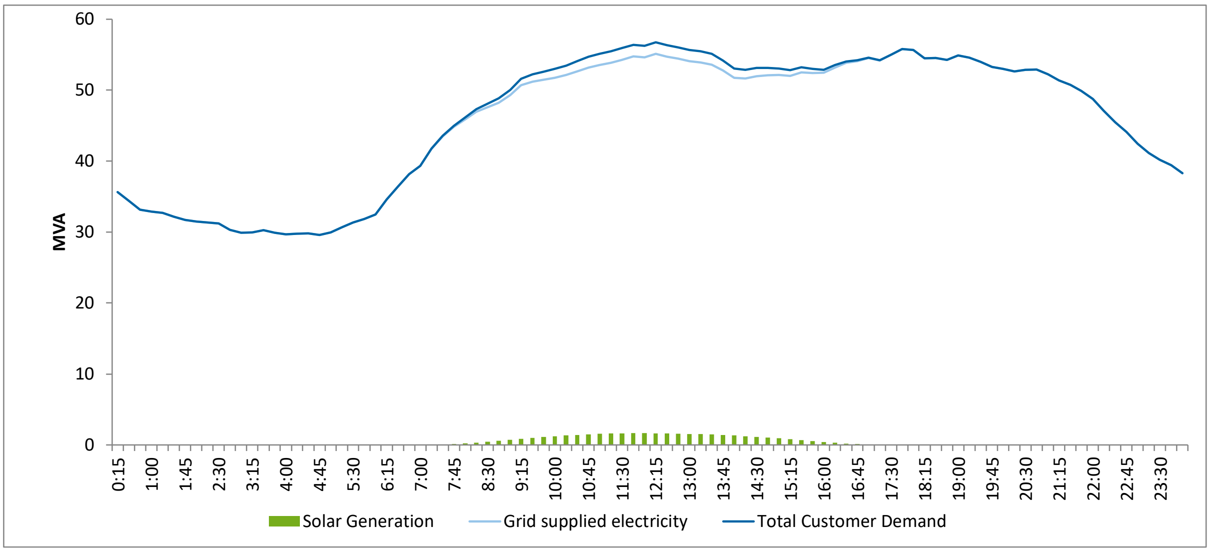
There is a total Solar PV capacity of approximately 3.7 MW connected to Zetland ZS. At the peak time of 3:15pm AEDT on 29 November 2020, these PV systems are estimated to have been generating 1.7 MW. Figure 2 below shows the load trace on this day including the contribution from customer solar power systems.

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



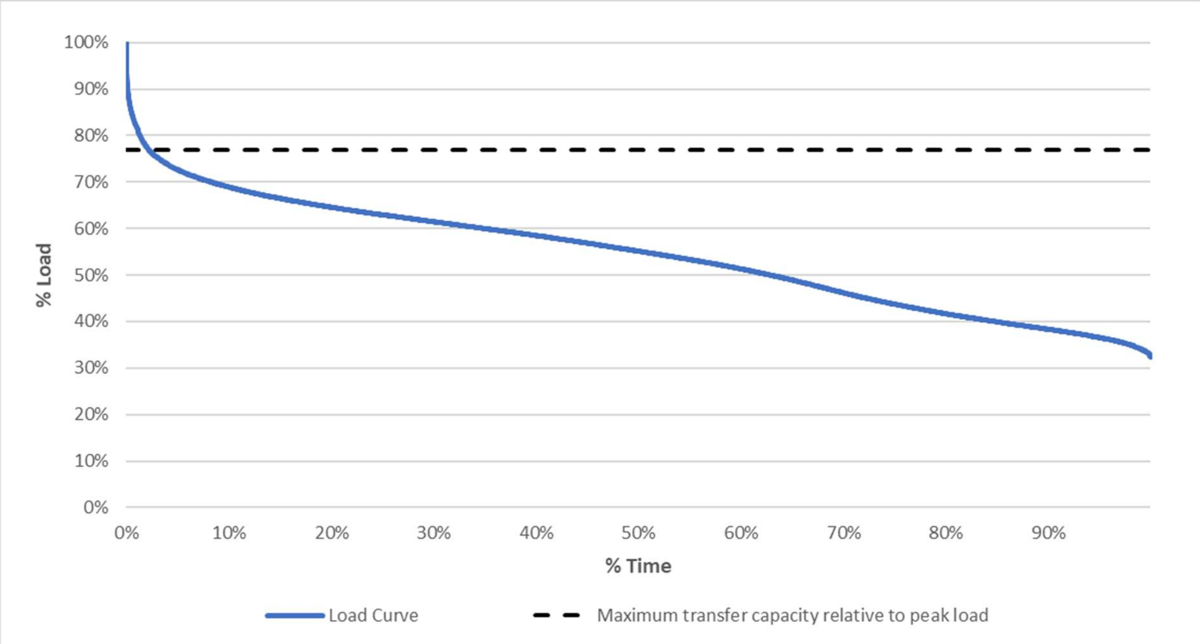
Over the past 7 years, the time of winter peak has typically occurred between 10:45 am and 6:45pm AEST. At the peak time of 5:45pm AEST on 10 June 2021, the estimated generation from PV systems is 1.66 MW. Figure 3 below shows the load profile for the peak demand day 10 June 2021 including the contribution from customer installed solar power systems.

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



Zetland ZS currently has a summer load transfer capacity of 46.1 MVA or about 78.6% of the actual maximum 2020/21 summer demand and a winter load transfer capacity of 45.9 MVA or about 82.3% of the actual maximum for winter 2020. The load duration curve including the load transfer capacity is shown in Figure 4.

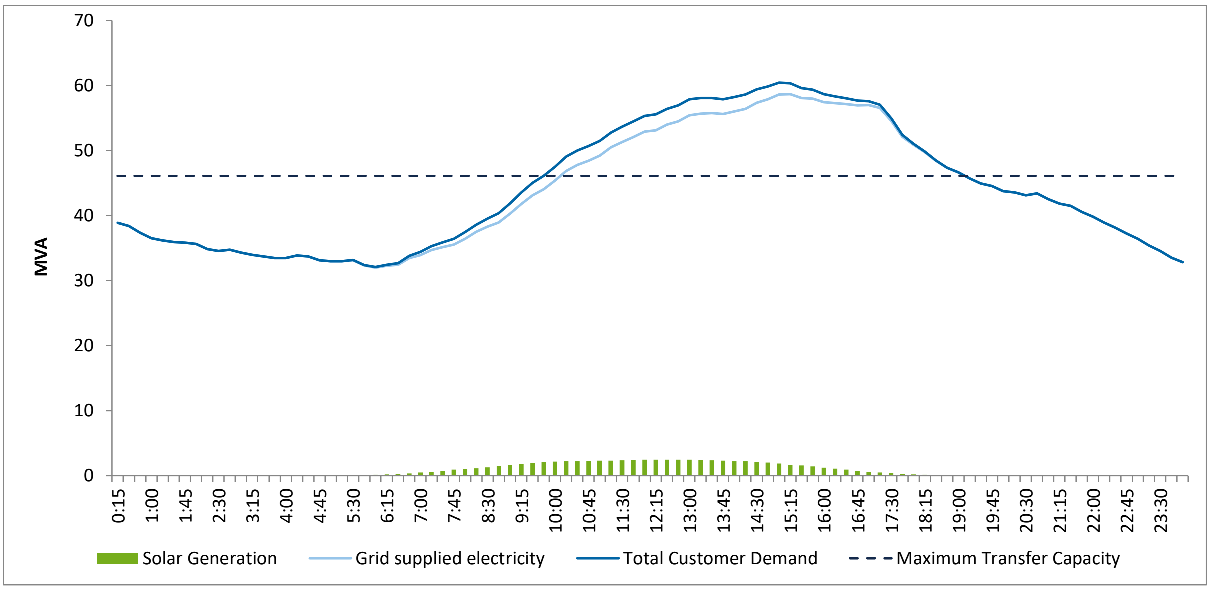
Figure 4: Zetland ZS load duration curve



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 14.4 MVA. The shortfall would occur for a large part of the day as seen in

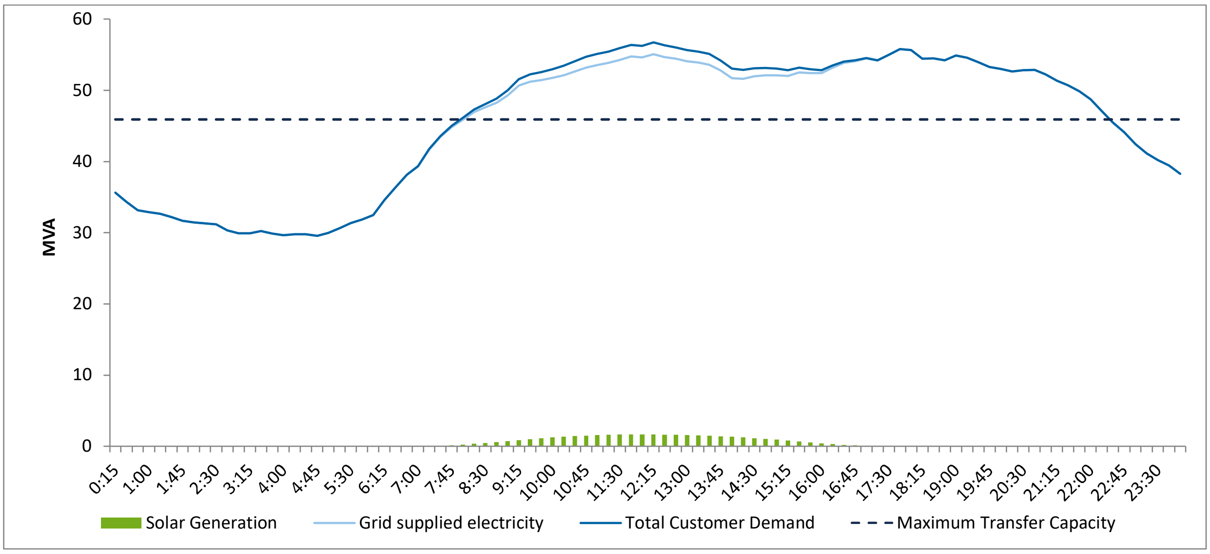
Figure 5 below.

Figure 5: Summer maximum demand profile at Zetland ZS 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 10.8 MVA and there would be a shortfall for most of the day (see Figure 6).

Figure 6: Winter maximum demand profile at Zetland ZS on 10 June 2021



2.3 Customer characteristics

Zetland ZS serves a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2020/21 period is shown below:

Table 1: Zetland customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	20,147	2,210	230	22,587
% of Customers	89%	10%	1%	
Annual Consumption (MWh)	67,293	51,883	146,525	265,702
% of Annual Consumption	25%	20%	55%	
Number of Solar Customers	234	77	19	330
% of Solar Customers	1.2%	3.5%	8.3%	
Average Annual Consumption (MWh	3.3	23	637	12

About 89% of residential customers live in detached homes with an average usage of about 5.3 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.8 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 $2021/22, unless otherwise stated.

Table 2: Summary of the credible options considered

Option	Capital cost	Commissioning
Option 1 – Replace the existing feeders 9SA, 92P, 260 and 261 like-for-like using modern equivalent technology	$52.2 million	2025/26
Option 2 – Replace SCFF sections of feeders 9SA and 9SP, loop Zetland ZS into feeder 92P and close Zetland 132kV busbar	$40.7 million	2029/30
Option 3 – Replace SCFF sections of feeders 9SA and 92P, loop Zetland ZS into feeder 92P and defer works on closing Zetland 132kV busbar	$37.1 million	2025/26

Table 3: Summary of the three scenarios investigated

Variable	Scenario 1 – central scenario	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand*	POE50 Step Change	Minimum POE50 demand across AEMO scenarios	POE10 Step Change
VCR	$61.01/kWh	$45.76/kWh	$76.26/kWh
Unplanned corrective maintenance cost	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Environmental risk costs	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Capital costs[1]	Capital cost central estimates	125 per cent of capital cost estimate	75 per cent of capital cost estimate
Decommissioning costs	Central estimates	125 per cent of capital cost estimate	75 per cent of the central 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.

[1] The variation in capital cost sensitivity also affects planned maintenance since this cost is a proportion of capital expenditure.

3.1 Preferred option at this stage

Ausgrid proposes Option 3 as the preferred option based on the RIT-D. Expected benefits are driven primarily by reduced involuntary load shedding that would otherwise be incurred under the base case, with benefits also arising from avoided planned and reactive maintenance and environmental risk costs.

Option 3 is found to have the highest net market benefits under the central, high and weighed scenarios owing to lower capital costs and an earlier commissioning date, allowing additional years for this option to accumulate benefits (in particular avoided unserved energy) compared to Option 2. Option 2 is the preferred option under the low benefits scenario due to the deferment of costs and reduced unserved energy benefits.

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

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 6 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 Zetland

Deferral year	Required peak demand reduction per year	Available demand management funds	
1 year	11MVA*	$1.6m	$143/kVA/year
2 years	12MVA*	$3.0m	$125/kVA/year
3 years	14MVA*	$4.4m	$104/kVA/year

* 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 11MVA of demand reduction is required in 2024/25 with total available demand management funds of $1.6 million, which is equivalent to $143/kVA/year,
- For 2-year deferral, 12MVA of demand reduction in 2024/25 and 2025/26 with total available demand management funds of $3.0 million, which is equivalent to $125/kVA/year, and
- For 3-year deferral, 14MVA of demand reduction is required in 2024/25, 2025/26 and 2026/27 with total available demand management funds of $4.4 million, equivalent to $104/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. 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[2]. 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 21 to 59 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.

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.

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. Based on the load profile at Zetland zone substation and a forecast peak demand of 75.9 MVA in 2024/25, the top 100 hours of demand corresponds to the top 14MVA of demand. Achieving this magnitude of demand response is likely unachievable, however, assuming that 2MVA 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, the cost of this solution for 2MVA would require:

- $150-250k (9% to 16%) of the available funds in the 1-year deferral case ($1.6m available funds),
- $300-500k (10% to 17%) of the available funds in the 2-year deferral case ($3.0m available funds), and
- $450-750k (10% to 17%) of the available funds in the 3-year deferral case ($4.4m 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 421kVA at Zetland ZS. At a projected demand management cost of about $25-50 per kVA, or a total cost of around $10-21k, the solutions appear cost effective, however, this solution would contribute only 3% of the required 14MVA 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.

[2] 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 Zetland 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 30% 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 14 MW of additional solar could be procured for around $225-275 per kVA, 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 $3.3-4.1m comprising 2MVA of demand response $150-250k for 1 year, 421kVA of power factor correction: $10-21k and 14MW of customer solar systems: $3.2-3.9m which exceeds the available funds under this scenario of $1.6m by between 110-160%. No further funds would be available for other solutions that can reduce demand outside of solar generation hours.

- 2-year deferral: Total cost $3.5-4.4m comprising 2MVA of demand response $300-500k for 2 years, 421kVA of power factor correction: $10-21k and 14MW of customer solar systems: $3.2-3.9m which exceeds the available funds under this scenario of $3.0m be between 20-50%. No further funds would be available for other solutions that can reduce demand outside of solar generation hours.

- 3-year deferral: Total cost $3.6m-4.6m comprising 2MVA of demand response $450-600k for 3 years, 421kVA of power factor correction: $10-21k and 14MW of customer solar systems: $3.2-3.9m which is in line with the available funds under this scenario of $4.4m (81-105% of funds). Funds available for other solutions would be up to $800k.

The 1-year and 2-year deferral scenarios can be eliminated from further analysis due to lack funds for other solutions. Other types of permanent solutions are needed to achieve diversity in demand management solutions and a sufficient quantum of demand and energy reductions to alleviate the level of unserved energy necessary to enable a deferral of the network solution. An energy reduction of around 27GWh per year during times when the substation load exceeds the transfer capacity at Zetland ZS would be required from permanent demand management solutions across the full demand management program to justify a 3-year deferral. The 14MW of solar modelled above would achieve around 6.4GWh or 24% of the requirement.

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 in Section 4.3.4 above, the 1-year and 2-year deferral scenarios are not viable since there are no further funds (already overspent) to achieve a viable demand management program. Under the 3-year deferral scenario, there remains up to $800k following procurement of demand response, power factor correction and customer solar power systems.

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 a typical commercial premises that operates around 2000hrs per year (8am-5pm Mon-Fri and closed over Christmas holidays) and 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 might achieve up to 4MVA, or 2.5 GWh in annual energy efficiency savings, using up all of the remaining funds ($800k) under the 3-year deferral case.

As mentioned in Section 4.3.4 above, an energy reduction of around 27GWh would be required from permanent demand management solutions across the full demand management program to justify a 3-year deferral. Adding on the 4MVA energy efficiency, the total estimated unserved energy reduction of the modelled demand management program using all the funds equates to around 9.0GWh or 33% of the target 27GWh, which is insufficient to address the energy shortfall to justify deferral of the network solution by 3 years. 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

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 Zetland 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, $1.6-4.3m for 1 to 3 years deferral respectively, 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.