# Managing asset risks in the St George network area

## NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

SEPTEMBER 2018

Ausgrid

# Managing asset risks in the St George network area

Notice on screening for non-network options – 18 September 2018

## Title of Contents

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# 1 Introduction

The distribution network serving the St George area is largely supplied from one subtransmission substation (STS), which is located at Peakhurst. This STS was commissioned in 1964 and has asset condition and safety concerns stemming from obsolete 33kV switchgear, located in a switchroom building that is non-compliant with contemporary Building Code of Australia (BCA) standards and without adequate segregation in the event of equipment failure.

The St George network area extends west from Arncliffe and Sans Souci inland to Peakhurst. It includes low and high density residential developments and commercial areas. The existing distribution network in the St George area is served from three 132/11kV zone substations and five 33/11kV zone substations supplied from Peakhurst STS. The 33/11kV zone substations supplied from Peakhurst are Arncliffe, Blakehurst, Mortdale, Riverwood and Sans Souci zone substations.

Peakhurst STS is equipped with three 132/33kV 120MVA transformers (two of which are in service currently, while the third is on standby) and four sections of 33kV switchgear. Peakhurst STS has a firm rating capacity of 233MVA and a recent peak load (summer driven) of 158MVA.

While Arncliffe substation in the St George area will be retired in coming years, which will reduce Peakhurst STS load from 2019 onwards, there is an enduring need for the Peakhurst STS and there are fundamental asset condition issues identified. Specifically, the 33kV switchroom and control buildings are in poor condition and most of the 33kV switchgear equipment is at end of its service life.

Despite the reduced load coming into effect from 2019, there are fundamental asset condition issues that have been identified in the following assets at Peakhurst – specifically:

- The 33kV switchroom and control buildings are in poor condition, without adequate fire segregation in the event of a failure; and
- The 33kV equipment (wall bushings, oil circuit breakers, isolators & earth switches) have degraded insulation quality, which imposes a significant safety risk in the event of failure.

If left unaddressed, these assets are likely to become less reliable, which could expose Ausgrid’s staff and general public to increasing safety risks and also expose customers in the area to risks that exceed allowable levels under the applicable reliability standards. Ausgrid considers that reliability correction action is required for Peakhurst STS to comply with its electricity distribution license reliability and performance standards.

Rule changes to the National Electricity Rules (NER) in July 2017 have meant that replacement capital expenditure, such as the one proposed in this DPAR, are now subject to the RIT-D. Accordingly, Ausgrid has initiated this RIT-D for the Peakhurst STS replacement project in order to identify a preferred option that would ensure Ausgrid is able to satisfy its reliability and performance standards in supplying the St George network area.

A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR) for managing asset risks in the St George area.

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.

# 2 Forecast load and capacity

## 2.1 Load forecast

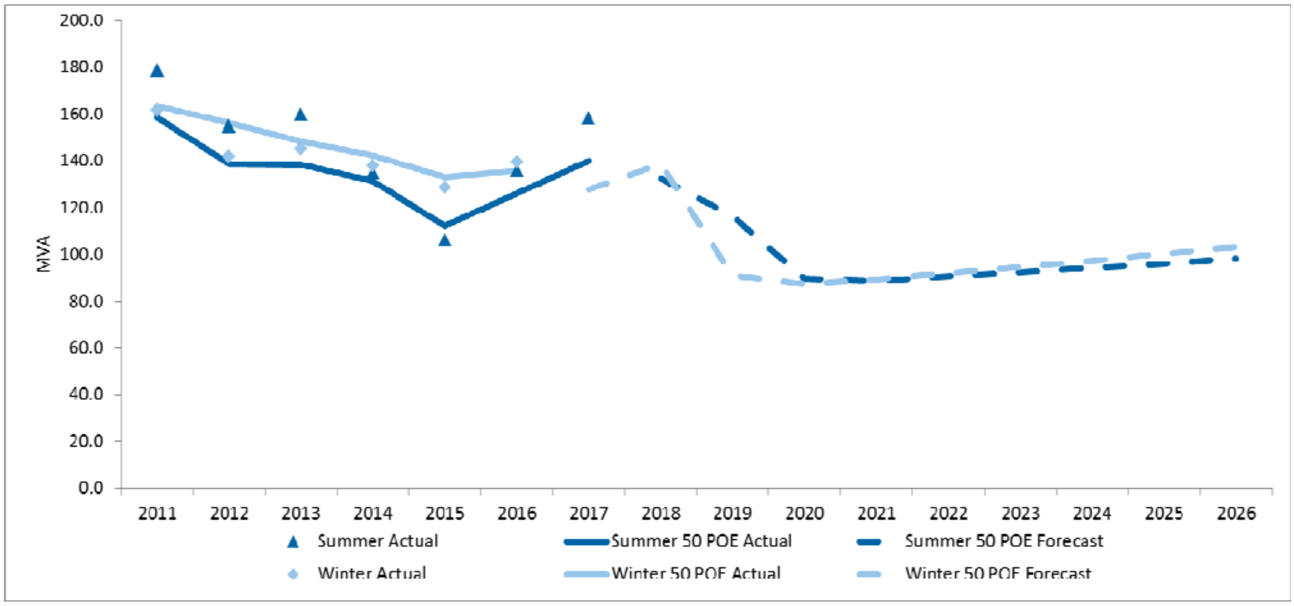
Figure 1 below shows the historical actual demand, the 50% Probability of Exceedance level (50 POE) weather corrected historical actual demand and the 50 POE forecast demand for both winter and summer for Peakhurst subtransmission substation (STS).

The Peakhurst STS has a total capacity of 349.8 MVA and a firm capacity of 233.2 MVA. In 2016/17, the maximum demand on the subtransmission substation was 157.9 MVA at 6:15pm AEDT on 11 February 2017. The weather corrected demand at the 50 POE level was 140 MVA. The power factor at the time of summer maximum demand was 0.98.

In the past seven years, maximum demand has occurred in summer in three years and winter in four years. When maximum demand has occurred in the summer season, the maximum demand has occurred between 5:45pm and 9:00pm AEDT. When maximum demand has occurred in the winter season, the maximum demand has occurred between 6:45pm and 7:00pm AEST.

As shown in Figure 1 below, maximum demand is forecast to be 90.7 MVA in Summer 2021/22 and 92.1 MVA by Winter 2022.

**Figure 1 – Demand forecast at Peakhurst STS**



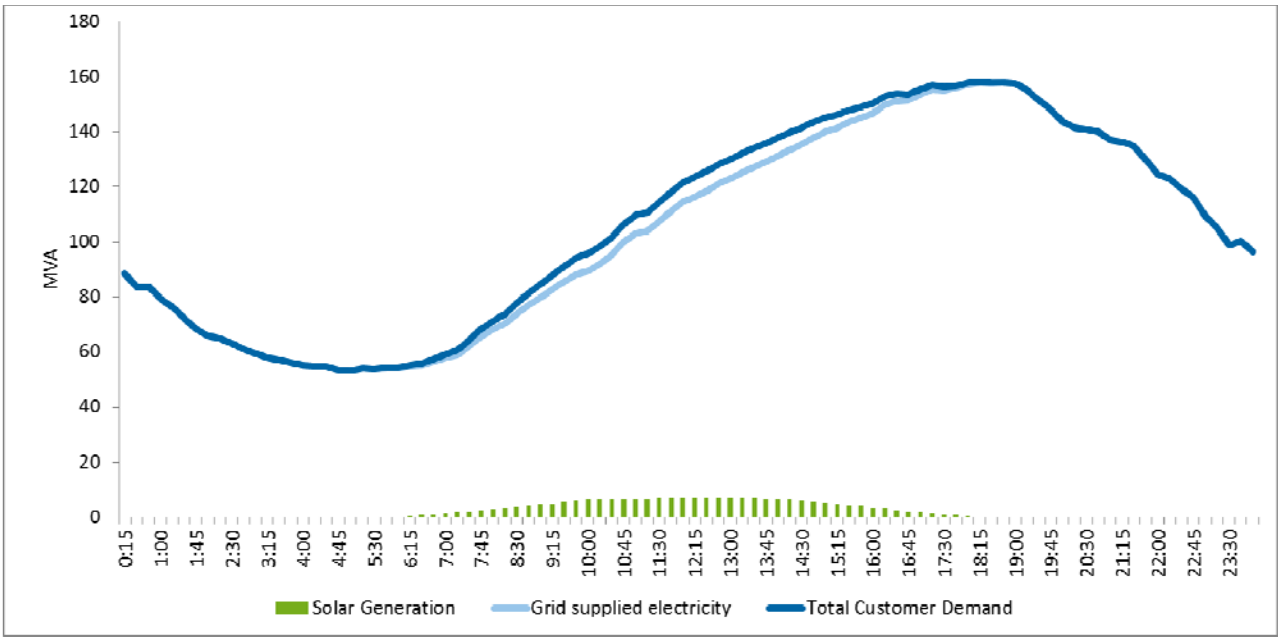

## 2.2 Pattern of use

Summer peak electricity demand at Peakhurst STS occurs on hotter days driven predominantly by demand from residential customers.

Over the past 7 years, the time of summer peak demand has occurred between 5:45pm and 9:00pm AEDT. As noted above, the 2016/17 summer maximum demand of 157.9 MVA occurred at 6:15pm AEDT on 11 February 2017.

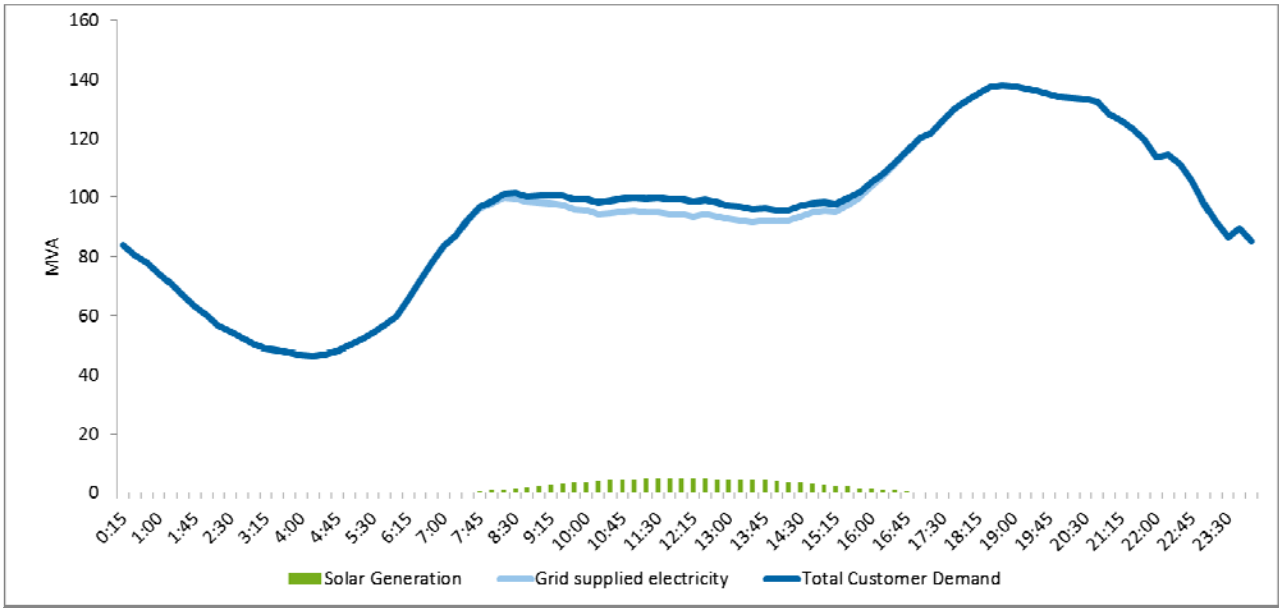
At this time, there was a total capacity of about 10.8 MW of solar PV connected to the Peakhurst STS. At the peak time of 6:15pm AEDT on 11 February 2017, these PV systems are estimated to have supplied 0.3 MW of the customer load. Figure 2 below shows the load profile for the 11 February 2017 maximum demand day including the estimated contribution from customer installed solar power systems.

**Figure 2 – Summer maximum demand profile at Peakhurst STS (11 February 2017)**




Over the past 7 years, the time of winter peak has occurred between 6:45pm and 7:00pm AEST. The 2016 winter maximum demand of 139.6 MW occurred at 6:45pm AEST on 27 June 2016. Figure 3 below shows the load profile for the 27 June 2016 winter peak demand day including the contribution from customer installed solar power systems. At the peak time of 6:45pm AEST, it is estimated that these PV systems did not offset any customer load.

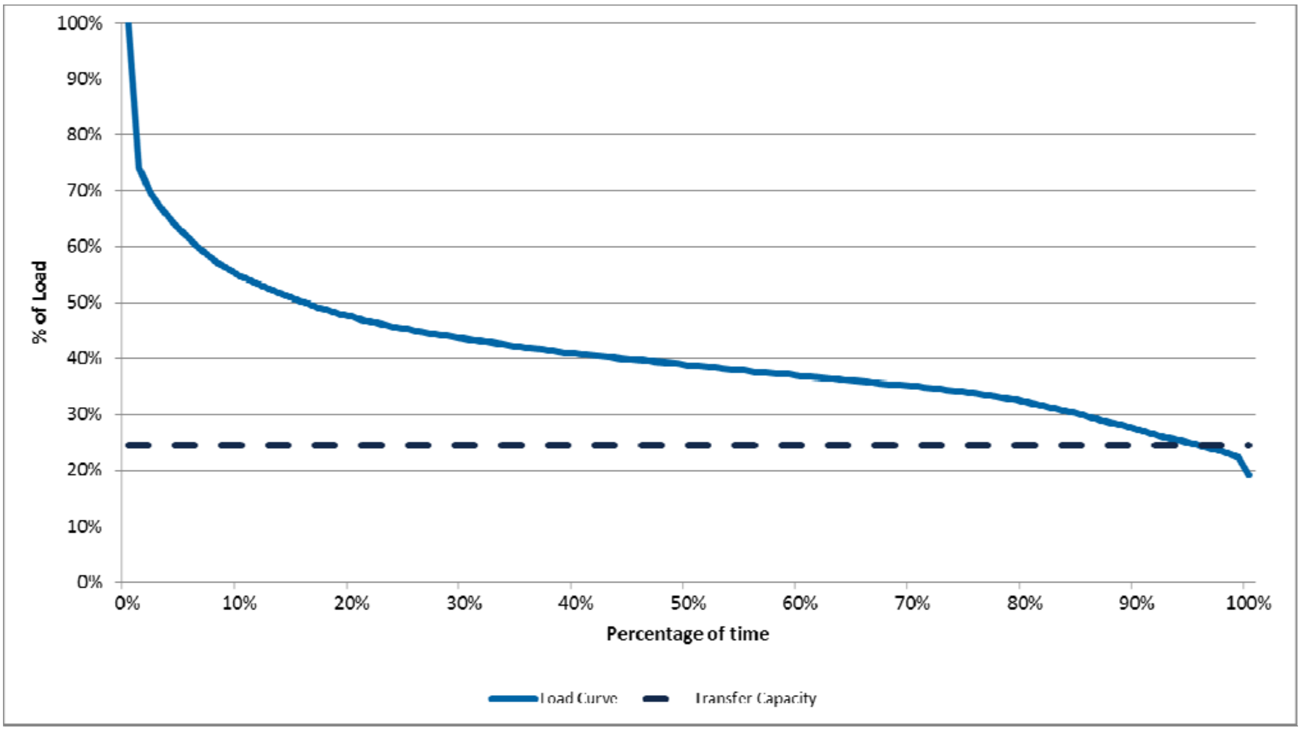
**Figure 3 – Winter maximum demand profile at Peakhurst STS (27 June 2016)**




## 2.3 Forecast pattern of use (2021/22)

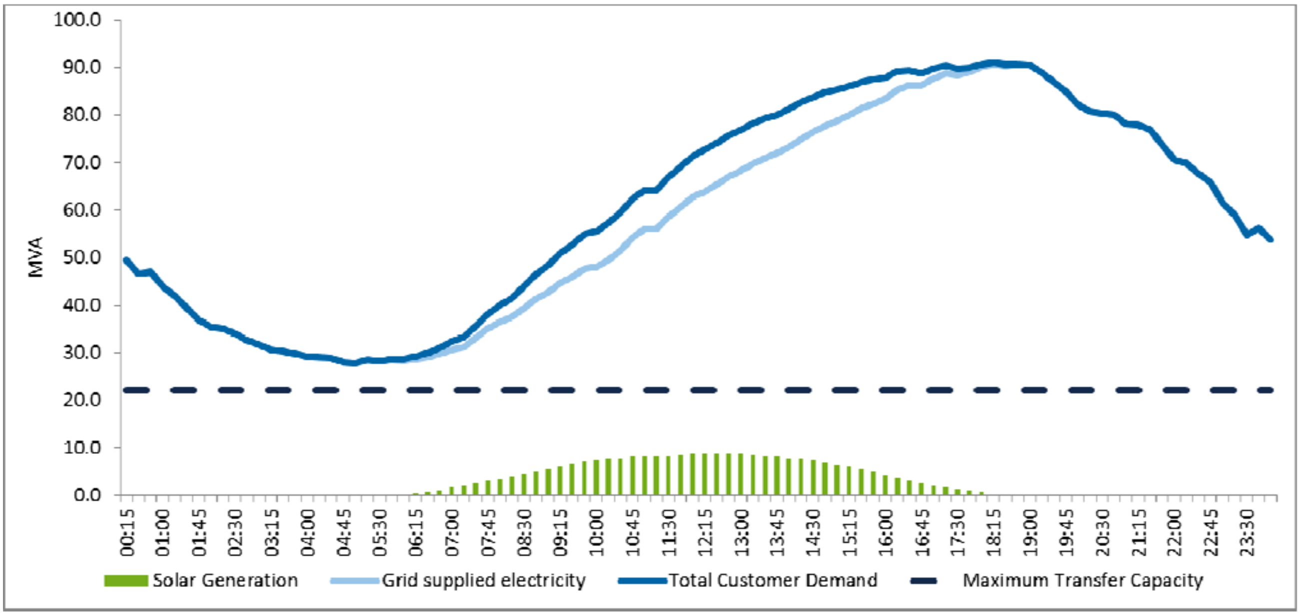
The Draft Project Assessment Report identified a need date for the investment of 2021/22 and the network project commissioning date is estimated to be by December 2021. For a deferral of the network investment, a demand management solution must be in place in time for summer 2021/22. Peakhurst STS is estimated to have a remaining emergency load transfer capacity of about 22 MVA or about 24% of the forecast 2021/22 maximum summer demand. and 25% of the forecast 2022 maximum winter demand. The load duration curve for the 2021/22 period, noting the transfer capacity, is shown below in Figure 4.

**Figure 4 – Forecast 2021/22 Load Duration Curve at Peakhurst STS**



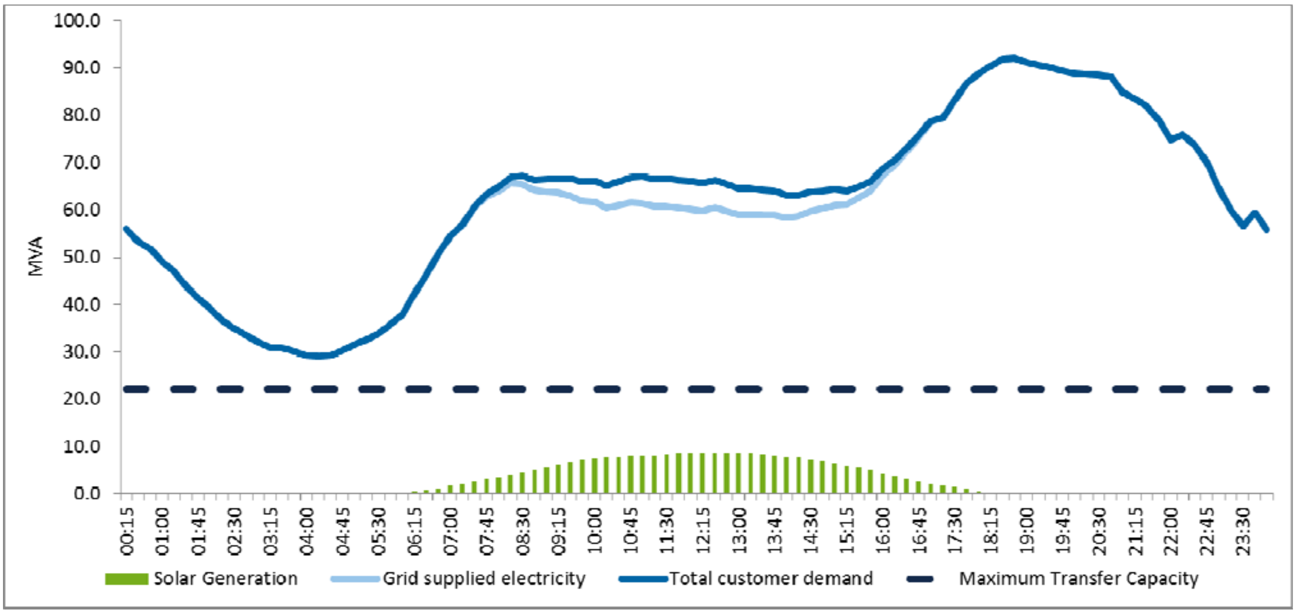

In the event of a network outage, and on a maximum summer peak demand day, after use of the maximum transfer capacity in an emergency switching of the network, there is a shortfall of network supply for the entire day. See Figure 5.

**Figure 5 – Forecast 2021/22 Summer maximum demand profile at Peakhurst STS**



In the event of a network outage, and on a maximum winter peak demand day, after use of the maximum transfer capacity in an emergency switching of the network, there is a shortfall of network supply for the entire day. See Figure 6.

**Figure 6 – Forecast 2022 Winter maximum demand profile at Peakhurst STS**




## 2.4 Customer characteristics

Peakhurst STS currently serves a mixture of residential and non-residential customers. Excluding the customers currently served by Arncliffe and Rockdale zone substations, over 93.3% of annual electricity consumption is from residential customers. A breakdown of the customer characteristics is as follows:

**Table 1 – Customer characteristics – Peakhurst STS (excluding Arncliffe ZS)**

| Item | Residential | Small Non-Residential | Large Non-Residential | Total |
|---|---|---|---|---|
| Number of Customers | 47,893 | 3,345 | 127 | 51,365 |
| % of Customers | 93.2% | 6.5% | 0.2% | |
| Annual Consumption (MWh) | 274,297 | 53,348 | 62,822 | 390,467 |
| % of Annual Consumption | 70.2% | 13.7% | 16.1% | |
| Number of Solar Customers | 2,791 | 94 | 2 | 2,887 |
| % of Solar Customers | 96.7% | 3.3% | 0.1% | |
| Average Annual Consumption (MWh per customer) | 5.7 | 16 | 495 | |

About 54% of residential customers live in detached homes with an average usage of about 7.2 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 4.0 MWh per year.

# 3 Proposed preferred network option

Ausgrid has identified two network options:

- Option 1: Brownfield  development - refurbish the 33kV switchgear building and roof in situ, and like for like replacement of each 33kV circuit breaker and associated control and protection; or
- Option 2; Greenfield development – construct a new 33kV switchgear building equipped with new 33kV fixed pattern switchgear and associated control and protection, then retire existing 33kV switchgear building and associated 33kV bulk oil circuit breakers and associated control and protection.

The two credible network options are summarised in the table below. All costs in this section are in 2018/19 dollars, unless otherwise stated.

### Table 2 – Summary of the credible options considered

| Network option | Key components | Estimated capital cost |
|---|---|---|
| Option 1 – Brownfield development | • resolution of the 33kV building issues at Peakhurst STS.<br>• repair of the 33kV switchroom roofs and replacement of the roof sheeting in the 33kV circuit breaker bays and over the 33kV busbar gallery.<br>• “like-for-like” replacement of 33kV bulk oil circuit breakers, 33kV Essantee isolators and 33kV feeder control and protection equipment. | $22.4 million +<br>0.5 million (decommissioning) |
| Option 2 – Greenfield development | • construction of a new 33kV switchroom.<br>• installation of new 33kV switchgear.<br>• retirement of the existing 33kV bulk oil circuit breakers and associated control and protection.<br>• demolition of existing 33kV switchgear buildings. | $20.3 million +<br>$2.0 million (decommissioning) |

One further network option was considered in addition to those set out in the table above, which involves retirement of the 33kV portion of Peakhurst STS, but was found to be non-credible.

Ausgrid has elected to assess the two network options against 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 potential market benefits.

A summary of the key variables in each scenario is provided in the Table 3 following.

**Table 3 – Summary of the three scenarios investigated**

| Variable | Scenario 1 – low benefits | Scenario 2 – baseline | Scenario 3 – high benefits |
|---|---|---|---|
| Capital cost | 125 per cent of capital cost estimate | 100 per cent of capital cost estimate | 75 per cent of capital cost estimate |
| Demand | Lower than expected load growth | Expected load growth | Higher than expected load growth |
| VCR | $29/kWh<br>(30 per cent lower than the central, AEMO-derived estimate) | $41/kWh<br>(Derived from the AEMO VCR estimates) | $53/kWh<br>(30 per cent higher than the central, AEMO-derived estimate) |
| Safety risk cost | 70 per cent of baseline estimate | 100 per cent of baseline estimate | 130 per cent of baseline estimate |
| Unplanned corrective maintenance cost | 70 per cent of baseline estimate | 100 per cent of baseline estimate | 130 per cent of baseline estimate |

## Preferred option at this draft stage

Option 2 has been found to be the preferred network option, which satisfies the RIT-D. It involves the construction of a new 33kV switchroom, installation of new 33kV switchgear and the retirement of the existing 33kV switchgear buildings at Peakhurst STS.

The estimated cost of this option is approximately $20.3 million with further $2.0 million for decommissioning costs. Ausgrid assumes the greenfield development would commence in 2018/19 with the replacement scheduled to be commissioned in 2021/22 and subsequent decommissioning of the aged network assets in 2022/23. Once the replacement is complete, operating costs are expected to be approximately $100,000 per annum (around 0.5 per cent of capital expenditure).

# 4 Assessment of non-network solutions

## 4.1 Required demand management characteristics

As noted in Section 2.3, in the event of a network outage, the supply shortfall from Peakhurst in 2021/22 is about 70 MW in summer and winter. As the driver for this replacement investment is largely the need to manage safety risks at the site (90% of risk value in 2021/22), a viable demand management solution must be capable of reducing the load on Peakhurst STS so as to cost effectively reduce the safety risk. And 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 2021/22 for deferral of the network investment.

An assessment of the network safety risks shows that a 10% reduction in the safety risk is possible with a 15 MW reduction in load at Mortdale ZS only. This would allow the retirement and de-energisation of one transformer at Mortdale ZS and the associated network equipment at Mortdale ZS and Peakhurst STS. The forecast maximum demand at Mortdale ZS in 2021/22 is 44 MVA, or a minimum required 34% reduction in maximum demand to allow the retirement of the network equipment.

Figure 7 and 8 below detail the time intervals and hours per month where a demand reduction is required to achieve the 15 MW reduction.

**Figure 7 – Number of days per time interval where demand exceeds reduced capacity at Mortdale**

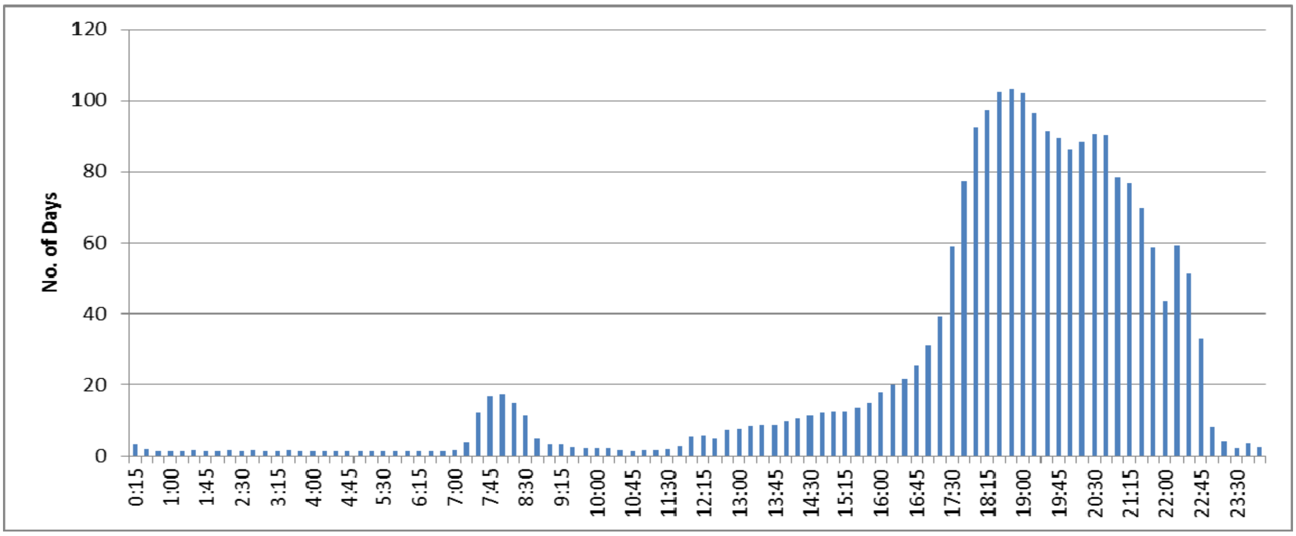
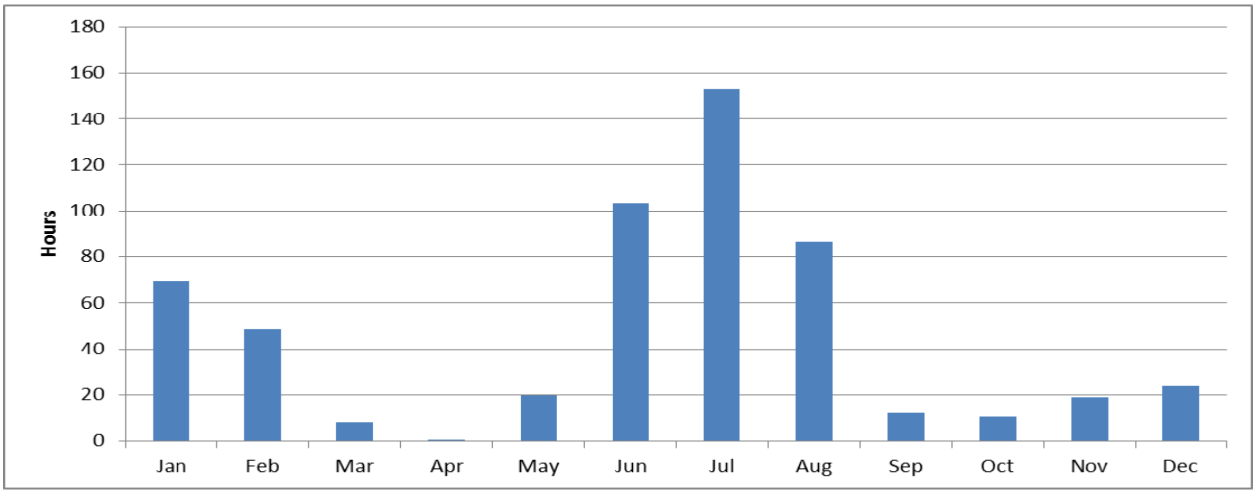



**Figure 8 – Number of hours per month where demand exceeds reduced capacity at Mortdale**



Further reductions in customer load from any of the four zone substations (Mortdale ZS, Riverwood ZS, San Souci ZS and Blakehurst ZS) would reduce the energy at risk, but they would not further affect the safety risk at Peakhurst STS. As the benefit from a permanent or temporary reduction in customer load is associated with the energy at risk and not the demand at risk, there is a lower value available for reductions in peak demand that occurs on only a few hours of the year.

Note that due to the network configuration, only the removal of the entire 92 MW (2021/22) of load from Peakhurst STS would result in a further reduction in the safety risk. In this instance, Penshurst STS could be retired with no further network need. However, the removal of the entire load using demand management solutions is not considered viable.

## 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 with the net NPV benefit of a deferral of the preferred network option. For the purposes of this assessment, we have assumed that the deferral is due principally to a 10% reduction in the safety risk from a 34% reduction in the maximum demand at Mortdale ZS. At this stage, we have not assessed whether this level of reduction in safety risk is sufficient to warrant deferral of the network need.

For the purposes of this assessment, we have assumed that 67% of the reduction is from demand response at peak times only (60 hours per year) and 33% from broader energy efficiency type solutions which impact a much larger number of hours coincident with the shortfall requirement.

**Table 4 – Minimum required demand reductions at Mortdale ZS**

| Required Demand reduction (MW) | Available funds | | |
|---|---|---|---|
| | 1 Yr deferral | 2 Yr deferral | 3 Yr deferral |
| 15 | $0.14m | $0.33m | $0.49m |

Further reductions in customer load from any of the four zone substations (Mortdale ZS, Riverwood ZS, San Souci ZS and Blakehurst ZS) would offer additional incremental funds for a demand management solution as per Table 5 below. Note that as the available funds vary by the number of hours the demand reductions are effective, we have provided an estimate below which reflects both typical demand response type solutions that target the 60 hours when demand is highest and energy efficiency type solutions which can deliver 2-4,000 hours of savings per kW of reduction.

**Table 5 – Estimated funds available for incremental demand reductions**

| Deferral year | Funds available from Demand response ($/kW) | Funds available from broader load reductions ($/kW) |
|---|---|---|
| 1 | $0.05 | $0.57 |
| 2 | $0.08 | $0.81 |
| 3 | $0.11 | $1.29 |

## 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 Peakhurst STS. 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 3475 non-residential customers connected to Peakhurst STS, about 125 are on a kVA demand tariff. Analysis of customer interval data indicates a technical potential of about 605kVA. Commercial potential is likely to be 340 kVA, with about 150kVA possible at Mortdale ZS. At a projected cost of about $25-50 per kVA, this solution might be cost effective, but would contribute to only about 1% of the 15 MW demand reduction required at Mortdale ZS in 2021/22.

### 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 Peakhurst STS show that while solar generation is largely coincident with the energy shortfall, this is principally due to the very large shortfall in energy. Due to the very modest budget available for managing load at risk, this solution is not considered viable.

For the 15 MW peak reduction required at Mortdale ZS, solar generation is largely non-coincident (refer Figures 7 and 8); with peak demand typically occurring between 6pm and 9pm in summer and winter.

### 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. 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.

Assuming this higher rate of uptake by customers indicates an impact at Mortdale ZS of about 0.4 MW at peak in 2021/22 or about 2.5% of the 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 only address about 2% of the demand reduction requirement in 2021/22.

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 $0.36m in 2021/22 or about 75% of the available funds for a three year deferral.

While this option is technically feasible and might offer 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

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 could address peak demand at Mortdale ZS for about 60 hours per year.

Past practice show that costs for traditional demand response from commercial and industrial (C&I) customers is in the range of $75-150 per kW for 30-50 hours of dispatch and 3-4 months availability. But due to the heavy weighting of residential customers served by Mortdale ZS, there is likely to be a limited demand response potential available from C&I customers. Costs for residential demand response are typically estimated to be much higher, with an estimated range of $100-200 per kW for acquisition and $50-150 per kW per year dispatch.

For the purposes of the budget cost estimate, we have assumed that C&I customers are able to provide between 1/3 and 2/3 of the demand reduction required.

**Table 6 – Dispatchable network support required at Mortdale ZS**

| Deferral period | Deferral Year | Peak Load Reduction required (MW) | Estimated cost |
|---|---|---|---|
| 1 year | 2021/22 | 10 | $1.0-2.8m |
| 2 year | 2022/23 | 10 | $1.7-3.3m |
| 3 year | 2023/24 | 10 | $2.3-4.2m |

On average, the estimated cost for 10 MW of demand response is many times larger than the available funds for the entire 15 MW demand reduction required at Mortdale ZS.

Note also that at this stage, the availability, customer willingness to contract and actual cost for the demand response capability noted in Table 6 is an estimate for the purposes of the screening test only.

### 4.3.5 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.

Ausgrid