Addressing reliability requirements in the Concord load area

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

22 OCTOBER 2020

Ausgrid

Addressing reliability requirements in the Concord load area

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1 Introduction

The suburb of Concord is located at the northern part of the Inner West area of Sydney. The suburb and surrounding area are served by the Concord 33/11kV zone substation, which was first commissioned in 1955. A critical component in the substation is the 11kV double bus switchboard, which is compound insulated, with 11kV bulk oil circuit breakers (OCBs). The compound insulated switchgear installed across Ausgrid network exhibit failures that have led to consequences ranging from simple equipment failures to fire events and structural damage. Although a range of measures have been implemented to mitigate these consequences, the 11kV switchgear is beyond its design life with continued service resulting in continuing condition deterioration, which increases the risk of supply outage and safety incidents. Consequently, Ausgrid has prioritised the retirement and replacement of compound insulated switchgears across the network.

Ausgrid has initiated this RIT-D to replace the 11kV switchgear at Concord zone substation in order to identify a preferred option that would ensure Ausgrid is able to satisfy its reliability and performance standards in supplying the Concord load area.

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 non-network option forms all or a significant part of any potential credible option for this RIT-D. It sets out the reasons for Ausgrid's determination, including the methodologies and assumptions used. A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR).

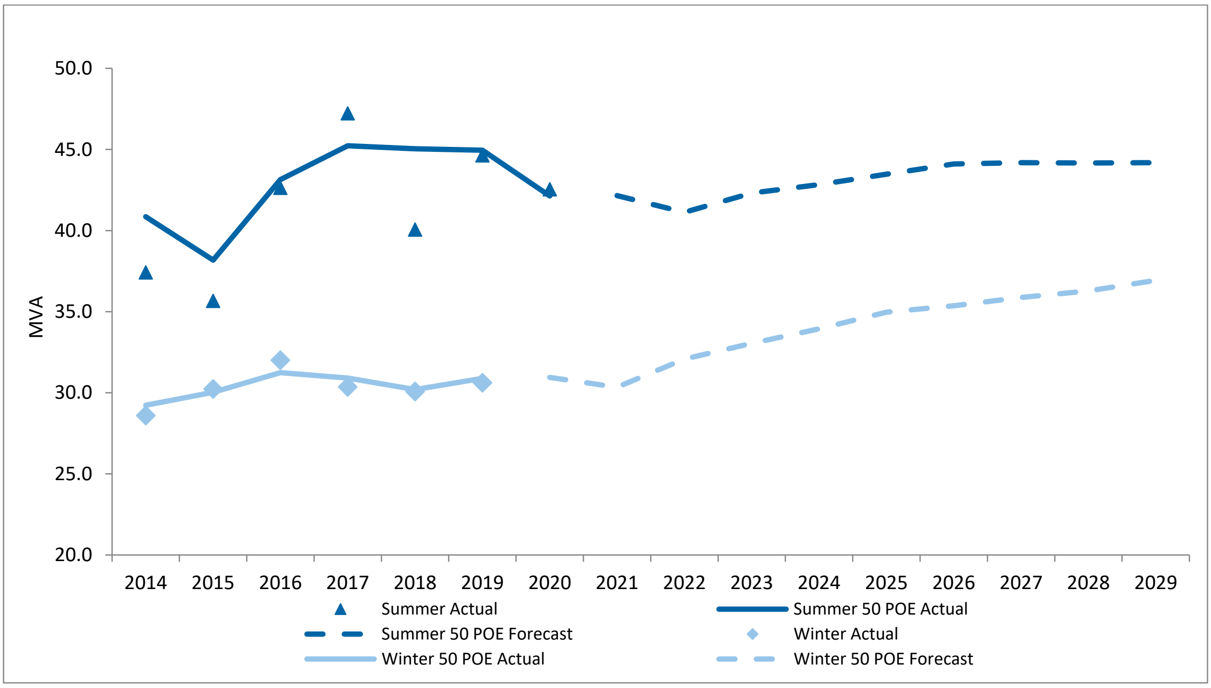
2 Forecast load and capacity

2.1 Demand forecast

Figure 2.1 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 Concord zone substation.

Concord zone substation has a total capacity of 82.3 MVA and a firm capacity of 54.4 MVA. In 2019/20, the maximum demand on the zone substation was 42.5 MVA at 6:00pm AEDT on 23 January 2020. The weather corrected demand at the 50 POE level was 41.1 MVA. The power factor at the time of summer maximum demand was 0.98.

Figure 2.1: Demand forecast at Concord zone substation

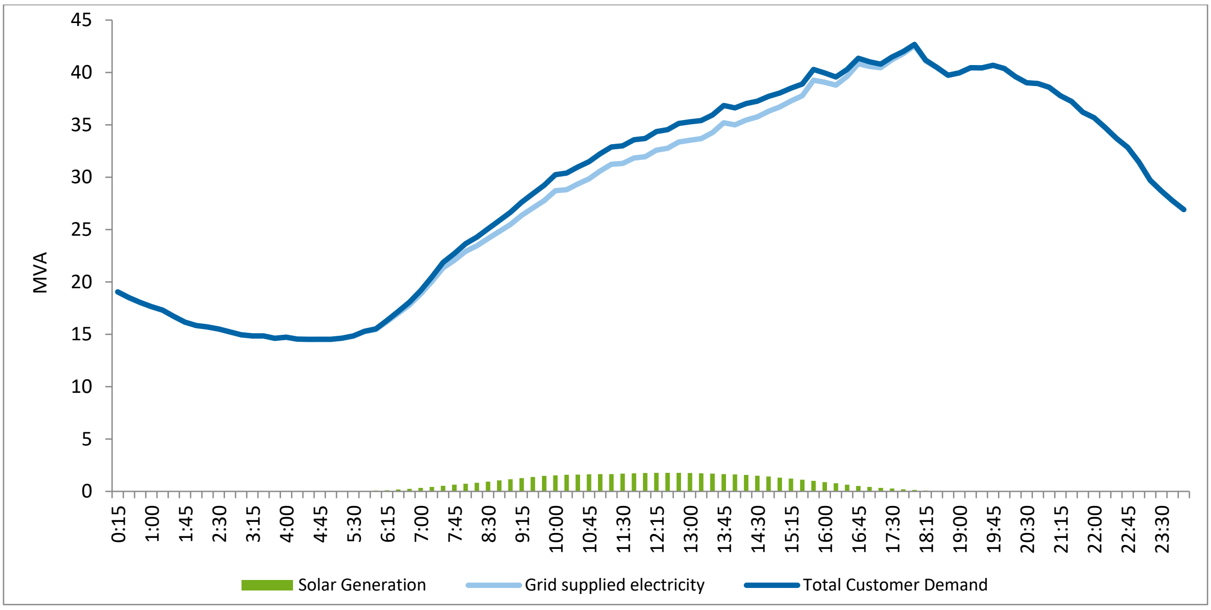


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Concord zone substation has typically occurred in summer between 5:00pm and 6:00pm AEDT.

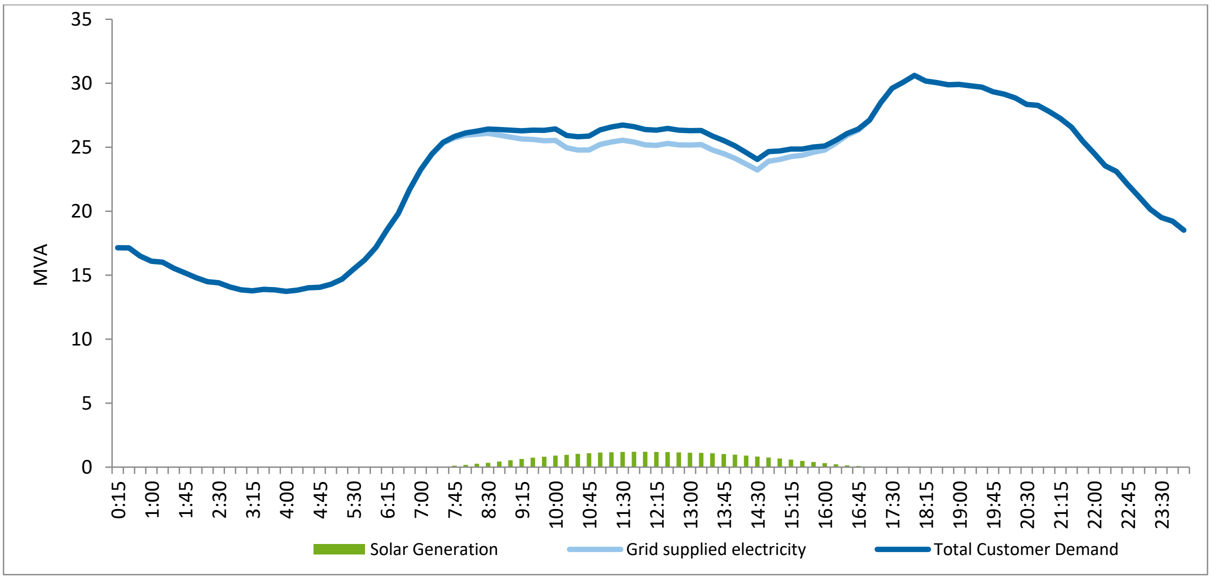
There is a total Solar PV capacity of 2 MW connected to Concord ZS. At the peak time of 6:00pm AEDT on 23 January 2020, these PV systems are estimated to have been generating 0.13 MW. Figure 2.2 below shows the load trace on this day including the contribution from customer solar power systems.

Figure 2.2: Summer peak day demand profile and PV contribution at Concord on 23 January 2020



Over the past 7 years, the time of winter peak has typically occurred between 6:00pm and 6:30pm AEST. At the peak time of 6:00pm AEST on 4 June 2019, the estimated generation from PV systems is 0 MW. Figure 2.3 below shows the load profile for the 4 June 2019 peak demand day including the contribution from customer installed solar power systems.

Figure 2.3: Winter peak demand profile and PV contribution at Concord on 04 June 2019

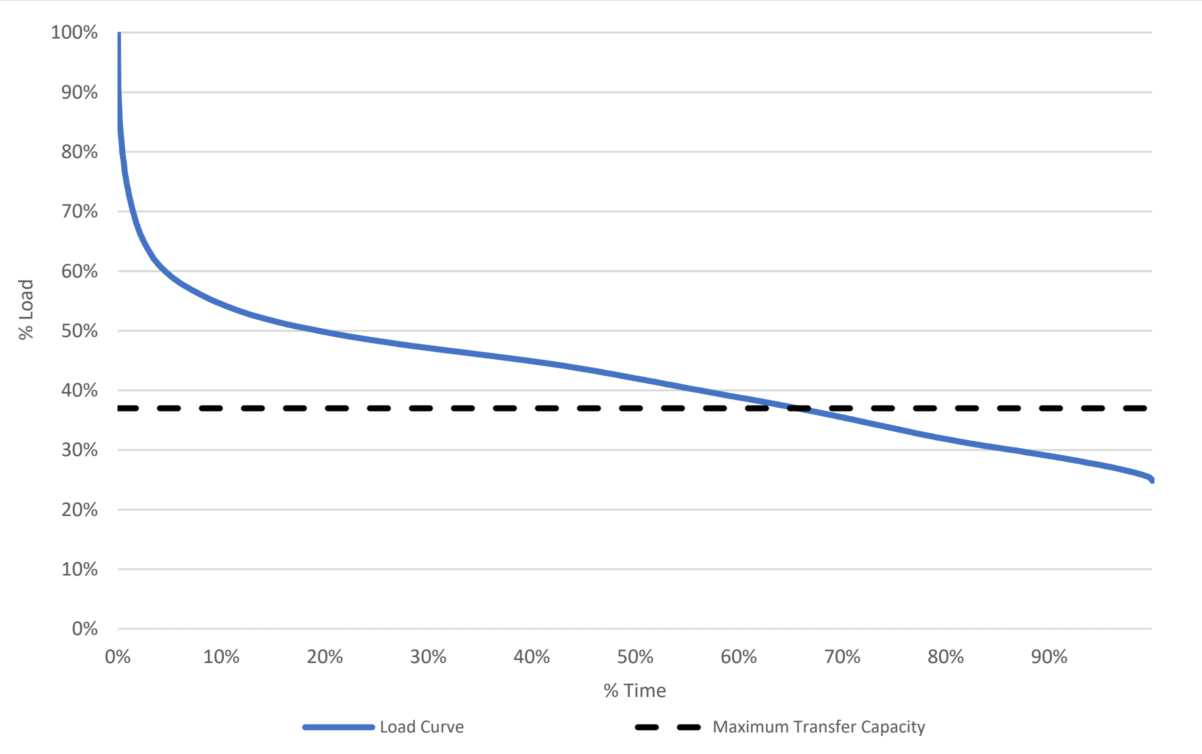


Concord ZS currently has a load transfer capacity of 15.7 MVA or about 37% of the actual maximum 2019/20 summer demand and 51% of actual maximum 2019 winter demand. Based upon the data between May 2017 to April 2020, electricity demand for Concord zone substation exceeds the transfer capacity for around 65% of the time. The load duration curve for the period from May 2017 to April 2020, noting the transfer capacity, is shown below in Figure 2.4.

The load duration curve is derived from Concord zone substation's interval demand data for the period May 2017 to April 2020. The date range is chosen to avoid truncating winter seasons. The load duration curve shows that:

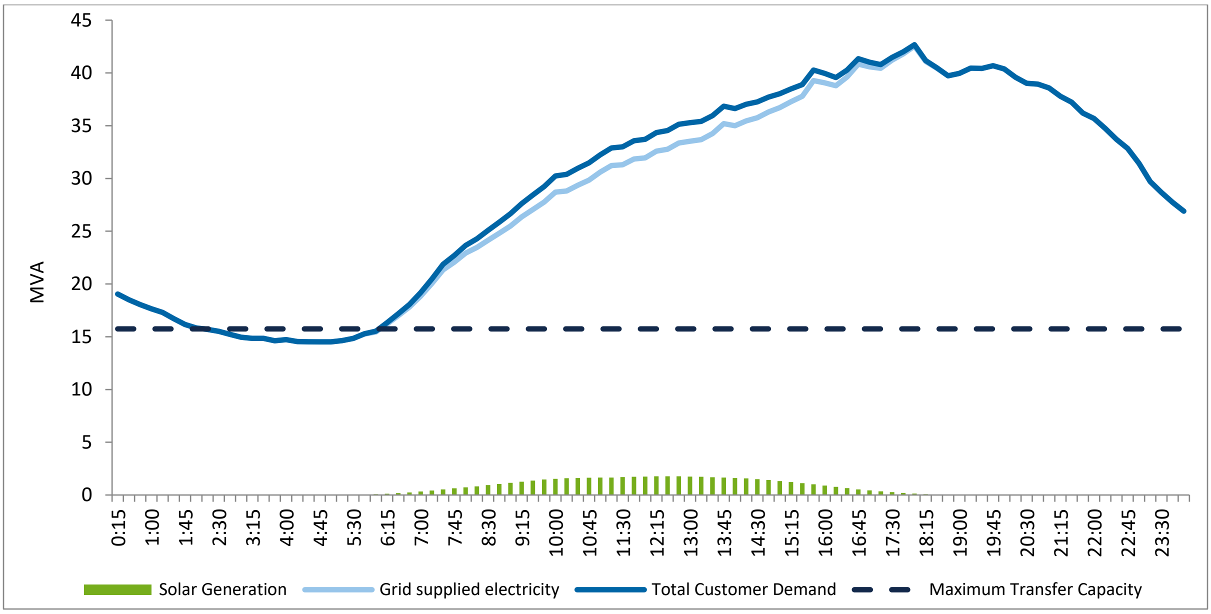
- The top 10% of the load (4.3MW) is exceeded for only 0.1% of the year, or roughly 4 hrs;
- The top 20% of the load (8.5MW) is exceeded for 0.5%of the year, or around 40 hrs.
- The top 27% of the load (11.7MW) is exceeded for 1.1% of the year, or around 100 hrs.
- The top 34% of the load (14.5MW) is exceeded for 2.3% of the year, or around 200 hrs.

Figure 2.4: Concord zone substation load duration curve (May 2017 to April 2020)



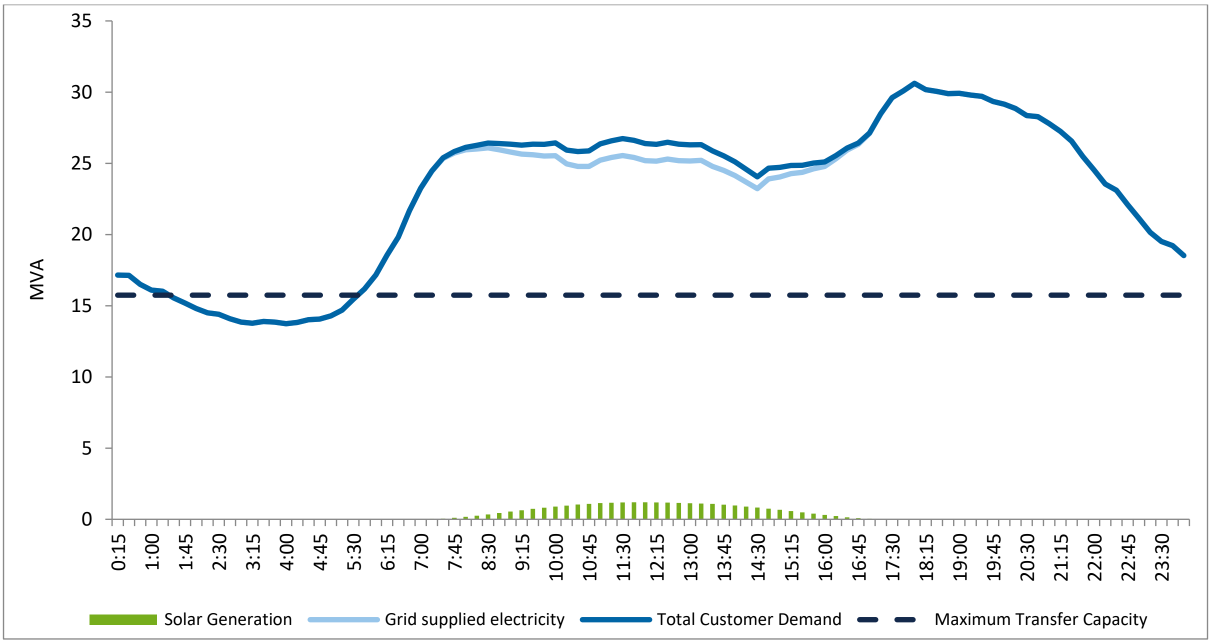
In the event of a network outage on the summer maximum demand day and following realisation of the maximum transfer capacity through network switching, there is a maximum shortfall of around 27 MVA. The shortfall would occur for most of the day as seen in Figure 2.5 below. The duration of the shortfall on other summer days is similar to the peak summer day although reduced in magnitude.

Figure 2.5: Summer maximum demand profile at Concord zone substation with maximum load transfer on 23 January 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 15 MVA. The duration of the shortfall on other winter days is similar to the peak winter day although reduced in magnitude.

Figure 2.6: Winter maximum demand profile at Concord with maximum load transfer on 4 June 2019



2.3 Customer characteristics

Concord zone substations serve a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2019/20 period are as follows:

Table 2.1: Customer characteristics - Concord ZS

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	11,520	1,030	96	12,646
% of Customers	91.1%	8.1%	0.8%	
Annual Consumption (MWh)	51,545	19,869	72,804	144,218
% of Annual Consumption	35.7%	13.8%	50.5%	
Number of Solar Customers	536	84	12	632
% of Solar Customers	85%	13.3%	1.9%	
Average Annual Consumption (MWh)	4.5	19	758	

About 37% of residential customers live in detached homes with an average usage of about 6.5 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.4 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 $2019/20, unless otherwise stated.

Table 3.1: Summary of the credible options considered

Overview	Key components	Estimated capital cost (including decommissioning costs)
Option 1 – Replacement of 11kV switchgear in-situ	Decommission the 11kV compound switchgear and the install new 11kV switchboards, comprising six sections of single bus switchgear and 35 circuit breakers in the same existing switchroom.	$16.7 million
Option 2 – Replacement of 11kV switchgear with a new switchroom	Decommission the 11kV compound switchgear and the install new 11kV switchboards, comprising six sections of single bus switchgear and 35 circuit breakers in a new switchroom at the existing site of Concord zone substation.	$14.3 million

Ausgrid also considered several other options that have not been progressed. In general, these options have not progressed because they were found to be economically infeasible without providing significant additional benefits. The table below summarises Ausgrid's consideration and position on each of these potential options.

Table 3.2: Options considered but not progressed

Option not progressed	Description	Reason why option was not progressed
Construction of a new substation to replace the existing Concord zone substation	This option involves retiring Concord zone substation and establishing a brand new 33/11kV zone substation within the area. To allow for the retirement, all of Concord load will need to be transferred to the new zone substation.	The construction of a new substation is deemed to be economically infeasible, as it is nearly double the cost of the replacement of 11kV switchgear in a new switchroom and provides no significant additional benefits.
Retirement of Concord zone substation via 11kV load transfers to Olympic Park zone substation	This option involves retiring Concord zone substation and transferring all of Concord load to Olympic Park zone substation by installing new 11kV feeders between Olympic Park and Concord zone substations. To provide the required capacity, the existing Olympic Park zone substation will need to be expanded with an additional 3rd transformer and associated 11kV switchgear.	Due to geographical constraints (i.e. area surrounded by waterways and congested roads with subtransmission and distribution assets), this option involves significantly higher costs as well as lower reliability due to longer than existing 11kV connections.

Table 3.3: Summary of the three scenarios investigated

Variable	Baseline scenario	Low benefits scenario	High benefits scenario
Capital cost	100 per cent of capital cost estimate	125 per cent of capital cost estimate	90 per cent of capital cost estimate
Unplanned corrective maintenance cost	100 per cent of baseline corrective maintenance cost estimates	70 per cent of baseline corrective maintenance cost estimates	130 per cent of baseline corrective maintenance cost estimates
Demand	Base	10 per cent below base forecast	15 per cent above base forecast
VCR	$42/kWh	$29/kWh	$55/kWh

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

3.1 Preferred option at this draft stage

Option 2 has been found to be the preferred option, which satisfies the RIT-D and provides a higher net market benefit than option 1. Option 2 involves replacement of the 11kV switchgear in a new 11kV switchroom building to be constructed at Concord zone substation. The proposed scope of works for Option 2 consists of:

- installation of a new switchroom/control room to accommodate the new 11kV switchboard, comprising six sections of single bus switchgear and 35 circuit breakers;
- installation of new 11kV feeders to transfer the existing load from the old to the new switchgear at Concord zone substation; and
- decommissioning of the existing 11kV switchgear, which will be disconnected and removed from site.

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

4 Assessment of 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 Concord zone substation. In 2022/23, the expected commissioning date of the proposed preferred network option, up to 27 MVA of customer demand supplied by Concord zone substation could be lost, after realising available emergency transfer capability.

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 2022/23 for deferral of the network investment.

4.2 Available demand management funds

To identify the available funds for a possible demand management solution, the net NPV benefit for the network option is compared against the net NPV benefit of a deferral of the preferred network option. Where the NPV comparison results in a higher NPV for the possible demand management solution, then there is an amount of available funds for demand management.

Table 4.1 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years for several demand management scenarios. Each scenario:

- Assumes a mix of both short-duration solutions such as demand response and longer-duration solutions such as customer energy efficiency;
- Shows the available funds for demand management if the cost-benefit result is positive; and
- Involves a partial reduction in the risk of loss of supply to customers.

Scenarios involving demand reductions outside of this range are not considered viable as they do not satisfy one or more of the above criteria.

The energy values in Table 4.1 assume short-duration solutions, such as demand response, reduce peak demand for the top 200 hours of the year, with the remainder of the energy shortfall met by longer duration solutions, such as customer energy efficiency. This remaining energy shortfall occurs across a substantial number of hours of the year, as shown in Figures 2.4, 2.5 and 2.6.

This remaining energy shortfall shown in Table 4 is the gap between available capacity and historical load for an entire year, excluding the energy shortfall at peak demand (top 200 hours). Note that while this reflects the approximate energy reduction required to manage this risk using permanent energy efficieny solutions, it is not the volume of energy support that would be required when using controllable solutions such as dispatchable generators. In these instances, the time to repair the network equipment, the time of year when the failure occurs and the customer load would determine the dispatchable energy required to maintain customer supply. Further analysis of dispatchable generators is provided in Section 4.3.5 below.

Table 4.1: Demand management scenarios at Concord zone substation and available DM funds

DM scenario	Demand response (top 200 hrs) (MW)	Remaining energy shortfall after demand response (MWh)	Available funds (present value)		
			1 Yr deferral	2 Yr deferral	3 Yr deferral
1	14.5	7,500	$28,000	NIL	NIL
2	14.5	13,000	$133,000	$29,000	NIL
3	14.5	18,500	$210,000	$194,000	$73,000
4	14.5	24,000	$269,000	$317,000	$270,000

The above figures already account for the 15.7 MVA of load transfer capacity for Concord and assumes this capacity can be fully realised. This is also used for determining the feasibility of demand management solutions as outlined in section 4.3 below.

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 for Concord zone substation. Each of the demand management solutions considered is summarised below. The demand management options are considered against the available funds for a 1-year deferral under Scenario 4 as it offers the highest available funds.

4.3.1 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 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.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical demand response program that reduced peak demand for the top 200 hours. The demand response required for the top 200 hours of demand is 14.5MW. 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.

If it was assumed that the required 14.5MW in demand response was available in the area and could be acquired for an estimated $75-125 per kVA per year for 12 months availability, approximately $1.1-1.8M would be required. The cost of this solution far exceeds the available funds for any of the scenarios and only addresses the energy requirements for the top 200 hours. In addition, funding will also be required to address the remaining energy shortfall after the demand response, which is significantly larger than the energy shortfall for the top 200 hours. We consider there is insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.2 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 around 0.4 MVA at Concord zone substation. At a projected demand management cost of about $25-50 per kVA, the estimated cost to achieve commercial potential is about $10k – $20k.

Based on typical annual commercial operation hours, this solution would contribute approximately 783 MWh of the target energy reduction, which would only meet approximately 3-10% of the remaining energy shortfall after the initial demand response, for the DM scenarios in Table 4.1. This solution appears cost-effective, but on its own does not fulfil the target energy 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 an assessment of their viability is provided below.

4.3.3 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 overload conditions. Analysis of interval data for Concord zone substation shows that while solar generation is partially coincident with the energy shortfall, it offers no reduction in load during non-solar hours and negligible reduction during summer and winter peak demand periods. As the shortfall is across solar and non-solar hours in the year, a non-dispatchable solar power system would offer no support outside of daylight 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, which is only available for DM Scenario 4. As solar power system generation is subject to hourly, seasonal and cloud cover variation, an example of 1 MW solar array is estimated to generate up to 1.4GWh annually, which would only meet approximately 8-20% of the remaining energy shortfall after the initial demand response, for the DM scenarios outlined in Table 4.1.

This indicates that customer solar power system would address only a small portion of the energy shortfall, and a very small portion of the peak demand shortfall, at a cost that is 78% - 92% of the available funds for DM Scenario 4. For all other scenarios, the cost exceeds available funds. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.4 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 Figures 2.4, 2.5 and 2.6.

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 total customer investment required might encourage additional customer take-up of energy efficiency improvements. With an incentive of about $200-500 per kVA and based on annual commercial operation hours, the following energy reduction could be achieved using 100% of the available funds for each scenario.

Table 4.2: Potential energy reduction for energy efficiency programs

DM scenario	Energy reduction (MWh)	Energy reduction as a percentage of remaining energy shortfall after demand response
1	75 - 188	1-3%
2	358 - 894	3-7%
3	564 - 1,411	3-8%
4	852 - 2,130	4-9%

As can be seen in Table 4.2, energy efficiency improvements would meet less than 10% of the energy shortfall after demand response. Consequently, we consider there is insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.5 Dispatchable generators

Dispatchable generators offer a reliable and relatively mature solution that can be deployed quickly at almost any network location to provide generation support which can be short term or longer term. As a controllable type of solution, consideration is given to the maximum duration of support that may be required.

In the event of major equipment failure at Concord zone substation, it may take up to 17 days to repair or replace faulty or damaged equipment and fully restore grid supply to customers, meaning that controllable types of solutions such as dispatchable generators may be required to provide network support for this duration. The corresponding required volume of support would need to consider this repair time, time of year and the energy shortfall, recognising that a major equipment failure could occur at any time of the year.

In assessing the required duration of support, we have averaged the annual shortfall over the repair window resulting to 53MWh/day of support but would vary significantly depending upon the time of year the outage occurred. Based on an estimated cost structure comprising availability and energy volume elements, maximum available DM funds would only contribute around 25% of the shortfall in the repair window. We consider there is insufficient funds available for this solution to be part of a cost-effective demand management 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 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. We therefore consider there is insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

5 Conclusion

Based on the demand management options considered in Section 5, 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.

Ausgrid