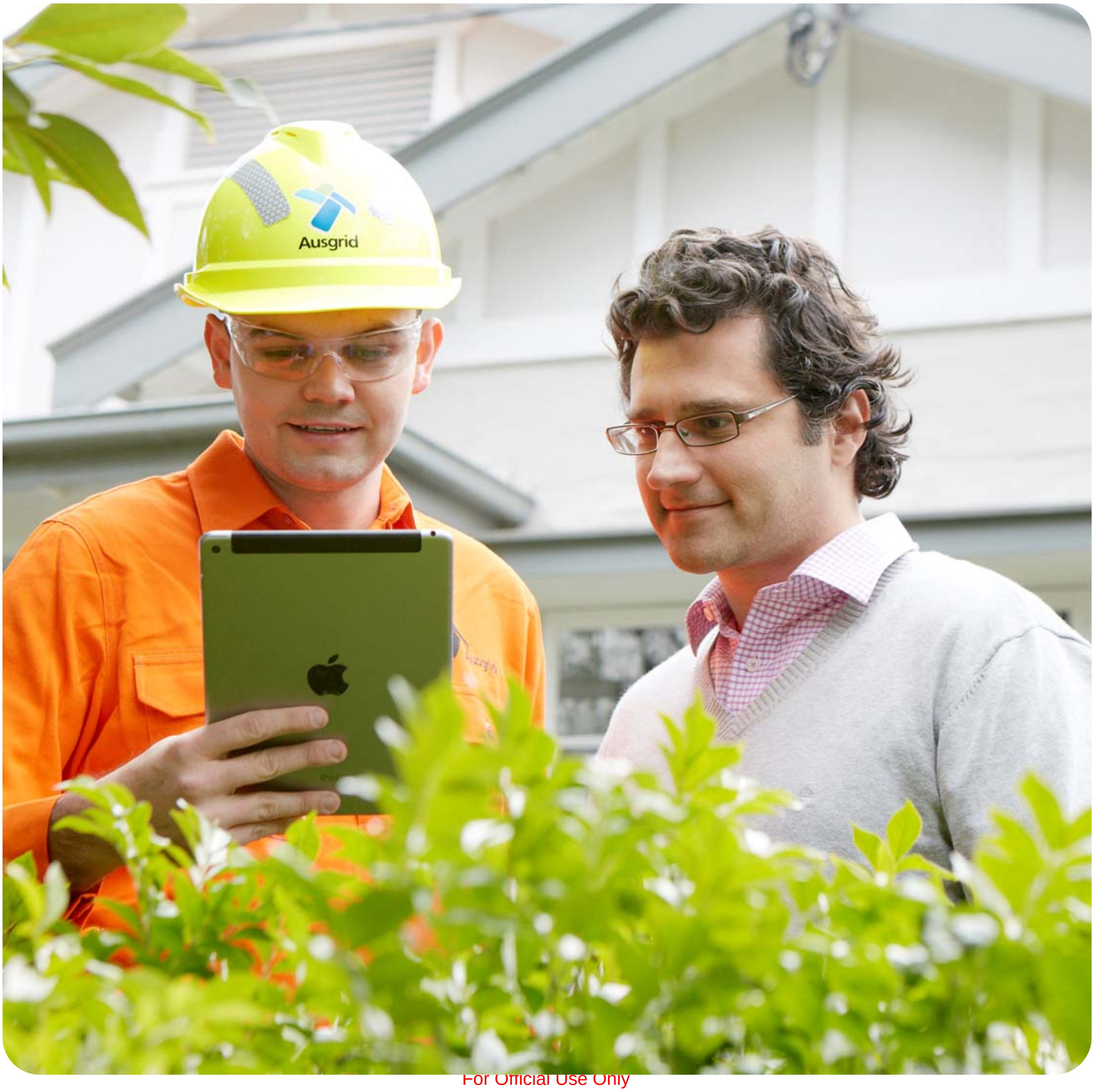
Addressing reliability requirements in the Inner West

Notice on screening for non-network options

February 2018



Addressing reliability requirements in the Inner West area

Notice on screening for non-network options – February 2018

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1 Introduction

The underground electricity distribution lines (‘feeders’) supplying the 33 kV Auburn zone substation and the 33 kV Lidcombe zone substation were commissioned in the 1940s and 1950s, and are now reaching, or past, the end of their technical lives. These feeders utilise a mix of gas pressured cables and HSL cables, which are now considered obsolete and dated technologies, respectively. The implication of these assets becoming less reliable is that it exposes Ausgrid’s customers in the Inner West network area to a level of involuntary load shedding that exceed allowable levels under reliability standards applicable to Ausgrid.

Changes to the National Electricity Rules (NER) in July 2017 have meant that the replacement plan for ageing feeders in the Inner West network area is now subject to the RIT-D. Ausgrid’s planning for the ageing asset, and consequent reliability, issues identified for the Inner West began in 2013. In particular, Ausgrid identified the need to replace the feeders supplying the Auburn and Lidcombe zone substations as part of formulating its Inner West Area Plan and asset management strategy for sub-transmission feeders. In addition, Ausgrid worked with Endeavour Energy to identify a preferred solution that makes use of spare capacity on the Endeavour network following closure of a Shell Australia oil refinery at Clyde in Western Sydney.

Ausgrid considers these joint planning efforts identified the most efficient solution across the respective networks as a whole. In particular, this solution was found to come at a significantly lower cost than rebuilding the existing feeders on a ‘like-for-like’ basis.

Accordingly, Ausgrid has initiated this RIT-D for replacing ageing feeders supplying the Auburn and Lidcombe zone substations in order to investigate and consult on options to ensure Ausgrid is able to satisfy the reliability and performance standards that it is obliged to meet.

A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR) for addressing reliability requirements in the Inner West.

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

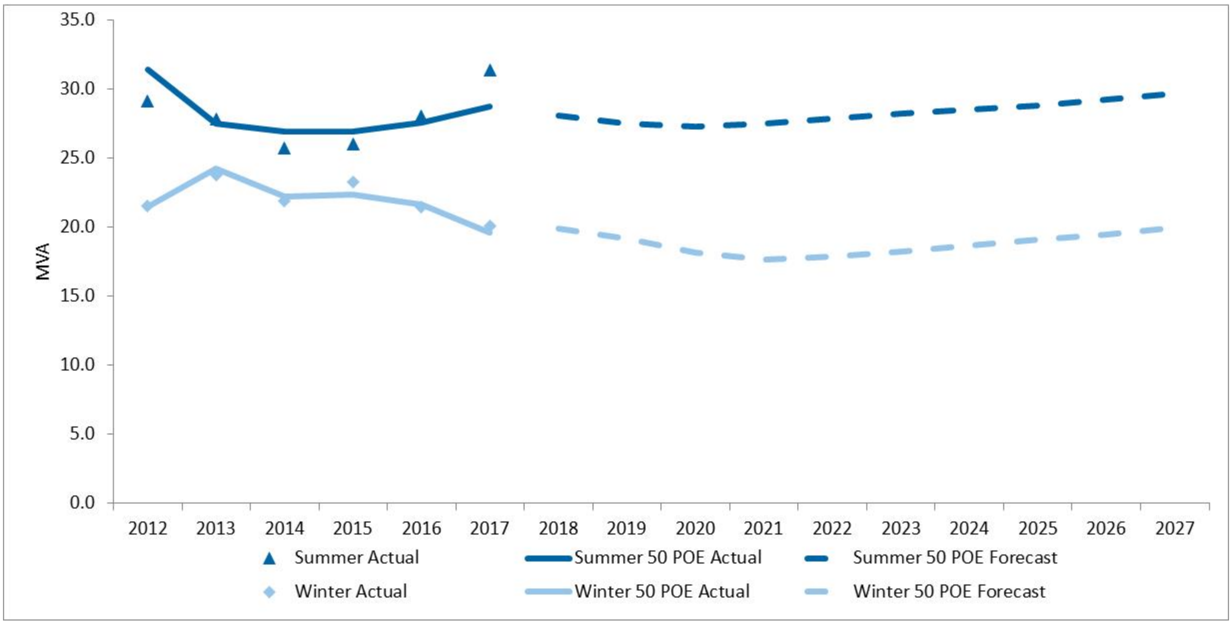
Figure 1 and Figure 2 below show the historical actual demand, the 50% Probability of Exceedance level (50 POE) weather corrected historical actual demand and the 50 POE forecast demand for both winter and summer for Auburn and Lidcombe zone substations.

2.1.1 Load forecast - Auburn

The Auburn zone substation has a total capacity of 75.9 MVA and a firm capacity of 41.0 MVA. In 2016/17, the maximum demand on the zone substation was 31.4 MVA at 1:45pm AEDT on 30 January 2017. The weather corrected demand at the 50 POE level was 28.7 MVA. The power factor at the time of summer maximum demand was 0.93.

Maximum demand has typically occurred in summer in past years. In the summer season, the maximum demand typically occurs between 12:15am and 2:00pm AEDT. The 50 POE forecast 7 year compound annual growth rate (CAGR) to 2023/24 for maximum demand is -0.1% for summer and -0.7% for winter.

Figure 1 – Demand forecast at Auburn zone substation

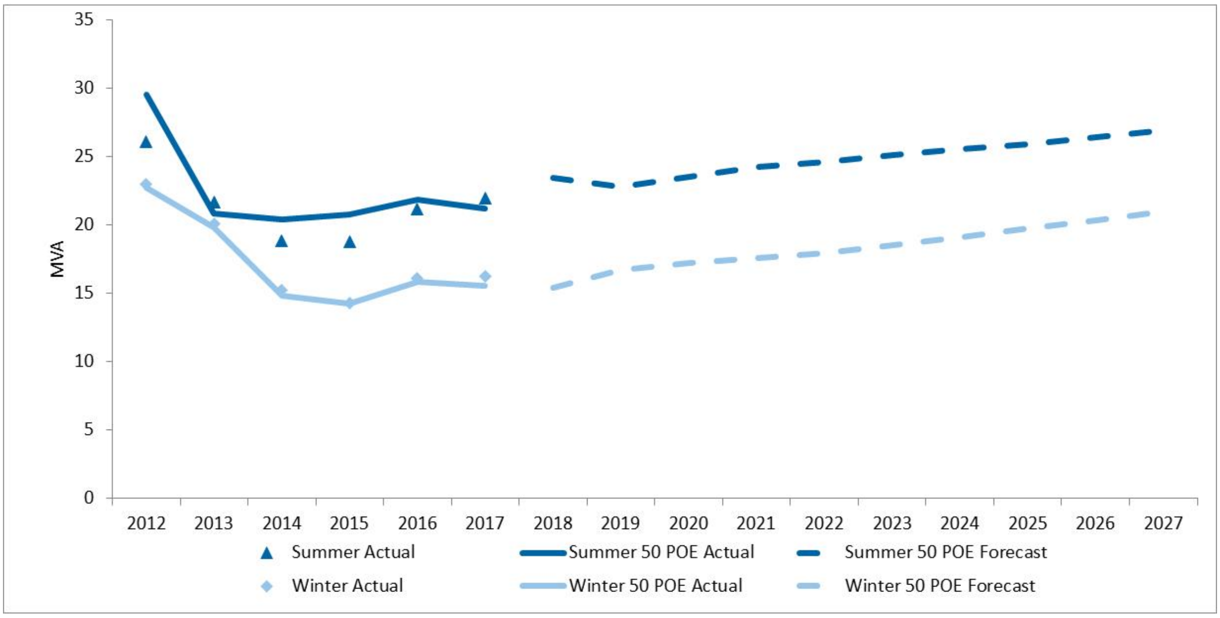


2.1.2 Load forecast - Lidcombe

The Lidcombe zone substation has a total capacity of 54.9 MVA and a firm capacity of 33.4 MVA. In 2016/17, the maximum demand on the zone substation was 22.0 MVA at 4:30pm AEDT on 10 February 2017. The weather corrected demand at the 50 POE level was 21.2 MVA. The power factor at the time of summer peak demand was 0.90.

Maximum demand has typically occurred in summer in past years. In the summer season, the maximum demand typically occurs between 3:00pm and 5:00pm AEDT. The 50 POE forecast 7 year compound annual growth rate (CAGR) to 2023/24 for maximum demand is +2.7% for summer and +3.0% for winter.

Figure 2 – Demand forecast at Lidcombe zone substation



2.2 Pattern of use

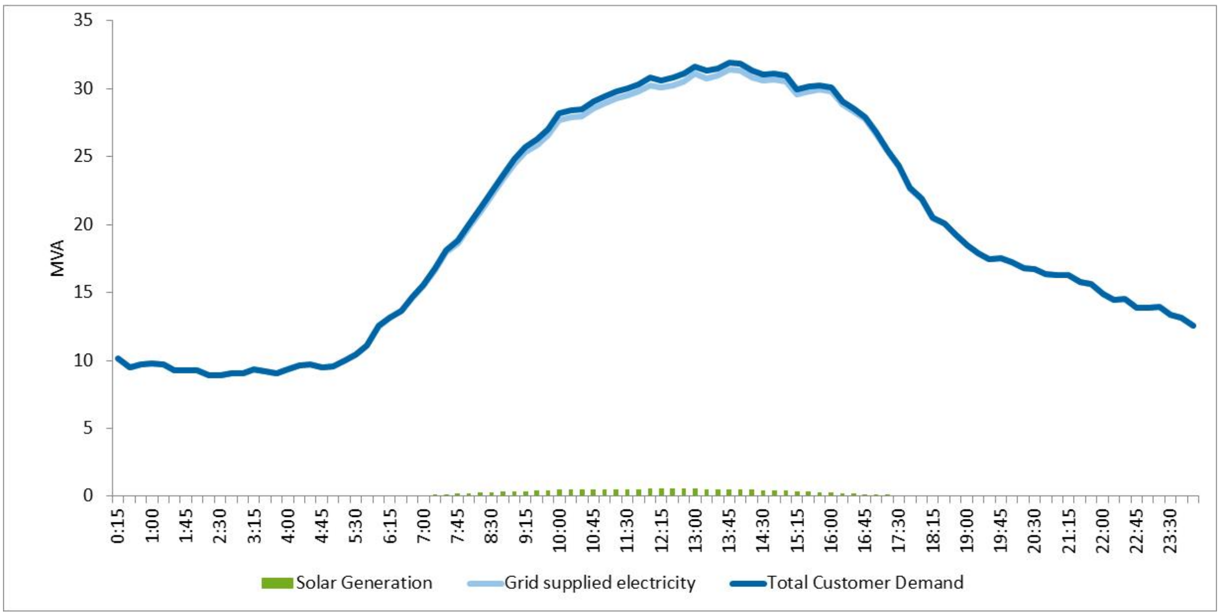
Summer peak electricity demand at Auburn and Lidcombe zone substations occur on hotter days driven predominantly by commercial loads.

2.2.1 Pattern of use - Auburn

Over the past 7 years, and where peak annual demand occurs in summer, the time of peak has typically occurred between 12:15pm and 2:00pm AEDT. As noted above, the most recent summer maximum demand occurred at 1:45pm AEDT.

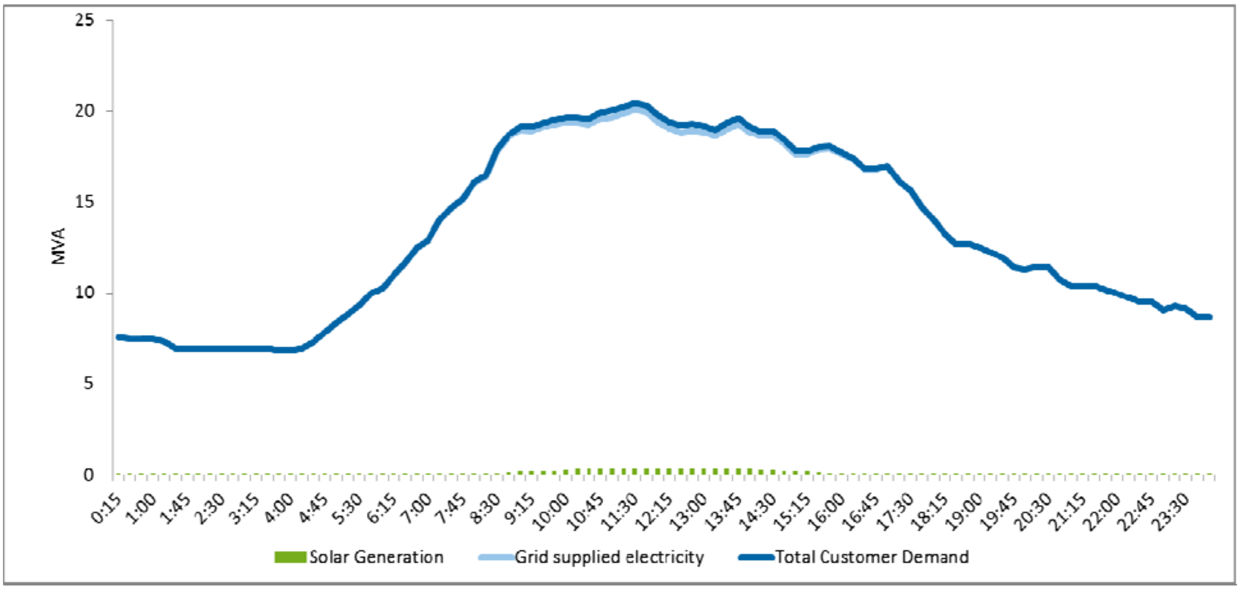
There is a total capacity of about 0.84 MW of solar PV connected to the zone substation. At the peak time on 30 January 2017, these PV systems supplied about 0.52 MW of the customer load. Figure 3 below shows the load trace for the 30 January 2017 maximum demand day including the contribution from customer installed solar power systems.

Figure 3 – Summer maximum demand profile at Auburn zone substation (30 January 2017)



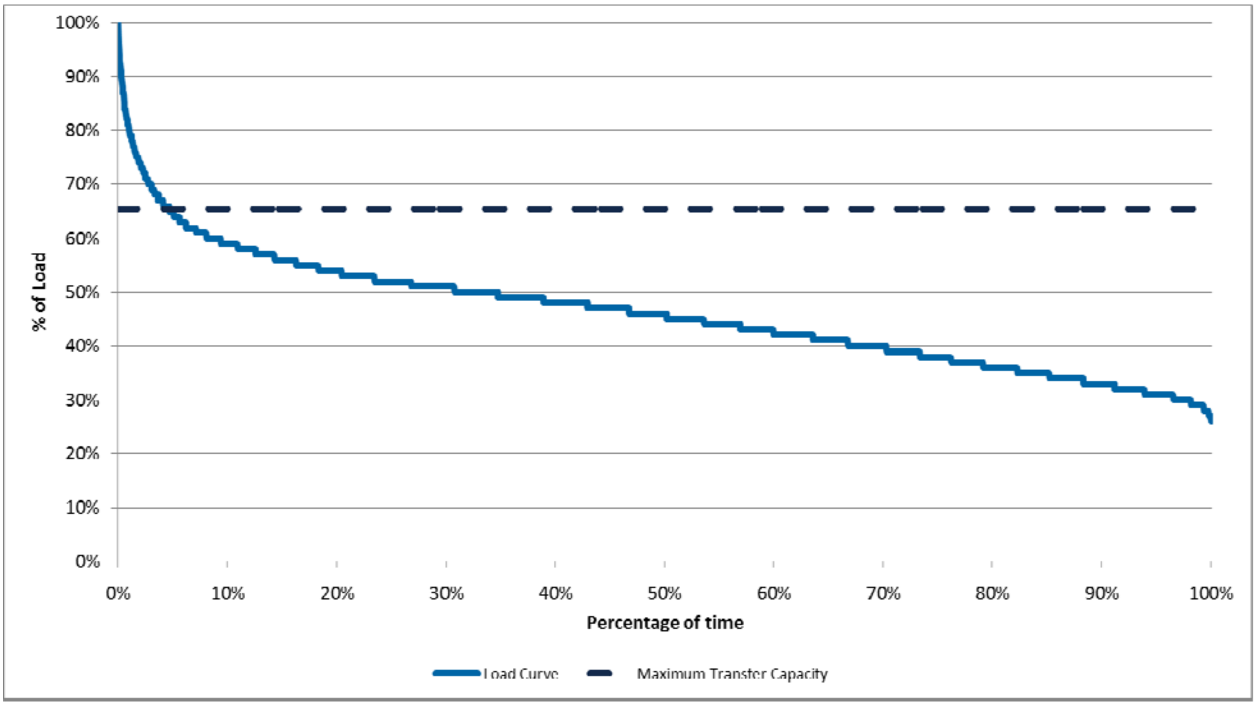
Winter peak electricity demand at Auburn zone substation typically occurs in the morning. Over the past 7 years, the time of winter peak has typically occurred between 9:45 am and 11:30pm AEST. Figure 4 below shows the load trace for the 27 June 2016 peak demand day including the contribution from customer installed solar power systems.

Figure 4 – Winter maximum demand profile at Auburn zone substation (27 June 2016)



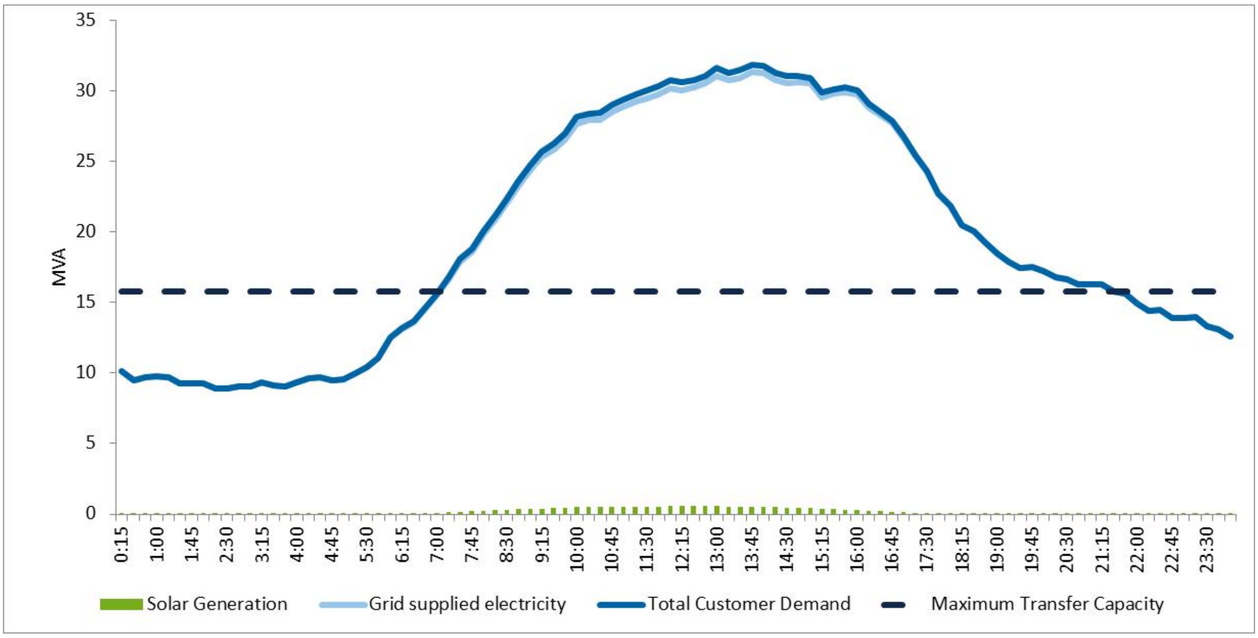
The Auburn zone substation has a current load transfer capacity of 15.8 MVA or about 50.4% of the most recent actual maximum summer demand and 78.7% of most recent actual maximum winter demand. Based upon the data period from May 2016 to April 2017, electricity demand for Auburn Zone Substation exceeds the transfer capacity for about 166 days and 1040 hours per year (12% of total hours) with 690 hours in summer and 350 hours in winter. Over this period, there is a total of about 2,820 MWh of unmet load in the case of a loss of network supply from Auburn zone substation. The load duration curve for the period from May 2016 to April 2017, noting the transfer capacity, is shown below in Figure 5.

Figure 5 – Auburn Zone Substation Load Duration Curve (May 2016 to April 2017)



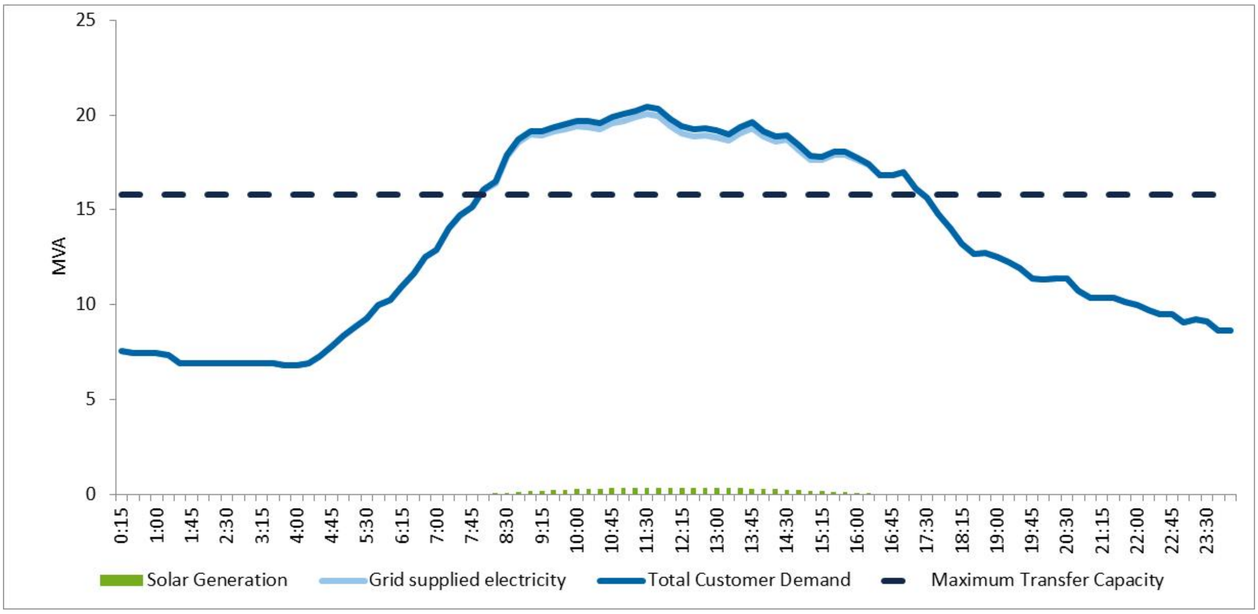
In the event of a network outage, and on a maximum summer peak demand day, after use of the maximum transfer capacity in an emergency switching of the network, there is a shortfall of network supply from 7:15am to 9:15pm or 14 hours. The maximum shortfall in network supply on 30 January 2017 would have been 15.6 MW at peak. See Figure 6 below.

Figure 6 – Summer maximum demand profile at Auburn zone substation with maximum load transfer



Similarly for a winter peak demand day, the shortfall in network supply would be for a total of 9 hours in the period from about 8:00am to 5:15pm. The maximum shortfall in network supply on 27 June 2016 would have been 4.3 MW at time of peak demand. See Figure 7 below.

Figure 7 – Winter maximum demand profile at Auburn zone substation with maximum load transfer

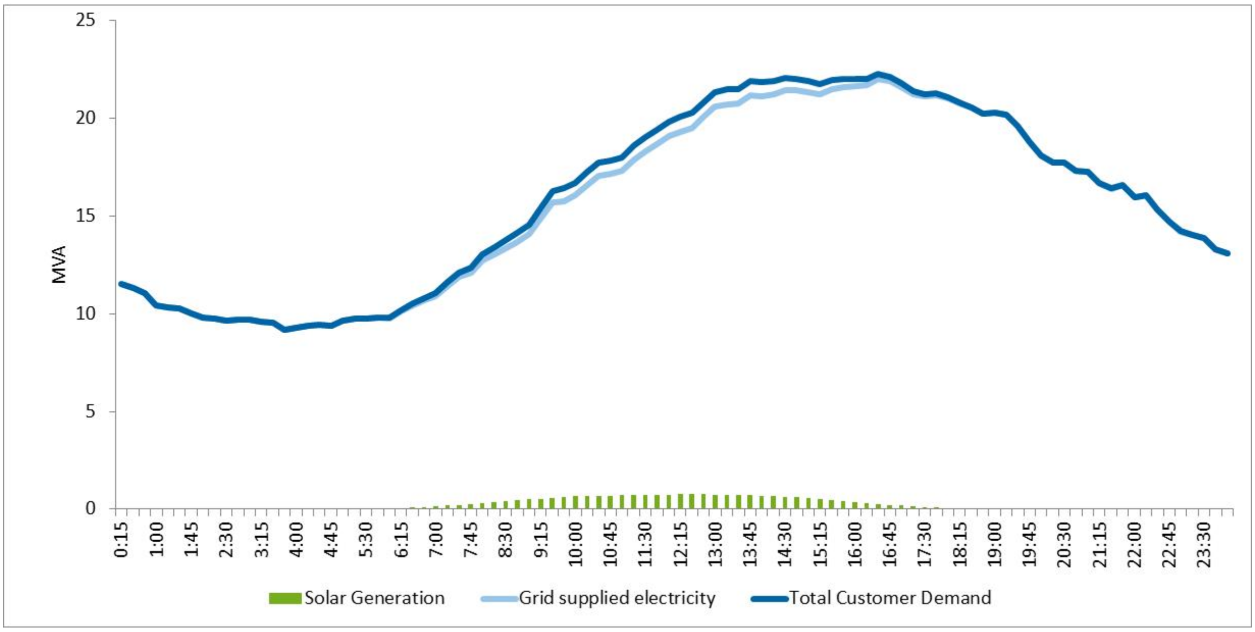


2.2.2 Pattern of use - Lidcombe

Over the past 7 years, and where peak annual demand occurs in summer, the time of peak has typically occurred between 3:00pm and 5:00pm AEDT. As noted above, the most recent summer maximum demand occurred at 4:30pm AEDT.

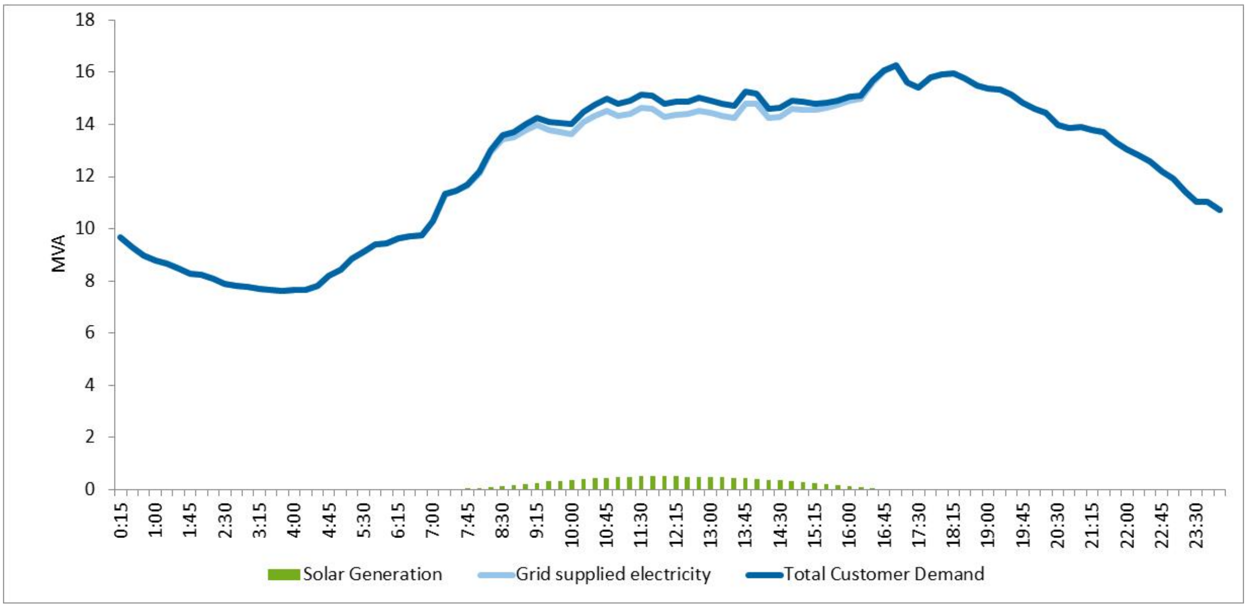
There is a total capacity of about 1.15 MW of solar PV connected to the zone substation. At the time of 4:30pm on 10 February 2017, these PV systems supplied about 0.28 MW of the customer load. Figure 8 below shows the load trace for the 10 February 2017 peak demand day including the contribution from customer installed solar power systems.

Figure 8 – Summer maximum demand profile at Lidcombe zone substation (10 February 2017)



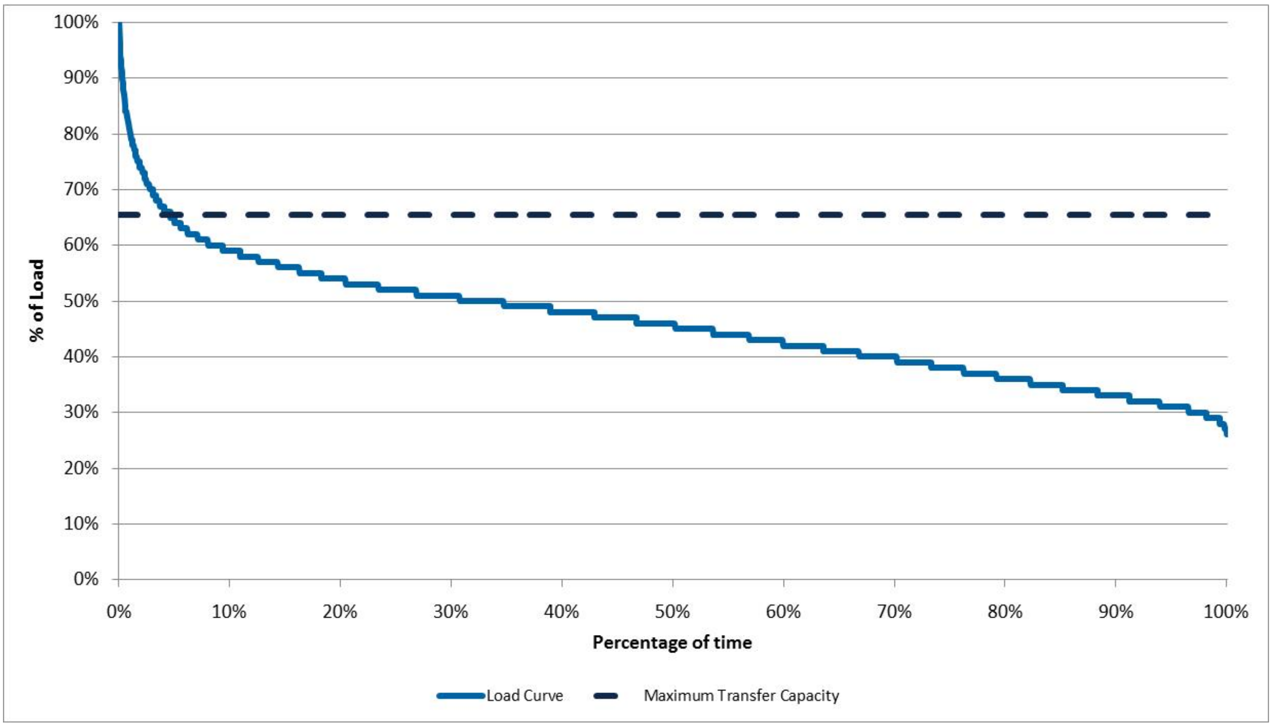
Winter peak electricity demand at Lidcombe zone substation typically occurs on a weekday. Over the past 7 years, the time of winter peak has typically occurred between 5:00pm and 6:00pm AEDT. Figure 9 below shows the load trace for the 27 June 2016 maximum demand day including the contribution from customer installed solar power systems.

Figure 9 – Winter maximum demand profile at Lidcombe zone substation (27 Jun 2016)



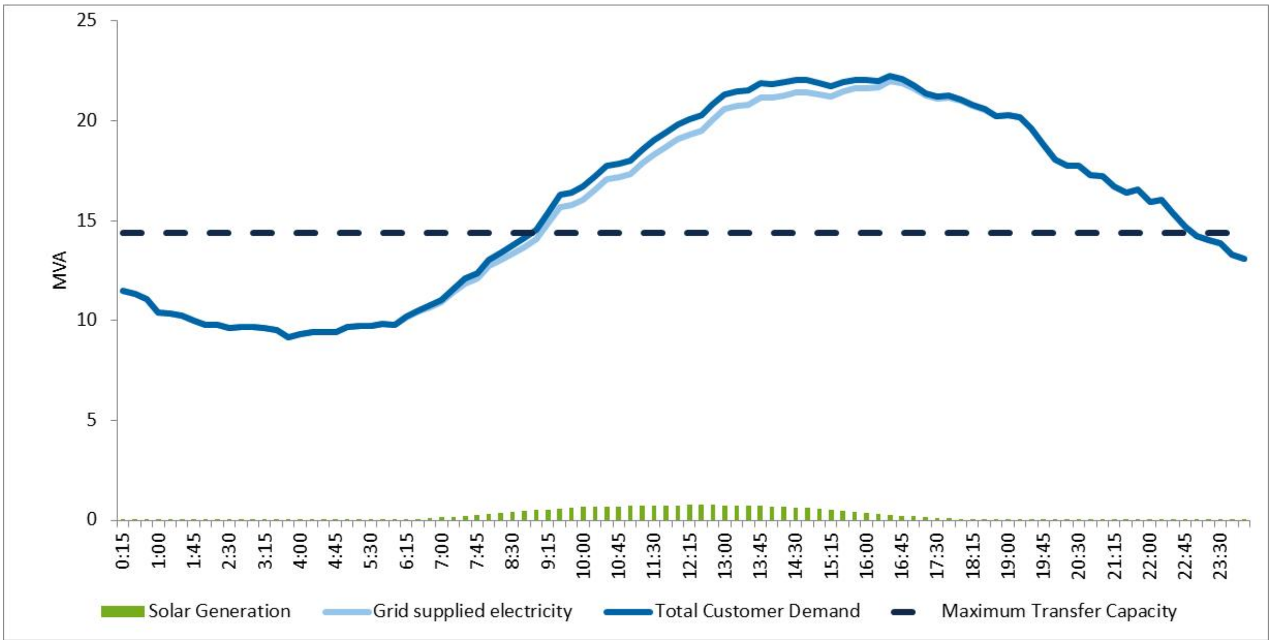
The Lidcombe zone substation has a current load transfer capacity of 14.4 MVA or about 65.5% of the most recent actual maximum summer demand and 88.6% of most recent maximum winter demand. Based upon the data period from May 2016 to April 2017, electricity demand for Lidcombe Zone Substation exceeds the transfer capacity for about 56 days and 350 hours per year (4% of total hours) with 335 hours in summer and 15 hours in winter. Over this period, there is a total of about 750 MWh of unmet load in the case of a loss of network supply from Lidcombe zone substation. The load duration curve for the period from May 2016 to April 2017, noting the transfer capacity, is shown below in Figure 10.

Figure 10 – Lidcombe Zone Substation Load Duration Curve (May 2016 to April 2017)



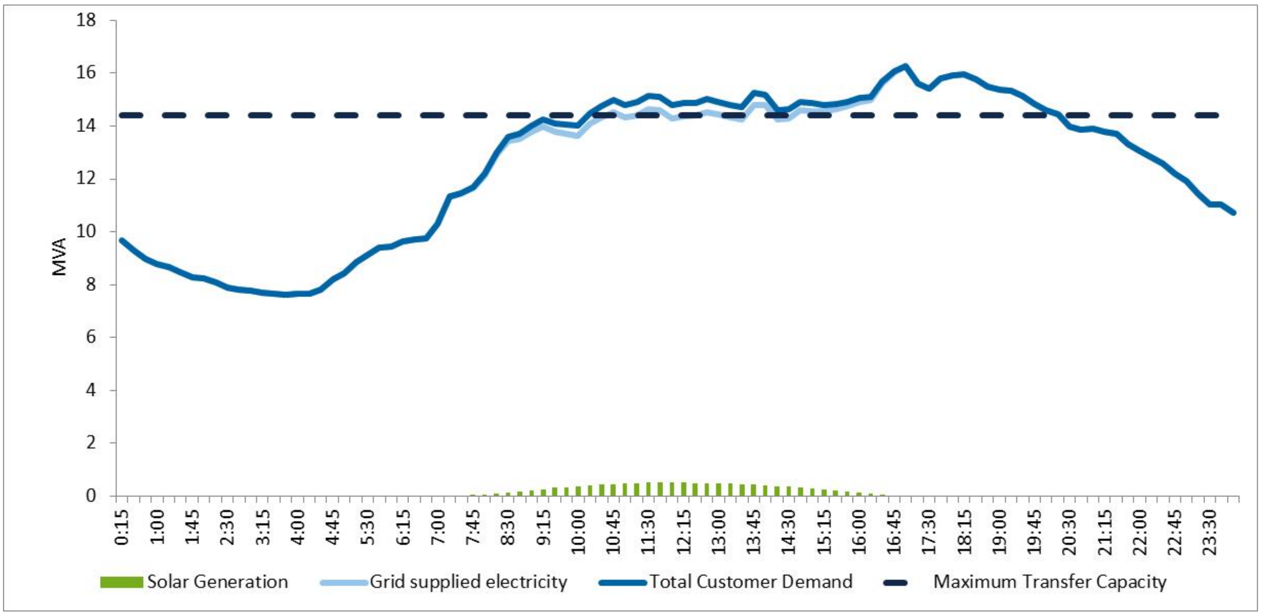
In the event of a network outage, and on a maximum summer peak demand day, after use of the maximum transfer capacity in an emergency switching of the network, there is a shortfall of network supply from 9:00am to 10:45pm or 14 hours. The maximum shortfall in network supply on 10 February 2017 would have been 7.6 MW at peak. See Figure 11 below.

Figure 11 – Summer maximum demand at Lidcombe zone substation with maximum load transfer



Similarly for a winter peak demand day, the shortfall in network supply would be for a total of about 6 hours in the period from about 2:30pm to 8:15pm. The maximum shortfall in network supply on 27 June 2016 would have been 1.8 MW at time of maximum demand. See Figure 12 below.

Figure 12 – Winter maximum demand at Lidcombe zone substation with maximum load transfer



2.3 Customer characteristics

Auburn and Lidcombe Zone Substations serve a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2016/17 period is as follows:

Table 1 – Customer characteristics - Auburn

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	2,610	673	90	3,373
% of Customers	77%	20%	3%	
Number of Solar Customers	133	23		156
% of Customers	5.1%	3%		
Annual Consumption (MWh)	12,370	19,905	64,616	96,890
% of Annual Consumption	12.8%	20.5%	66.7%	
Average Annual Consumption (MWh per customer)	4.7	30	718	

About 38% of residential customers live in detached homes with an average usage of about 5.8 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 4.1 MWh per year.

Table 2 – Customer characteristics - Lidcombe

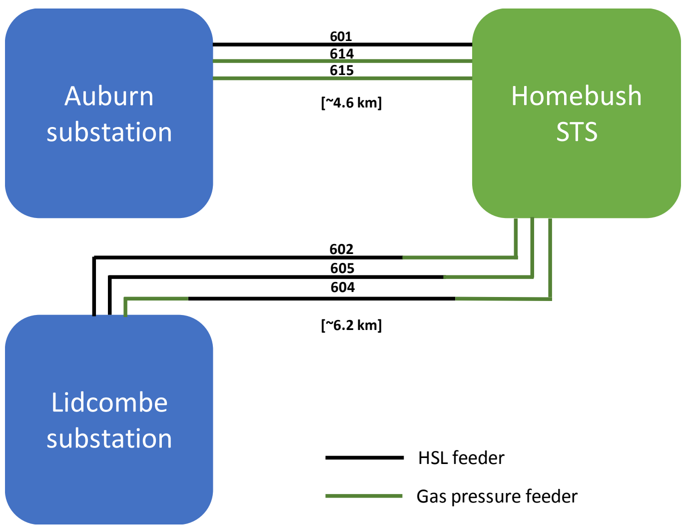
<table>
<tr><th>Item</th><th>Residential</th><th>Small Non-Residential</th><th>Large Non-Residential</th><th>Total</th></tr>
<tr><td>Number of Customers</td><td>6,137</td><td>792</td><td>63</td><td>6,992</td></tr>
<tr><td>% of Customers</td><td>88%</td><td>11%</td><td>1%</td><td></td></tr>
<tr><td>Number of Solar Customers</td><td>370</td><td colspan="2">17</td><td>387</td></tr>
<tr><td>% of Customers</td><td>6%</td><td colspan="2">2%</td><td></td></tr>
<tr><td>Annual Consumption (MWh)</td><td>29,581</td><td>19,723</td><td>35,250</td><td>84,553</td></tr>
<tr><td>% of Annual Consumption</td><td>35.0%</td><td>23.3%</td><td>41.7%</td><td></td></tr>
<tr><td>Average Annual Consumption (MWh)</td><td>4.8</td><td>25</td><td>560</td><td></td></tr>
</table>

About 50% of residential customers live in detached homes with an average usage of about 6.0 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.6 MWh per year.

2.4 System limitations and restoration timeframes

The Auburn and Lidcombe substations are both currently supplied by 33kV feeders (feeders 601, 614 and 615 to Auburn and feeders 602, 604 and 605 to Lidcombe) that originate from the Homebush sub-transmission station (STS) that were mostly commissioned in the late 1940s and 1950s. These feeders consist of both gas pressure and HSL sections, as illustrated in the stylised network diagram below.

Figure 13 – Current supply arrangements for the Auburn and Lidcombe zone substations[1]



These feeders are reaching or have exceeded their useful lives. The oldest feeder sections were commissioned in 1942 and are now 31 years past their expected useful life, while most sections are approximately 24 to 20 years past their expected useful life. Gas pressure sections on feeders 605 and 614 are among the worst 40 feeders for gas leakages and worst 20 feeders for unavailability among the wider Ausgrid gas feeder fleet.

[1] Please note that this figure is designed to be illustrative of the types, and distances, of each feeder technology. To do so, it illustrates the distances of each feeder type, relative to one-another. It is not intended to be an accurate depiction of the *location* of each feeder type.

Current supply arrangements for the Auburn and Lidcombe zone substations have a degree of redundancy. As noted above, three feeders supply each substation and therefore load could be transferred to the two remaining feeders should one of the three feeders experience a fault or be out of service. However, outages of two out of three feeders supplying each substation would likely lead to some degree of involuntary load shedding. As feeders age, the likelihood of multiple feeder failures increases which in turn is likely to lead to involuntary load shedding.

In the event of multiple failures, there is limited capacity to move load away from Auburn and Lidcombe substations given network constraints in the Inner West network area. Consequently, restoration of supply to customers in the Auburn and Lidcombe area would depend on the time needed to return feeders to service. Based on historical experience, this may take between 10 and 25 days.

Both the degree of redundancy and the ability to transfer load elsewhere have been taken into account by Ausgrid in forecasting expected unserved energy.

3 Proposed preferred network option

The preferred option is to install new feeders from Endeavour Energy's Camellia substation to both Auburn and Lidcombe substations, whilst utilising existing HSL feeder sections. The three options that have been assessed to address future reliability concerns are summarised in the table below.[2]

Table 3 – Summary of the credible options considered

Network option description	Approximate combined length of new feeders	Estimated capital cost
Option 1 –New feeders from Homebush (i.e., 'like-for-like' route)	40km	$36 million
Option 2 – New feeders from Endeavour Energy's Camellia substation to both Auburn and Lidcombe	20km	$26 million
Option 3 – New feeders from Endeavour Energy's Camellia substation to both Auburn and Lidcombe, whilst utilising existing HSL sections	15km	$20 million

Option 3 is the preferred option at this draft stage

Option 3 has been found to be the preferred option, which satisfies the RIT-D. It involves the installation of 33 kV feeders from Camellia STS to Auburn and Lidcombe zone substations utilising the existing HSL feeder sections that run from Homebush STS to Lidcombe zone substation. Ausgrid is the proponent for Option 3.

Option 3 provides the following benefits:

- it involves the lowest cost out of all three credible options considered (and involves less than half the combined length of new feeders of a 'like-for-like' replacement under Option 1);
- it complements existing 11kV switchgear works underway at the Lidcombe zone substation;
- it utilises spare capacity at Endeavour Energy's Camellia STS and avoids unnecessary duplication of network capacity;
- it defers upstream investments that would otherwise be required if supply of Auburn and Lidcombe were to continue to come from Homebush STS; and
- it addresses asset condition issues on feeders supplying Auburn and Lidcombe zone substations and therefore is expected to reduce involuntary load shedding and operating expenditure related to unplanned corrective maintenance.

The scope of Option 3 includes:

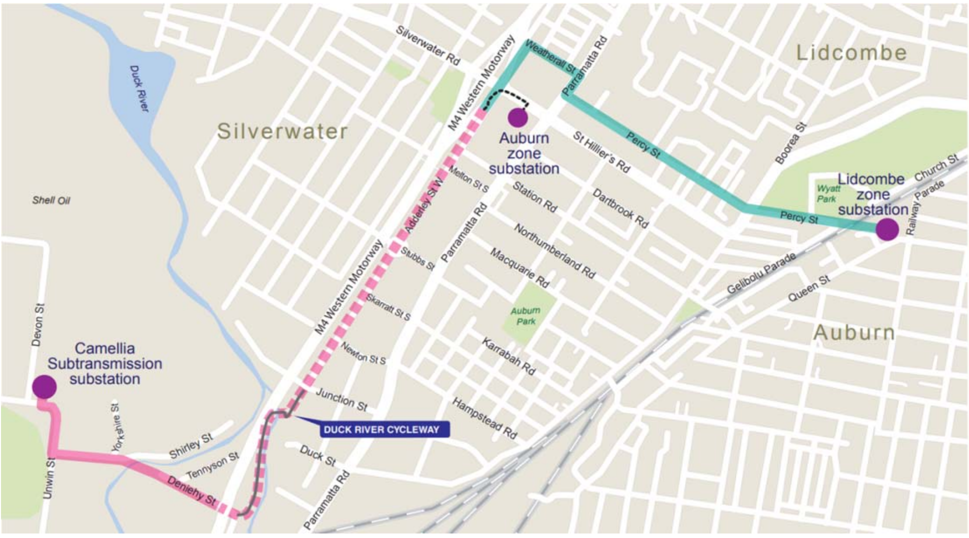
- installation of four feeders, approximately 3.5km long, from Camellia STS to Adderley Street near Auburn zone substation;
- installation of one overhead feeder, approximately 2.1km long, from Auburn to Lidcombe zone substation;
- connection of existing HSL cable sections to existing transformers at the Lidcombe zone substation;
- installation of three-way ring main isolators at Auburn zone substation as one 33 kV feeder would share one of the transformers at Auburn zone substation and one of the transformers at Lidcombe zone substation;
- uprate of existing Transformer 5 at Auburn zone substation to include an emergency rating of 31 MVA; and

[2] Ausgrid also considered decommissioning one of the zone substations and uprating the other (including to 132 kV). However, the cost and technicalities of these options are considered to render them not feasible, when compared to the three options outlined above

- retirement of the existing underground gas pressure cable sections of the 33 kV feeders supplying Auburn and Lidcombe zone substations.

Figure 14 below depicts the new feeders proposed under Option 3. Specifically, they will originate from Camellia STS, crossing the M4 motorway underground and following the motorway east to connect to Auburn zone substation and then south to Lidcombe zone substation.

Figure 14 – Detailed route of proposed preferred option



The proposed route from Camellia STS to Auburn zone substation is mainly through industrial areas, crossing Duck Creak and the existing M4 Western Motorway by following the Duck River Cycleway. Ausgrid plans to use underground cables in certain areas in response to community feedback and to minimise risks along the M4 Western Motorway.

The proposed overhead route between Auburn zone substation and the Lidcombe zone substation will pass primarily through industrial areas in Lidcombe and cross under the main western rail line at Percy Street. Ausgrid is proposing to locate the cables on the western side of Percy Street and incorporate them on existing low voltage powerline structures, which will minimise the impact of construction. Underground cables are proposed to be installed from Adderley Street West to the Auburn zone substation at 2 Silverwater Road. Trenching will need to be laid between the eastern end of Adderley Street West and along Silverwater Road to the substation.

The estimated cost of this option is $21 million and is assumed to take four years to complete construction. Ausgrid assumes that construction begins in 2017/18 with construction scheduled for completion in 2020/21 (commissioning in June 2021) and decommissioning of gas feeders in the following year. Once commissioned, operating costs are estimated to be approximately $98,000 per annum (around 0.5 per cent of capital expenditure).

Overall, this finding confirms the earlier joint planning assessment exercises undertaken by Ausgrid and Endeavour in 2013.

4 Assessment of non-network solutions

4.1 Required demand management characteristics

A viable demand management solution must be capable of reducing the load on Auburn and Lidcombe zone substation sufficient to retain supply to customers over the 10-25 days required for restoration of supply in the event of an unplanned cable outage. This reduction in supply can be permanent or temporary but must offer support in both summer and winter, align with the load profiles post emergency load transfer and be cost effective in comparison with the preferred network alternative.

Due to the scale of the shortfall in electricity supply, we consider that a combination of permanent and temporary demand reductions would 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, emergency load transfer capacities and customer characteristics.

A detailed assessment of the load profile for Auburn and Lidcombe zone substations over the May 2016 to April 2017 period shows that the shortfall in supply after emergency load transfers have been implemented is significant. Refer to Table 4 and Table 5 below for details on the network support requirements for the years from 2019/20 to 2021/22.

Table 4 – Customer supply shortfall at Auburn substation

Year	MW	MWh	Days/year		Hours/year	
			Summer	Winter	Summer	Winter
2019/20	11.5	2,005	76	51	571	150
2020/21	11.7	2,117	77	54	588	176
2021/22	12.1	2,281	78	60	615	212

Table 5 – Customer supply shortfall at Lidcombe substation

Year	MW	MWh	Days/year		Hours/year	
			Summer	Winter	Summer	Winter
2019/20	9.1	1,618	68	34	568	159
2020/21	9.8	2,021	75	52	659	267
2021/22	10.2	2,294	78	61	718	336

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 identified need in 2019/20 and/or 2020/21 for reducing the load at risk and 2021/22 for deferral of the network investment.

4.2 Demand management value

Ausgrid has assessed potential demand management options to achieve the required demand reduction to make the project deferral technically and economically viable. An assessment of the costs and benefits has shown that the value of the deferred benefit is substantially greater than the financial benefit from deferring the capital expenditure. This results in available demand management funds of $0. This is principally due to the significant share of the risk (benefit) associated with the annual repair cost of the aged assets.

Ausgrid also assess the viability of using demand management support prior to project completion in 2020/21 to reduce the risk of a customer outage. Table 6 below indicates the available funds to reduce load at risk in 2019/20, expressed for a range of demand reductions. Note the stated available funds are indicative only and in addition to an allowance of $75,000 per year to cover any Ausgrid administrative costs

Table 6 – Funds available for demand management (combined Auburn and Lidcombe substations)

Average % EUE reduction per year	Average % Total risk reduction per year	Total available funds in 2019/2020 & 2020/2021	Peak Load Reduction required (MW)	Load Reduction required (MWh)	Available $ per MWh
36%	12%	$0.58m	3	3,345	$173
48%	16%	$0.82m	4	4,088	$201
100%	33%	$1.90m	9	6,420	$296

4.3 Demand management options considered

Ausgrid has considered a number of demand management technologies to determine their commercial and technical feasibility to assist with the identified need at the Auburn and Lidcombe zone substations. Each of the demand management technologies considered is summarised below.

4.3.1 Customer power factor correction

While this option is technically feasible and offers permanent reductions sufficient to cover the large number of unmet load hours, there are few customers on a kVA demand tariff supplied from Auburn and Lidcombe Zone Substations. Of the 10,365 customers connected to Auburn and Lidcombe Zone Substations, only 153 are on a kVA demand tariff. Analysis of customer interval data indicates a technical potential of only about 0.3 MVA. Commercial potential is likely to be about 0.1 MVA. At a likely cost of about $25-50 per kVA, this solution is likely to be cost effective, but is estimated to contribute less than 1% of the requirement.

4.3.2 Customer solar power systems

While this option is technically feasible and offers permanent reductions, solar power systems are not estimated to offer a material reduction in grid supplied demand during the period when there is a shortfall in grid supply.

Analysis of interval data for Auburn Zone Substations show that solar generation is greater than about 30% of maximum panel capacity for 62% of unmet load hours in winter, 89% of unmet load hours in summer and about 88% of overall unmet load hours. This is principally due to the early afternoon time of peak in summer and late morning time of peak in winter.

Analysis of interval data for Lidcombe Zone Substations show that solar generation is greater than about 30% of maximum panel capacity for 5% of unmet load hours in winter, 61% of unmet load hours in summer and about 61% of overall unmet load hours. This is principally due to the late afternoon time of peak in summer and early evening time of peak in winter.

At present there are 2.0 MW of solar connected to Auburn and Lidcombe zone substations. A 300% increase in installed solar power systems above the current projected trend (75% additional) is estimated to contribute only about 15% of the network support requirement. There is no indication that a material share of the unmet load could be reduced through an increase in the take-up of new solar power systems in the area.

4.3.3 Customer energy efficiency

While this option is technically feasible and offers permanent reductions, improvements to customer energy efficiency are not estimated to offer a sufficiently cost efficient alternative, nor potentially a sufficiently material reduction in grid supplied demand during the period when there is a shortfall in grid supply. Assuming modest incentives of 10-15% of customer investment cost could encourage customers to install a greater scale of energy efficiency improvements than would otherwise occur, we estimate an average cost of about $1000-2000 per MWh depending upon the level of additionality and coincidence with the demand shortfall. At about 4 to 8 times the available funds, this solution is not likely to offer a cost competitive alternative.

4.3.4 Demand response (curtailment of load)

Customer curtailment of load is a common and effective technique for deferring network investment where the need is for short time periods and few days but has not been shown to be viable for the extensive hours and consecutive days of network support required for the network issue at Auburn and Lidcombe zone substations.

Large customer demand response has historically been priced at $75-150 per kVA for 20-60 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). Considering the costs of acquisition and requirement for support in two seasons each year, we would estimate the average cost for demand response to be about $2000 to $3000 per MWh for large customer demand response and greater than $5000 per MWh for small customer demand response. At a cost many times the available funds, this solution is not likely to offer a cost competitive alternative.

4.3.5 Dispatchable generation

Dispatchable generation is another common and effective technique for deferring network investment where the need is for short time periods and few days but has not been shown to be viable for the extensive hours and consecutive days of network support required for the network issue at Auburn and Lidcombe zone substations.

Large customer dispatchable generation has historically been priced at $50-150 per kVA for 20-60 hours of dispatch per season. Considering the costs of acquisition and requirement for support in two seasons each year, we would estimate the average cost for this form of demand response to be well in excess of the available funds. Furthermore, as this solution commonly sources existing standby diesel generators; environmental compliance issues are likely to constrain the number of available operating hours.

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.