Addressing increased customer demand requirements in the Macquarie Park area

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS REPORT

AUGUST 2018

Ausgrid

Addressing increased customer demand requirements in the Macquarie Park area

Notice on screening for non-network options – 31 August 2018

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1 Introduction

The future combined load increases from several major customers in the Macquarie Park supply area is anticipated to cause significant constraints on the existing Ausgrid 11kV network and a long term 33kV supply strategy presents an opportunity to support all customers efficiently.

A number of major customers[1] approached Ausgrid to initiate the connection applications process in 2017. Section 5.2.3 of the National Electricity Rules (NER) obliges Ausgrid to enable connection of these customers to the distribution network[2].

Two of these customers have progressed with formal connection applications and confirmed their load requirements and expected connection dates. In particular, these two customers are requesting approximately 91MVA by 2021/22. In addition, there is a prospective third customer with a load requirement ramping steadily from 2021 with an ultimate load of 46MVA.

The scale of expected load required by these customers is such that the existing network cannot accommodate these loads without augmentation. Ausgrid has therefore identified the need to augment the subtransmission network supplying the Macquarie Park area and is commencing this RIT-D.

The expected capital cost of the proposed investment to facilitate these loads is greater than $5 million (i.e. the threshold for having to apply a RIT-D). Ausgrid notes that this substation will be a shared network asset which will become part of Ausgrid's Regulatory Asset Base. As these prospective customers are expected to utilise over 95% of the asset – if the three customers are committed, specific tariff arrangements will be established to recover the majority of the cost of the augmentation from the beneficiaries (i.e. the new customers), taking into account their share in the capacity added to the network. It is noted that these customers will directly fund the dedicated assets associated with their connections.

These customers will be charged a cost reflective network price, determined specifically from this network augmentation investment, plus allocated costs from the use of the upstream system - i.e. through 'Distribution Use of System (DUOS) tariffs.

Whilst Ausgrid has an obligation to enable the connection of these customers, in accordance with section 5.3 of the NER, construction works will only commence on this augmentation once the corresponding connection agreement contracts have been signed.

A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR) for addressing increased customer demand in the Macquarie Park zone substation.

This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ausgrid's determination that no non-network option is, or forms a significant part of, any potential credible option for this RIT-D. In particular, it sets out the reasons for Ausgrid's determination, including the methodologies and assumptions used.

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[1] At this stage, it would be inappropriate to name these customers due to commercial sensitivities. As discussed in this DPAR, once these customers have signed connection agreements with Ausgrid, their details will be able to be released.

[2] Specifically, clause 5.2.3(d) items 1 and 6, as well as 5.2.3(e1) outlines the connection and network management obligations for Ausgrid as a network service provider.

2 Forecast load and capacity

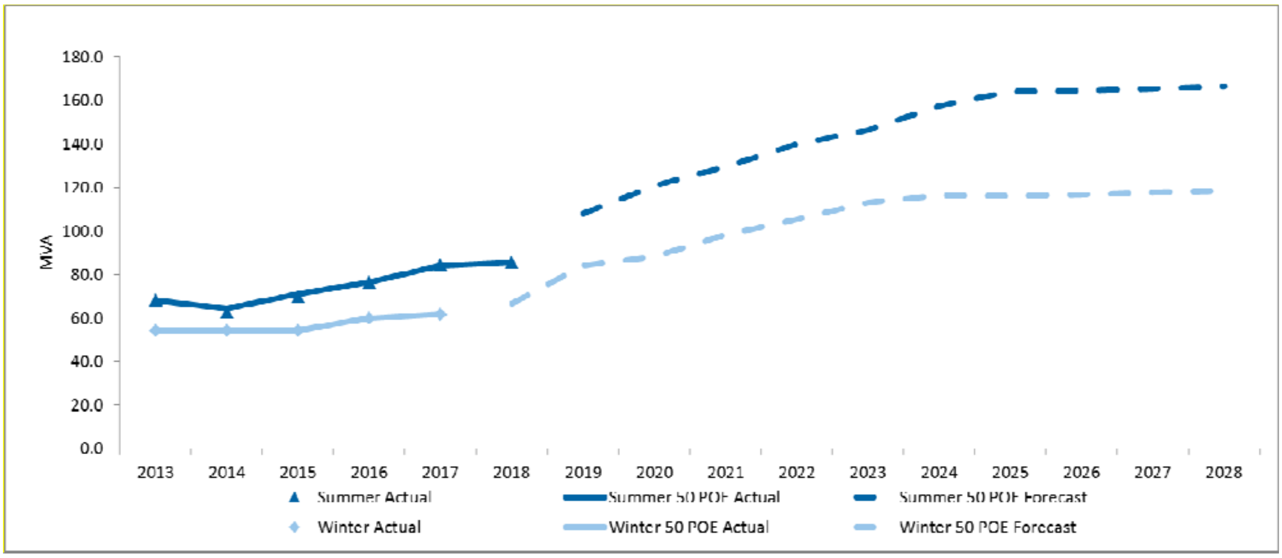
2.1 Load forecast

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 for both winter and summer for Macquarie Park zone substation.

The Macquarie Park zone substation has a total capacity of 171.5 MVA and a firm capacity of 114.3 MVA. In 2017/18, the maximum demand on zone substation was 85.5 MVA at 2:00pm AEDT on 22 January 2018. The weather corrected demand at the 50 POE level was 85.5 MVA. The power factor at the time of winter maximum demand was 0.97.

Maximum demand has typically occurred in summer in past years. In the summer season, the maximum demand typically occurs between 1:15pm and 4:15pm AEDT. The 50 POE forecast 7 year compound annual growth rate (CAGR) to 2024/25 for maximum demand is 9.8% for summer and 9.5% for winter. As shown in Figure 1 below, maximum demand is forecast to reach 140 MVA by 2022 and 165 MVA by 2026; driven substantially by load to supply new large scale customer load.

Figure 1 – Demand forecast at Macquarie Park zone substation



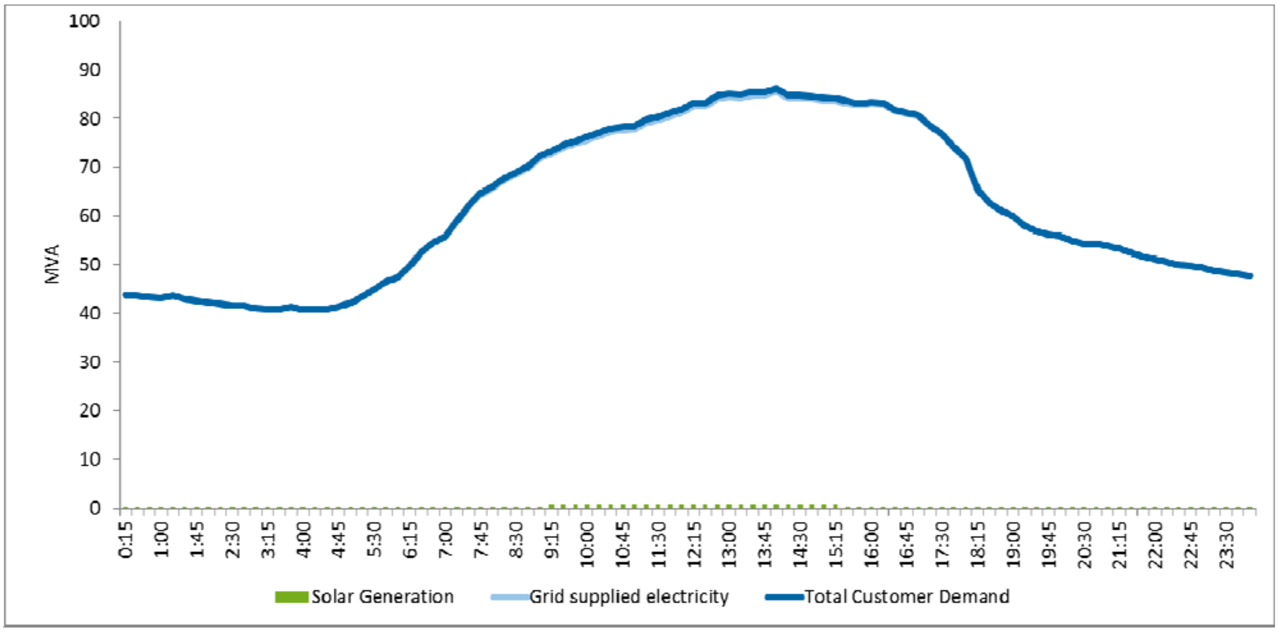
2.2 Current pattern of use

Summer peak electricity demand at Macquarie Park zone substation occurs on hotter days driven predominantly by commercial loads.

Over the past 7 years, and where peak annual demand occurs in summer, the time of peak has typically occurred between 1:15pm and 4:15pm AEDT. As noted above, the most recent summer maximum demand occurred at 2:00pm AEDT on 22 January 2018.

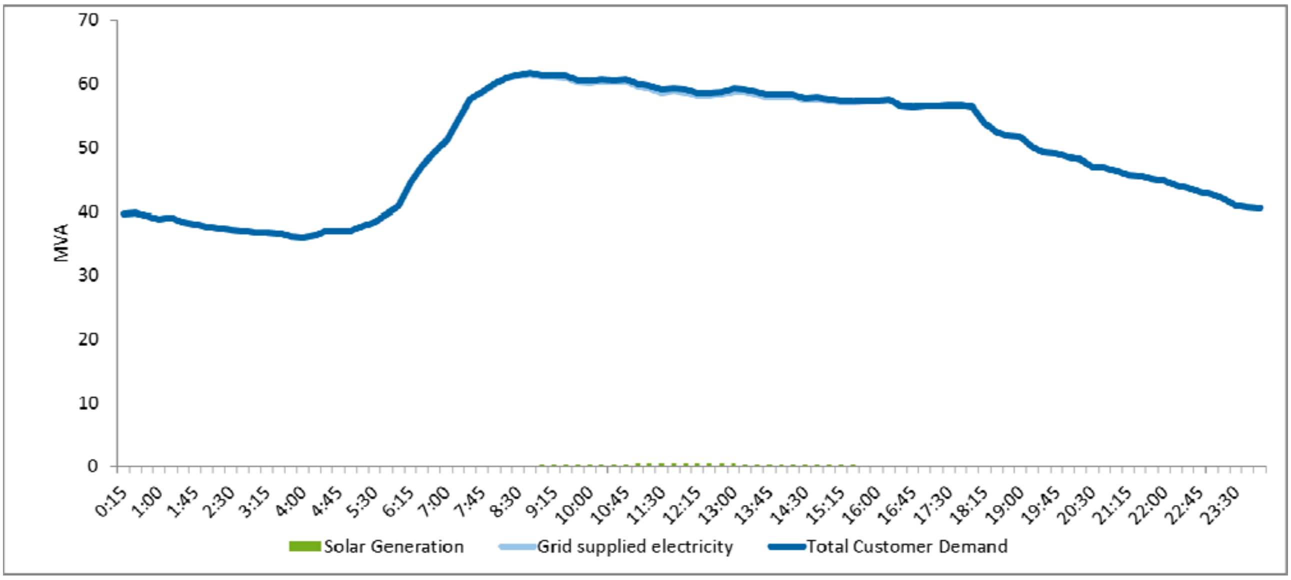
There is currently a total capacity of about 1.1 MW of solar PV connected to the zone substation. At the peak time on 22 January 2018, these PV systems supplied about 0.7 MW of the customer load. Figure 2 below shows the load profile for the 22 January 2018 maximum demand day including the contribution from customer installed solar power systems.

Figure 2 – Summer maximum demand profile at Macquarie Park zone substation (22 January 2018)



Over the past 7 years, the time of winter peak has occurred between 8:45am and 1:45pm AEST. The most recent winter maximum demand occurred at 8:45am AEST on 3 July 2017. Figure 3 below shows the load profile for the 3 July 2017 winter peak demand day including the contribution from customer installed solar power systems.

Figure 3 – Winter maximum demand profile at Macquarie Park zone substation (3 July 2017)



2.3 Forecast pattern of use (2021/22)

The recent customer connection requests have resulted in a significant increase in the forecast load in the Macquarie Park area. Two of these customers have progressed with formal connection applications and confirmed their load requirements and expected connection dates. After adjustments and coincidence factors have been applied, customer demand in the Macquarie Park area is forecast to grow by 54 MVA to 140 MVA by 2022 with about 80% of the growth attributed to the recent customer connection requests. This is well in excess of the firm capacity of Macquarie Park ZS of 114.3 MVA. Under a 'do nothing' scenario, there will be a forecast overload of 25.6 MVA in 2021/22, or about 22% over firm capacity.

To quantify the scale of the overload, a forecast annual load profile for Macquarie Park ZS was prepared. Representative historical meter data for the new customer connection requests served as a proxy for the new customer load and the existing Macquarie Park load profile was assumed to remain unchanged. Based upon the forecast 2021/22 load profile, the shortfall in supply to customers is displayed for summer and winter peak days in Figure 4 and 5 below.

Figure 4 – Forecast 2021/22 Summer maximum demand profile at Macquarie Park zone substation

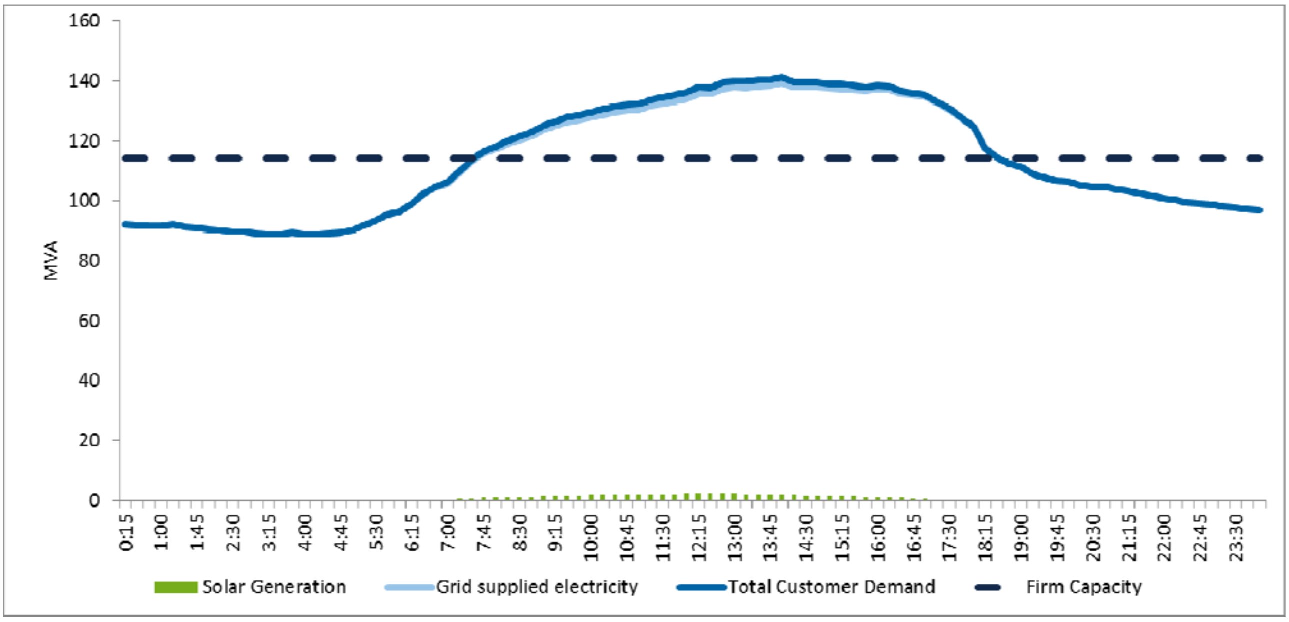
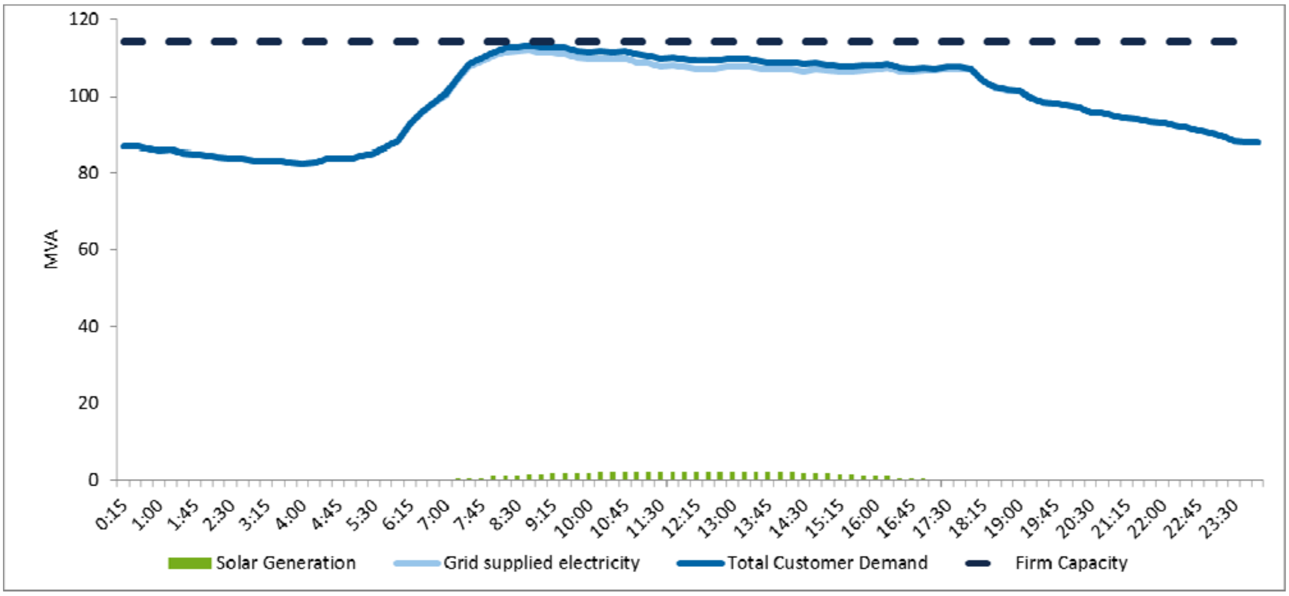
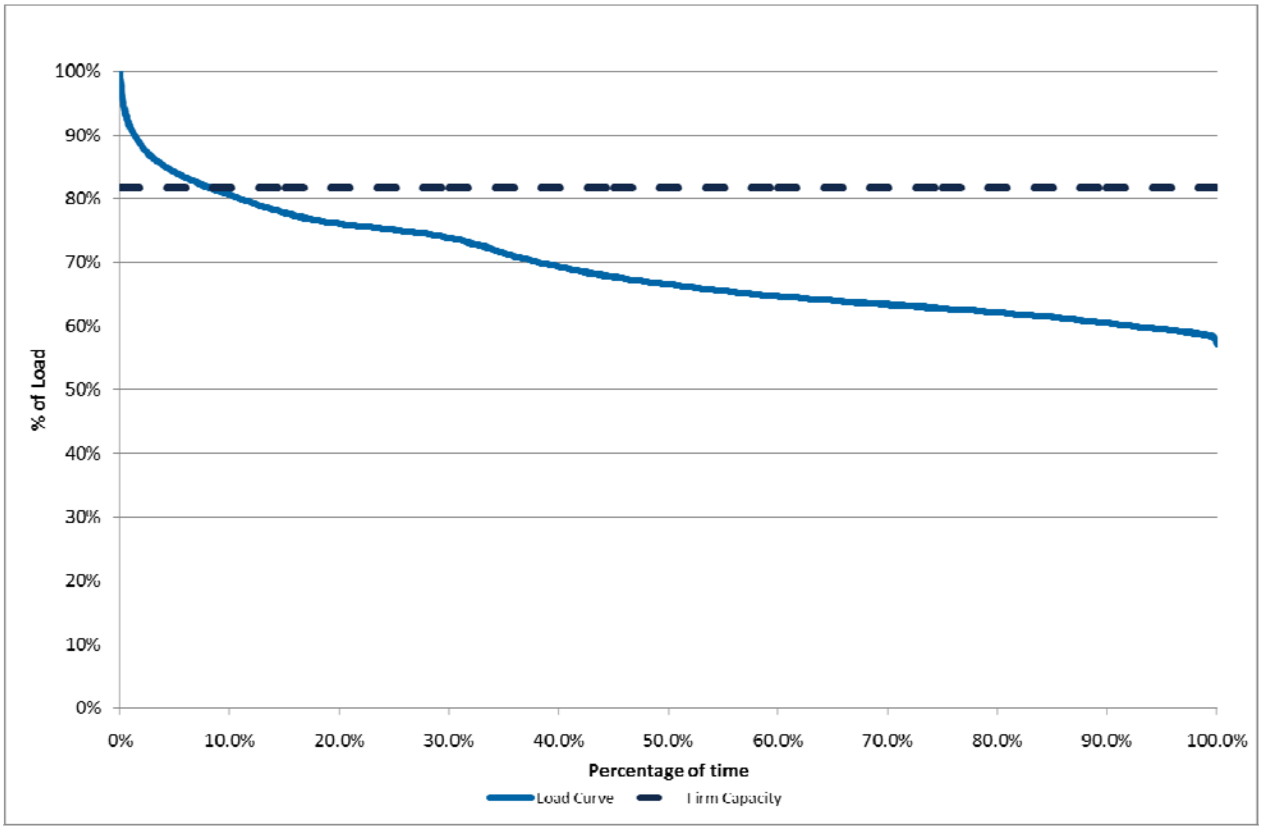


Figure 5 – Forecast 2021 Winter maximum demand profile at Macquarie Park zone substation



For the 2021/22 year, electricity demand for Macquarie Park zone substation is forecast to exceed the firm capacity of 114.3 MVA for about 116 days and 830 hours per year (9.5% of total hours).Over this period there is a total of about 5,350 MWh of energy above the current firm capacity of Macquarie zone substation. The load duration curve for the forecast 2021/22 year, noting the firm capacity, is shown below in Figure 6.

Figure 6 – Forecast 2021/22 Load Duration Curve at Macquarie Park zone substation



2.4 Customer characteristics

Macquarie Park zone substation currently serves a mixture of residential and non-residential customers with over 93.2% of annual electricity consumption from non-residential customers. A breakdown of the customer characteristics for the 2016/17 period is as follows:

Table 1 – Customer characteristics – Macquarie Park zone

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	3,823	730	240	4,793
% of Customers	79.8%	15.2%	5.0%	
Annual Consumption (MWh)	24,909	27,738	315,569	368,216
% of Annual Consumption	6.8%	7.5%	85.7%	
Number of Solar Customers	716	25	5	746
% of Solar Customers	96%	3%	1%	
Average Annual Consumption (MWh per customer)	5.9	19	456	

About 50% of residential customers live in detached homes with an average usage of about 8.6 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 4.4 MWh per year.

3 Proposed preferred network option

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

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

A summary of the key variables in each scenario is provided in the Table 2 below.

Table 2 – Summary of the three scenarios investigated

Variable	Scenario 1 – baseline	Scenario 2 – low benefits	Scenario 3 – high benefits
Load Growth	Expected load growth	Lower than expected load growth	Higher than expected load growth
VCR	\$41/kWh (Derived from AEMO VCR estimate of \$38.35/KWh at state level, CPI indexed)	\$29/kWh (30 per cent lower than AEMO VCR estimate)	\$53/kWh (30 per cent higher than AEMO VCR estimate)
Commercial discount rate	6.13 per cent	8.07 per cent	4.19 per cent

Ausgrid has identified only one credible network option to address the immediate capacity constraint resulting from the growing customer demand in the Macquarie Park area. Other options could technically address the identified need, but are unable to meet the customer required connection date or cost significantly more without providing corresponding increases in benefits. The other options considered include establishing a new STS on a greenfield site and initial 11kV supply to these customers from Top Ryde ZS with a future STS after two years. However, these options are unlikely to be technically feasible, significantly more expensive comparatively or unable to meet the customer requested connection date. In particular, the initial 11kV supply would involve the installation of a significant number of 11kV feeders that may not be accommodated in the area due to the existing congestion of cables as well as from other nonelectrical assets, and would result in significant rating and construction issues.

Preferred option at this draft stage

The identified credible option involves constructing a new 132/33kV STS at the existing Macquarie Park ZS site and associated feeder work. This option is the most cost effective and time efficient option that can meet the customer's required load and time. The option involves the construction of a new STS equipped with two 120MVA 132/33kV transformers utilising the vacant land on the existing Macquarie Park ZS site. A new 132kV feeder will be installed and the 132kV feeders supplying Macquarie Park ZS will be rearranged to facilitate supply to the new STS. 33kV ductlines will also be installed to facilitate customer connections.

The estimated capital cost of this option is approximately \$35.5 million and its commissioning date is expected to be in 2021/22. Once the new STS is completed, it is assumed that operating costs are expected to average 0.5% of the capital expenditure per annum (i.e. \$177,000/year).

Considering this project is triggered by the major customers requesting network connection, specific tariff arrangements will be established to recover the cost of the upstream network augmentation from beneficiaries, taking into account their share in the capacity added to the network. The cost recovery mechanism will be part of the customer connection agreements and acts as a means of mitigating against the risk of having stranded network assets. It is noted that customers will directly fund the dedicated assets associated with their connections.

4 Assessment of non-network solutions

4.1 Required demand management characteristics

A viable demand management solution must be capable of reducing the overload on Macquarie Park zone substation sufficiently to retain supply to all customers. By 2021/22, a capacity shortfall would exist for 116 days in the year and is at a maximum of about 200 MWh per day in the summer period. By 2024/25, a capacity shortfall would exist for 364 days in the year and is at a maximum of about 615 MWh per day in the summer period. A summary of the forecast shortfall in 2021/22, 2022/23, 2023/24 and 2024/25 is detailed in Table 3 below.

Table 3 – Network support required at Macquarie Park zone substation

Year	Maximum demand (MW)	Daily supply shortfall (MWh/day)		
		Minimum	Maximum	Average (non-zero)
2021/22	25.6	0	200	46
2022/23	32.1	0	284	118
2023/24	43.2	0	471	160
2024/25	49.7	0	615	283

Due to the scale of the overload and the load profile at the zone substation, we consider that a combination of permanent and temporary demand reductions might offer the most plausible scenario for a possible cost effective non-network alternative. Refer to Section 2 for details on the load profiles, demand forecasts and customer 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 to satisfy the requested customer connection date in 2021/22 for deferral of the network investment.

4.2 Demand management assessment

Ausgrid has assessed potential demand management options to achieve the required demand reduction to make the project deferral technically and economically viable. As a plausible solution is likely to be a mix of permanent and temporary grid demand reductions, we have assessed permanent and temporary options separately to determine the likely funds available for each element of the proposed solution mix.

Total available funds for a blended solution comprising temporary and permanent demand reductions sufficient to address the forecast overload condition are $2.05m for a one year deferral of the network investment, $4.1m for a two year deferral and $6.1m for a three year deferral.

4.2.1 Demand management element 1: Demand Response (temporary, dispatchable)

Demand response is the most common demand management option and offers a relatively mature solution for standard network overload needs. Demand response can involve either or both a temporary reduction in customer load and the use of embedded generation to either replace grid supplied electricity to the customer or export to the local grid. For the purposes of this option, we have assumed that this solution would address the overload condition for about 10 days and 40-60 hours per year. Past practice shows that costs for traditional demand response are in the range of $75-150 per kW for 30-50 hours of dispatch and 3-4 months availability. These unit rates are used to derive the budget costs for delivery of the required demand response element of the overall demand management solution.

Note that the figures in Table 4 represent only a portion of the required demand reduction. Refer to Section 4.2.2 for details on the remaining demand reductions required to address the total forecast overload condition.

Table 4 – Dispatchable network support required at Macquarie Park zone substation

Deferral period	Deferral Year	Peak Load Reduction required (MW)	Days required	Hours required	Total MWh required	Budget cost
1 year	2021/22	9	11	55	219	$0.7-1.4m
2 year	2021/22	9	11	55	219	$0.7-1.4m
	2022/23	9	12	58	241	$0.7-1.4m
	Total	18	22	113	460	$1.4-$2.7m
3 year	2021/22	9	11	55	219	$0.7-1.4m
	2022/23	9	12	58	241	$0.7-1.4m
	2023/24	9	13	64	276	$0.7-1.4m
	Total	27	35	177	736	$2.1-$4.2m

Note that at this stage, the availability, customer willingness to contract and actual cost for the demand response capability noted in Table 4 is an estimate for the purposes of the screening test only.

If viable, this element of a possible solution would address 4% of the energy shortfall in 2021/22, 2% of the energy shortfall in 2022/23 and 0.6% of the energy shortfall in 2023/24.

Based upon these cost estimates; to address the remaining risk, the available funds to fund the permanent solutions would be $0.65-1.35m for a one year deferral, $1.4-2.7m for a two year deferral and $1.9-4.0m for a three year deferral.

4.2.2 Demand management element 2: Energy Efficiency & Solar (permanent, non-dispatchable)

While still rare for use in demand management in Australia, accelerating the take-up of energy efficiency and solar investments by customers to reduce customer grid supplied electricity can reduce large scale overload conditions and defer network investments. The table below shows the required reductions and available funds for a permanent reduction in the customer load for deferral of one, two and three years. Available funds for this option were derived as per Section 4.2 above.

The total MWh required represents the total remaining annual energy overload after demand response.

Table 5 – Permanent network support required at Macquarie Park zone substation

Deferral period	Deferral Year	Peak Load Reduction required (MW)	Days Required	Hours Required	Total MWh required	Total available funds
1 year	2021/22	16.6	116	831	5,127	$0.65-1.35m
2 year	2021/22	16.6	116	831	5,127	
	2022/23	23.1	229	1,754	13,434	
	Total	23.1	229	1,754	13,434	$1.4-$2.7m
3 year	2021/22	16.6	116	831	5,127	
	2022/23	23.1	229	1,754	13,434	
	2023/24	34.2	301	3,908	47,734	
	Total	34.2	301	3,908	47,734	$1.9-$4.0m

This indicates that there is about $40-80 per kW for permanent reductions for a one year deferral, $60-120 per kW for permanent reductions for a two year deferral and $55-115 per kW for a three year deferral. Note that the reductions comprise 20%, 27% and 40% of the current maximum demand for the Macquarie Park area. A permanent solution would need to address the remaining 96% of the energy shortfall in 2021/22, 98% of the energy shortfall in 2022/23 and 99.4% of the energy shortfall in 2023/24.

An assessment of selected permanent demand reduction solutions is detailed in Section 4.3.

4.3 Demand management options considered

Ausgrid has considered a number of demand management solutions to determine their commercial and technical feasibility to assist with the identified need at the Macquarie Park zone substation. Each of the demand management solutions considered is summarised below.

4.3.1 Customer power factor correction

As a mature and proven demand management solution, customer power factor correction is both technically feasible and offers reliable permanent reductions sufficient at a low cost. Of the 970 non-residential customers connected to Macquarie Park zone substation, about 240 are on a kVA demand tariff. Analysis of customer interval data indicates a technical potential of about 1275kVA. Commercial potential is likely to range from 800 to 1080 kVA. At a projected cost of about $25-50 per kVA, this solution is likely to be cost effective, but contribute to only about 6% of the permanent demand reduction requirement in 2021/22, 4% in 2022/23 and 3% in 2023/24.

4.3.2 Customer solar power systems

The proposed approach would be to provide a financial incentivise to customers to invest in new solar power systems such that an accelerated take-up of solar reduces the forecast demand and energy overload conditions. Analysis of interval data for Macquarie Park zone substation show that solar generation is largely coincident with the energy shortfall such that solar generation is greater than about 30% of maximum panel capacity for about 90% of overload hours. This indicates that this solution might be viable. To assess the viability of this solution, the expected incentive costs and the demand and energy reductions from a 250% increase in the installation rate of solar power systems above the forecast trend (70% additional) were determined. Note that no assessment of available roof space or customer load has been made to assess whether a 250% increase is possible; rather the estimate has been selected to screen the option for scale and cost measures.

At present there is 1.1 MW of solar connected to Macquarie Park zone substation; projected to be 3.3 MW in 2021/22, 4.1 MW in 2022/23 and 4.5 MW in 2023/24. A 250% increase in the installation rate of solar power systems above the forecast trend is estimated to contribute about 1.5-3.5 MW in peak reductions by 2021/22 or about 10-20% of the permanent peak reduction requirement in that year. Assuming a similar higher level of solar installations, the peak reduction impact is estimated to be 2.2-4.8 MW by 2022/23 or again about 10-20% of the permanent peak reduction requirement in that year. For 2023/24, these assumptions imply that the peak reduction impact is estimated to be 2.5-5.5 MW by 2023/24 or about 7-16% of the permanent peak reduction requirement in that year.

For the energy shortfall, the assumed increase in solar installations would address about 30% of the energy overload requirement in 2021/22, 30% of the energy overload requirement in 2022/23 and 25% in 2023/24.

As this approach has not been used widely at a local level, the incentive costs to encourage such an accelerated take-up rate are not known. But assuming that an incentive of about 15% of install cost could encourage such a customer response implies a total cost of over $1.9m by 2021/22 or about 140-270% of the available funds for a one year deferral. For a two year deferral, these costs would imply a demand management cost of $2.6m by 2022/23 or about 95-190% of the available funds. For a three year deferral, costs are estimated to be about $3.0m by 2023/24 or about 75-150% of the available funds.

While this option is likely to be technically feasible and offers permanent reductions that are coincident with the overload condition, incentivising an accelerated take-up of new solar power systems by customers does not appear to offer a cost competitive price or the scale required.

4.3.3 Customer energy efficiency

The proposed approach would be to provide a financial incentivise to customers to invest in improvements to customer energy efficiency such that an accelerated take-up of the energy efficiency improvements reduces the forecast demand and energy overload conditions. Analysis of interval data for Macquarie Park zone substation shows that commercial energy efficiency improvements are likely to be largely coincident with the energy shortfall. This indicates that this solution might be viable. To assess the viability of this solution, the expected incentive costs and the demand and energy reductions from a 100% increase in the installation rate of energy efficiency improvements above the forecast trend (50% additional) were determined. No assessment of existing customer load or potential energy efficiency opportunities has been made to assess whether a 100% increase is possible; rather the estimate has been selected to screen the option for scale and cost measures.

Note that discussion with the new customers requesting connection has shown that the scale of the new energy use is such that energy efficiency is a key focus and that new facilities will largely have adopted the latest energy efficiency equipment. Consequently, it is assumed that energy efficiency opportunities in the timeframe will largely be restricted to existing customer load.

But while there are likely to be opportunities for energy efficiency improvements from existing customer load in the Macquarie Park area, this is likely to be tempered by the fact that the building stock is recent and consequently may offer fewer opportunities to leverage renewal investments by customers. Notwithstanding this, to estimate the likely cost effectiveness of this solution, we have estimated the impacts and costs for a 100% increase in the rate of energy efficiency improvements above that assumed in the demand forecast.

Assuming this higher rate of uptake by customers indicates an impact of about 2.2 MW at peak by 2021/22 or about 13% of the permanent peak reduction requirement in that year. Assuming a similar higher level of customer investment in following years, the peak reduction impact is estimated to be 3.3 MW by 2022/23 (15% of the permanent peak reduction requirement in that year) and 4.5 MW by 2023/24 (13% of the permanent peak reduction requirement in that year).

Coincidence of the available energy efficiency solutions with the overload condition is unknown, but assuming that 60-80% of energy reductions are coincident, it is estimated that the projected increase in energy efficiency improvements would address about 15-20% of the energy overload requirement in 2021/22, 20-25% in 2022/23 and 20-25% in 2023/24.

Assuming that incentives of about 25% of customer investment could encourage customers to install a greater scale of energy efficiency improvements than would otherwise occur, we estimate an average cost of about $900 per kW incentive, adjusting for the additionality effects assumed (50%). For the estimated reductions, this implies a total cost of about $2m by 2021/22 or about 140-280% of the available funds for a one year deferral. For a two year deferral, costs are estimated to be about $3m by 2022/23 or about 110-210% of the available funds. For a three year deferral, costs are estimated to be about $4m by 2023/24 or about 95-190% of the available funds.

While this option is technically feasible and offers permanent reductions that are coincident with the overload condition, incentivising an accelerated take-up of energy efficiency improvements by customers does not appear to offer a cost competitive price or the scale required.

4.3.4 Demand response (curtailment of load)

Customer curtailment of load is a common and effective technique for deferring network investment for standard network overload needs. As noted in Section 4.2.1 above, large customer demand response has historically been priced at $75-150 per kVA for 30-50 hours of dispatch per season while residential air conditioner demand response has been shown to be acceptable to small customers at incentive payment levels of about $150 to $250 per kVA for 20-30 hours of dispatch per season (excluding acquisition costs).

Also as noted in Section 4.2.1 above, this element of a possible solution would address only 4% of the energy shortfall in 2021/22, 2% of the energy shortfall in 2022/23 and 0.6% of the energy shortfall in 2023/24.

4.3.5 Dispatchable generation

Dispatchable generation is another common and effective technique for deferring network investment for standard network overload needs. As noted in Section 4.2.1 above, large customer demand response has historically been priced at $75-150 per kVA for 30-50 hours of dispatch per season and might address up to 4% of the energy shortfall in 2021/22, 2% of the energy shortfall in 2022/23 and 0.6% of the energy shortfall in 2023/24.

Note that as this option commonly sources existing standby diesel generators; environmental compliance and Council DA issues may constrain availability of this solution.

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 of commercial scale battery storage solutions are unlikely to result in a material take-up of these systems by large customers. Recent surveys by Ausgrid of medium and large customers on issues related to investments in solar power, battery storage and energy efficiency has shown that these customers expect a return on investment which is not projected to be available for some time.

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, a Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.