Addressing increased customer demand requirements in the Gillieston Heights area

REQUEST FOR PROPOSAL

30 APRIL 2019

Ausgrid

Contents

1 Background

Ausgrid serves 1.7 million customers across 22,000 square kilometres of ‘poles and wires’ that stretch from Sydney, through the Central Coast and up to the Hunter Valley. Based on latest demand forecasts, Ausgrid has identified emerging localised electricity network capacity constraints in the Gillieston Heights area. Gillieston Heights is part of the City of Maitland LGA in the Hunter Region of NSW.

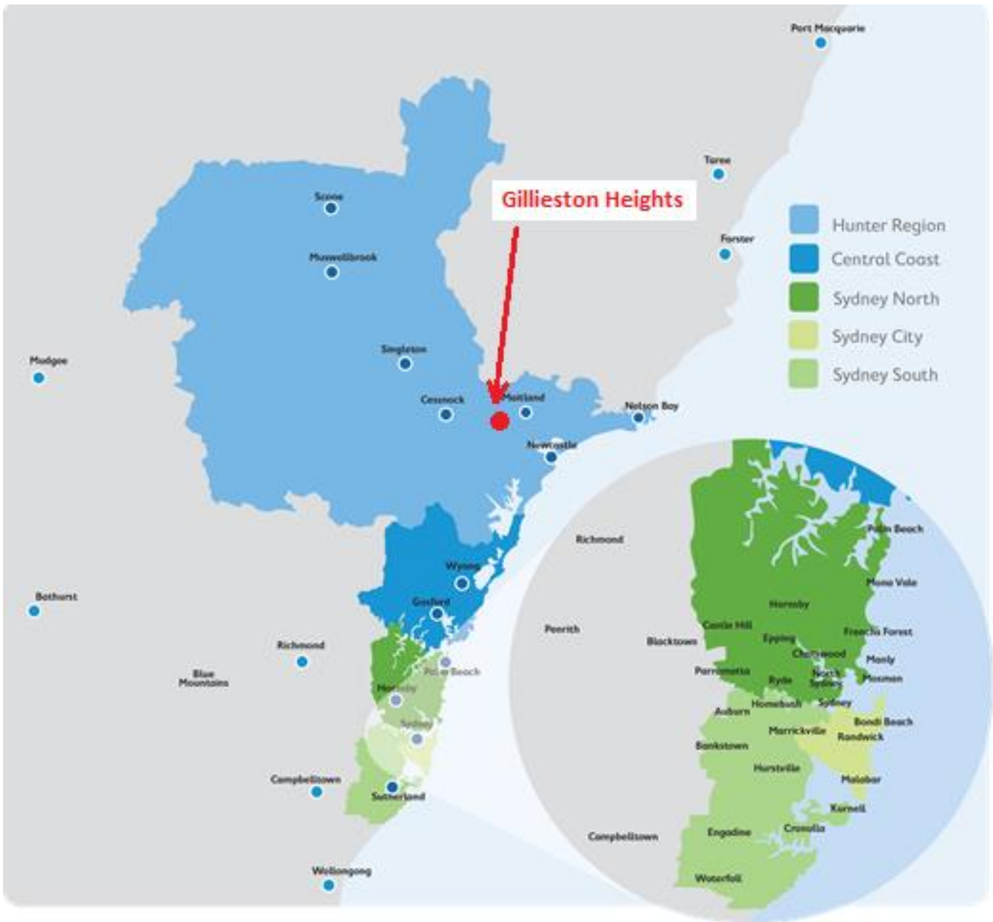
Over the last decade the region surrounding Gillieston Heights has changed from a non-urban to urban planning region due to significant residential growth. Growth in this area is expected to continue from development of available residential lots over the next six years. As part of the Distribution Network Planning standards, Ausgrid has identified that there is an emerging network constraint associated with three interconnected 11kV feeders (Metford 83307, Telarah 48010 and Kurri 80923).

Demand Management offers a potential alternative to avoid or delay the need for capital expenditure in the region’s distribution network. This RFP seeks submissions for the provision of non-network solutions to reduce peak demand and avoid or defer the proposed network investment.

In the event that there are no non-network proposals received by Ausgrid or the proposals assessed are not considered technically feasible or cost effective, Ausgrid will proceed with the most favourable supply-side network option in order to alleviate the network constraint.

The image below highlights Ausgrid’s network area and shows the approximate location of Gillieston Heights.

Image 1 – Ausgrid’s electricity distribution network map



1.1 Purpose of this document

This Request for Proposal (RFP) document is an invitation to demand management proponents to submit non-network solutions to be considered by Ausgrid to satisfy its objective. This RFP provides:

- Background information on the network capacity limitations;
- The demand reduction required by load quantum and time;
- The amount of funds available for demand reductions based on deferral of the proposed supply-side network investment;
- An information pack to assist proponents in developing their proposals;
- Instructions on how to make a submission via Tenderlink; and
- An invitation for interested parties to submit credible non-network options for reducing peak demand on the network.

Ausgrid welcomes questions from proponents in order clarify any questions and finalise their submission. For all questions about the Gillieston Heights RFP, please direct them via the Tenderlink portal. For any general questions about Ausgrid's demand management process, contact us at demandmanagement@ausgrid.com.au.

1.2 Ausgrid's objective

Ausgrid's objective is to obtain sufficient customer demand reductions in the affected network area to address the forecast capacity constraints. A successful non-network option is one that is technically feasible and offers a lower cost alternative (net present value) to the preferred supply-side network option.

2 Description of Network Need

2.1 Description of Capacity Constraint

Electricity demand is forecast to increase in the Gillieston Heights area. The forecast growth is attributed to a number of residential developments which are driving capacity constraints on three (3) of the 11kV distribution feeders in the area.

2.2 Required Demand Reductions

The following table shows the forecast capacity constraints for each of the three feeders based upon Ausgrid's planning criteria.

Table 1 – Annual Forecast Capacity Constraints for affected feeders (kVA)

Forecast Capacity Constraints (kVA)	Year 2019/20	Year 2020/21	Year 2021/22	Year 2022/23	Year 2023/24
Metford zone substation feeder 83307		419	965	1511	2057
Telarah zone substation feeder 48010		381	914	1448	1981
Kurri zone substation feeder 80923	190	786	1381	1976	2571

Due to the interconnectivity of the local electricity network, outages on one feeder can be supported by the surrounding feeders. Consequently, the forecast capacity constraint is not the sum total of the forecast capacity constraint for all feeders. And because the network interconnectivity is finite, the demand reduction required is greater than the maximum forecast capacity constraint for any one feeder.

Note that due to the local network interconnectivity, demand reductions from an additional feeder (Kurri 80914) can also support the demand reductions required.

A summary of the demand reductions required to defer network augmentation is presented in table 2 below. As the required demand reduction is a function of the location of the actual customer demand reductions, the required demand reductions are presented as a range. These figures are to be used in this RFP as the required demand reductions.

Table 2 – Demand reductions required

Number of years deferred	Demand reduction required (kVA)
1	190
2	790 - 1000
3	1400 - 1700

2.2.1 **2019/2020 requirement**

The Kurri zone substation feeder 80923 is the only feeder with a forecast capacity constraint in 2019/20. To support a one year deferral, a 190kVA reduction in maximum demand is required from the customers located in the area identified as the *Group A region* highlighted in image 2 and 3 below. A Google Maps kmz file detailing the boundaries are provided in the data pack available through the Tenderlink portal.

Image 2 – Group A region map - 2019/20 network need

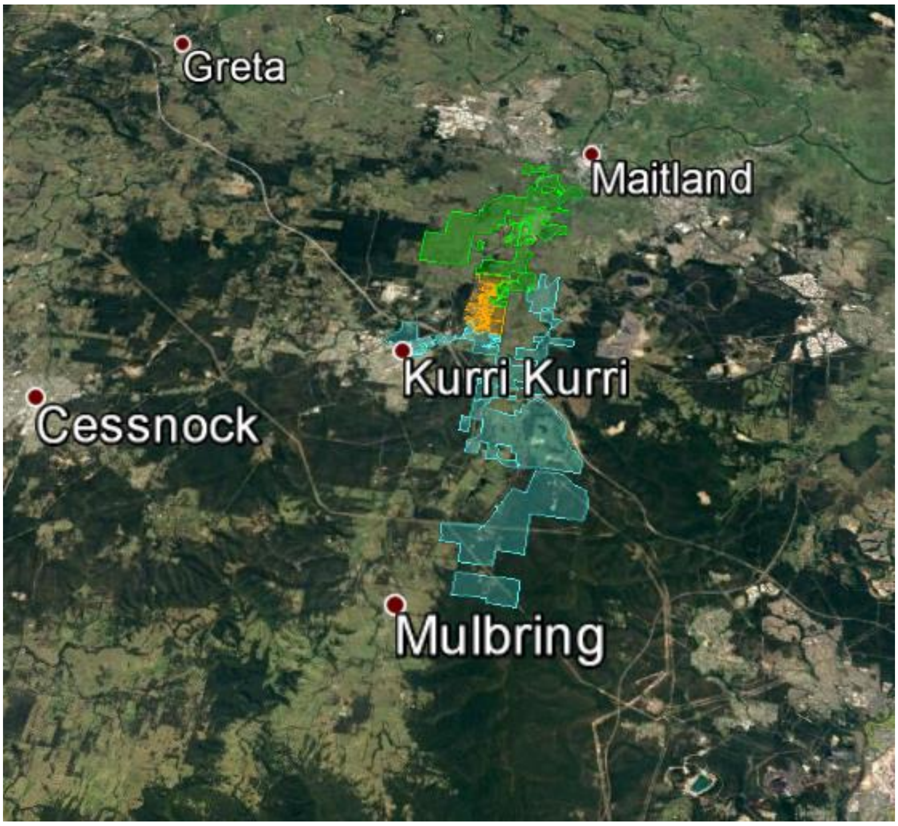
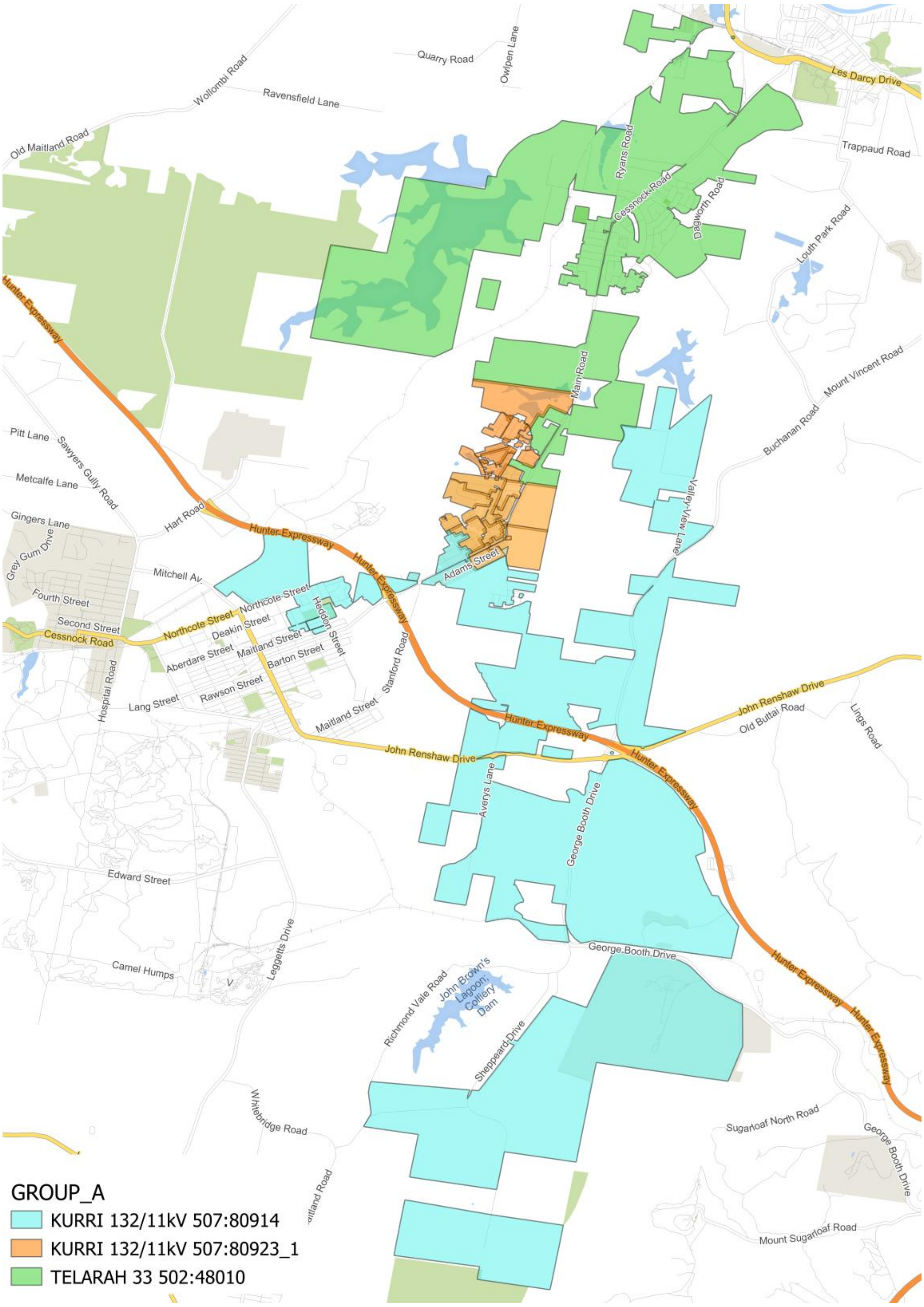


Image 3 – Group A region map - 2019/20 network need



The customers in the Group A region are described in Table 3 below.

Table 3 – Group A region – customer characteristics

	Residential	Non-residential
Number of customers	2,840	84
Annual total consumption (MWh)	18,859	7,133
Annual consumption (MWh/customer)	7	85
Number of customers with solar power	613	
Percentage of customers with solar power	21%	
Total solar power capacity (kW)	2,596	
Average solar capacity (kW/customer)	4.2	
Number of customers with battery systems	15	0
Number of customers with smart meters	347	16
Percentage of customers with smart meters	9%	30%

2.2.2 Required demand reductions in 2020/21 and 2021/22

In 2020/21 and beyond, there is a forecast capacity constraint on each of the three feeders. Due to interconnections of feeders, demand management can be implemented on a broader group of customers to achieve the required load reduction. In 2020/21, we estimate that a customer demand reduction of about 790-1000kVA across all relevant feeders (customers identified as group B) can delay network upgrades for another year. For 2021/22, we estimate that a customer demand reduction of about 1400-1700kVA across all relevant feeders (customers identified as group B) can delay network upgrades for a further year. Customers in group B are located on feeders 48010, 80923 and 80914 and a restricted group of customer supplied from feeder 83307. Customers in group B consist of those customers in group A, plus an additional set of customers.

The Group B region is shown in image 4 and 5 following. A Google Maps kmz file detailing the boundaries are provided in the data pack available through the Tenderlink portal.

Image 4 – Group B region map – 2020/21 and 2021/22 network need

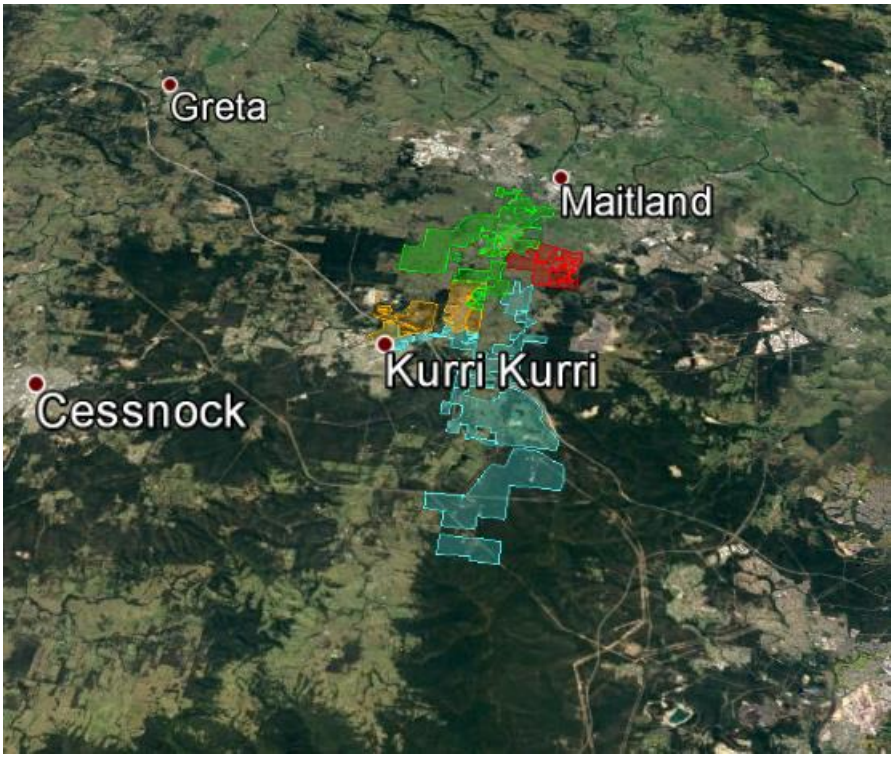
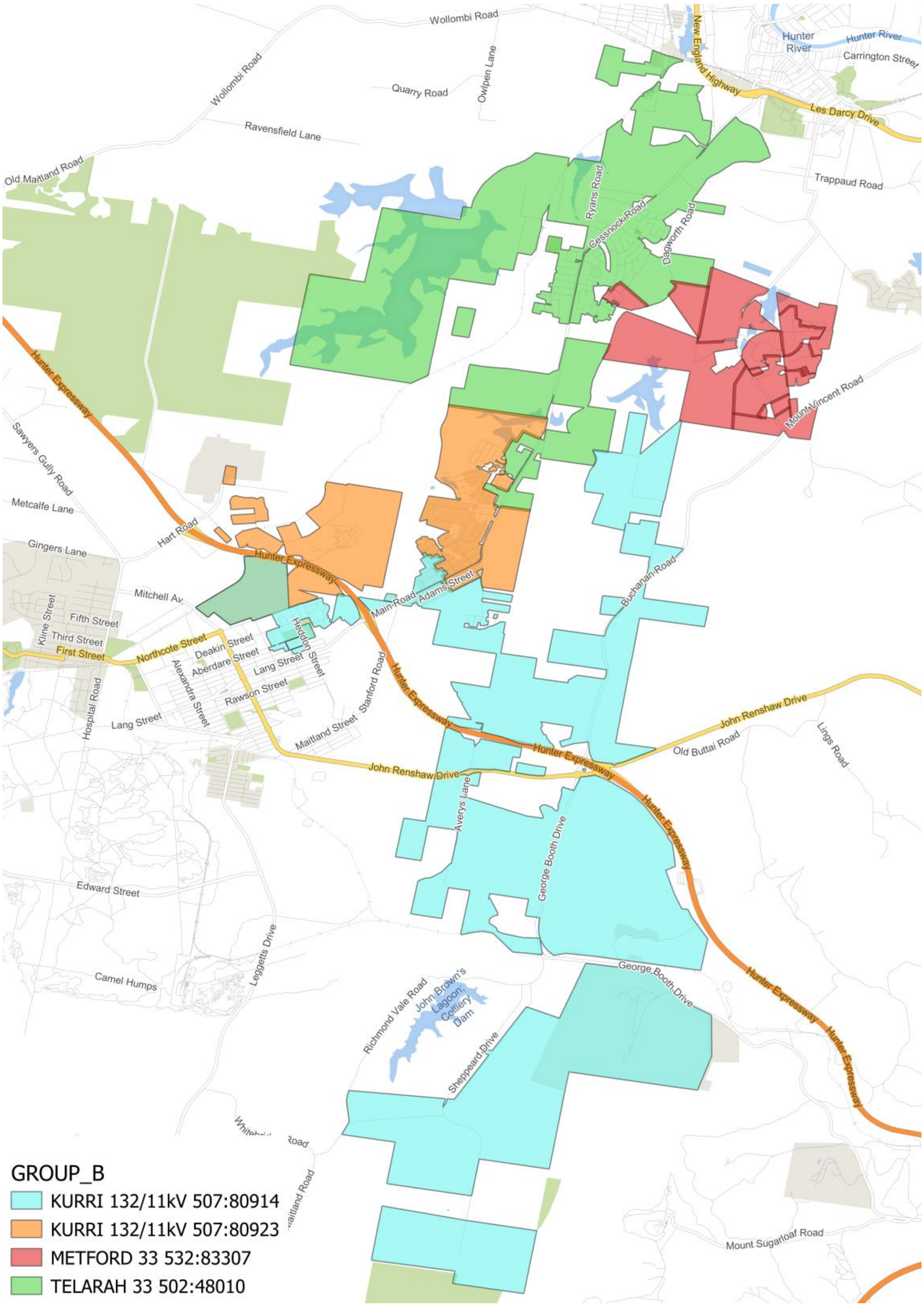


Image 5 – Group B region map – 2020/21 and 2021/22 network need



The customers in the Group B region are described in Table 4 below.

Table 4 – Group B region – customer characteristics

	Residential	Non-residential
Number of customers	3,054	94
Annual total consumption (MWh)	21,315	10,557
Annual consumption (MWh/customer)	7	112
Number of customers with solar power	672	
Percentage of customers with solar power	21%	
Total solar power capacity (kW)	2,946	
Average solar capacity (kW/customer)	4.4	
Number of customers with battery systems	16	0
Number of customers with smart meters	311	19
Percentage of customers with smart meters	10%	27%

2.3 Customer Demand Characteristics

To illustrate the annual and daily trends for customer demand in the Gillieston Heights, load data for the relevant feeders are presented below. The relevant load data is also included in the data pack available through the Tenderlink portal.

Figure 1 below shows the combined demand on the four feeders, to give an indication of the seasonal timing of peak demands. It is clear that peak demand, and therefore the requirement to defer the maximum, occurs on [hot] summer days.

Figure 1 – 2018/19 annual demand – all 11kV feeders combined

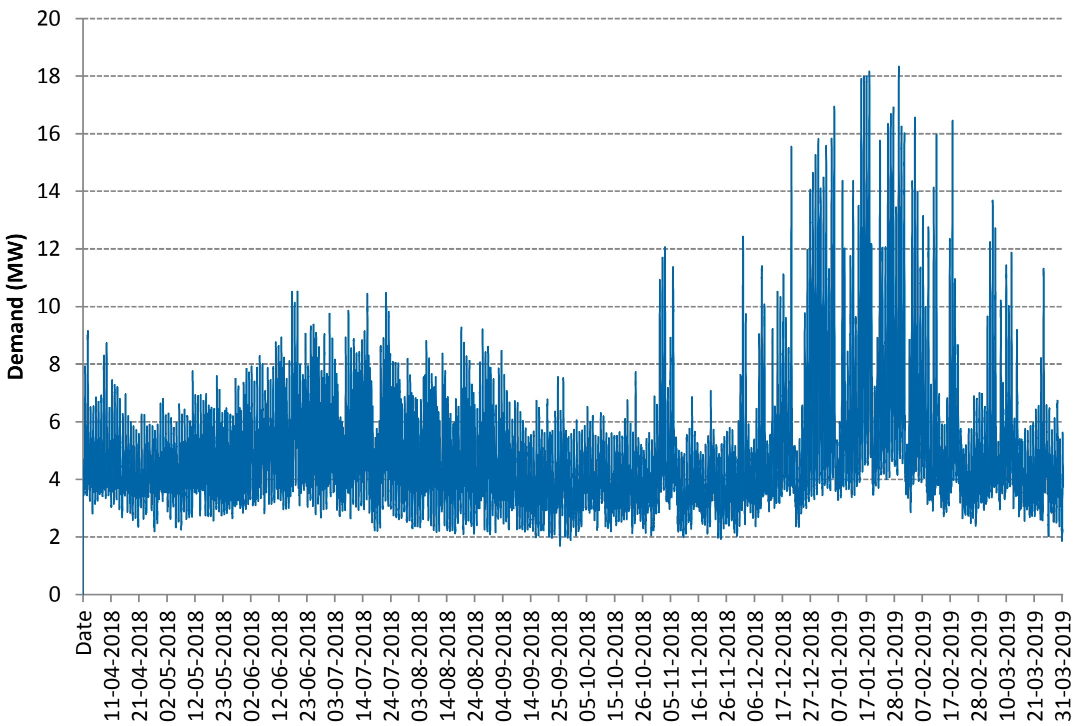
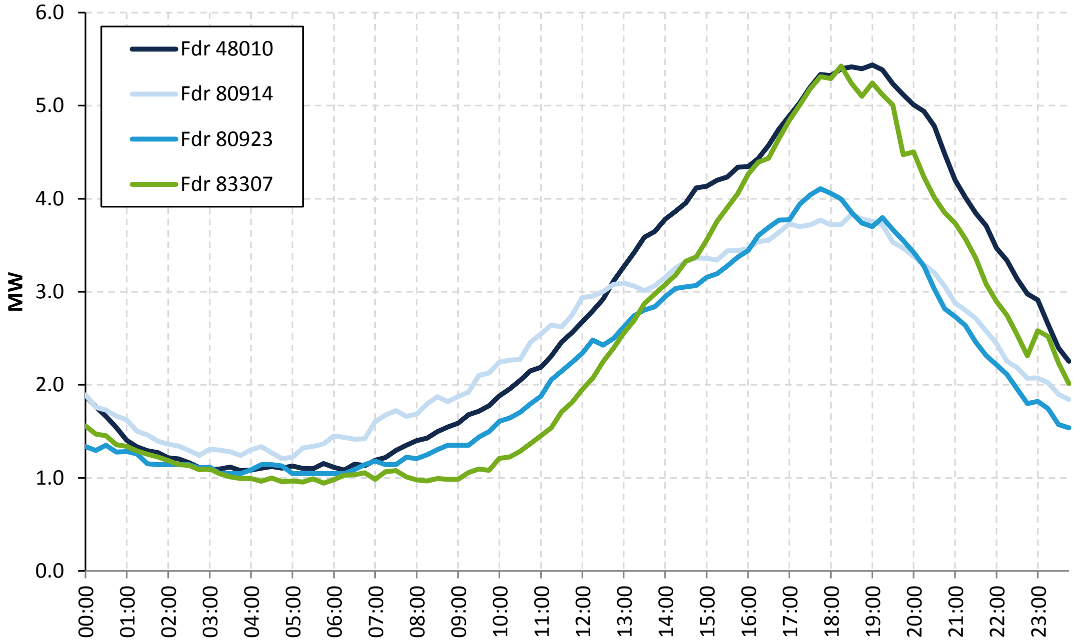


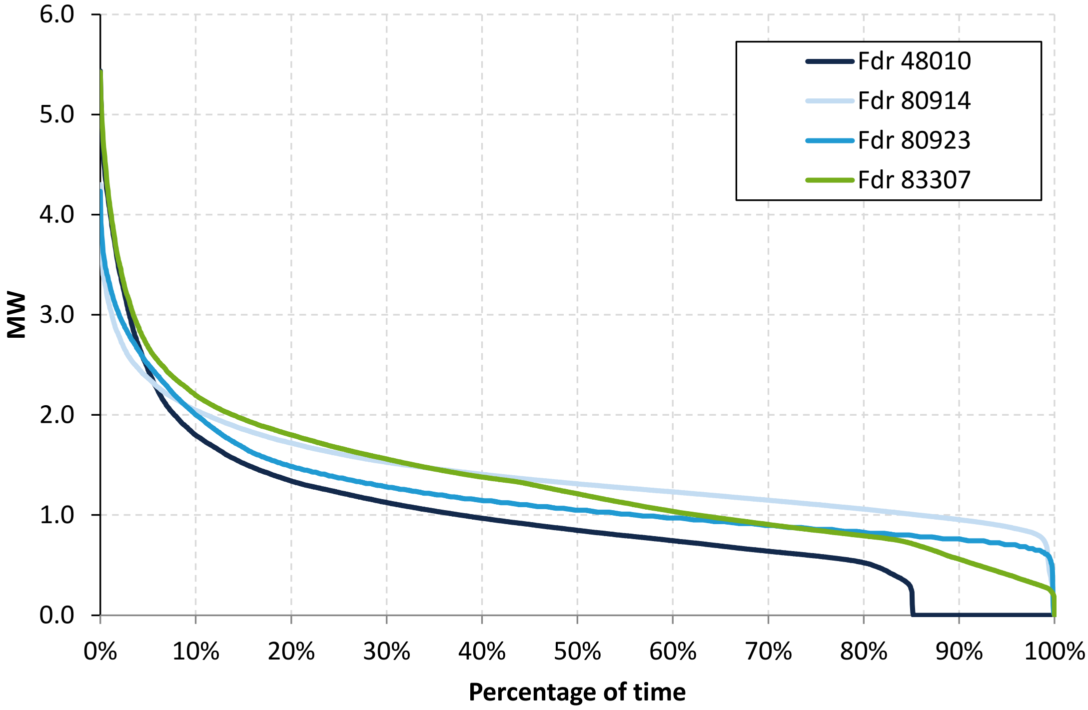
Figure 2 following displays the demand profile for each of the four feeders for a peak day during the 2018/19 summer period. This chart shows that maximum demand on all feeders is coincident on the four feeders, representing the mainly residential load where demand peaks in the early evening on hot days. Analysis on the demand during the maximum demand days in 2018/19 show that peak loads largely fall between 5pm and 8pm.

Figure 2 – 2018/19 peak day demand



The load distribution curve (Figure 3 below) for each feeder highlights the 'peakiness' of the customers demand on each feeder. The load duration curve is constructed by sorting the feeder's 15-minute electricity data from highest to lowest.

Figure 3 – load duration curves from Gillieston Heights feeders



Analysis of the 2017/18 feeder demand data shows that:

- Feeder 48010, 7% of the customers demand (374kVA) is only required for 0.1% of time (35 hours)
- Feeder 80914, 16% of the customers demand (606kVA) is only required for 0.1% of time (35 hours)
- Feeder 80923, 10% of the customers demand (371kVA) is only required for 0.1% of time (35 hours)
- Feeder 83307, 7% of the customers demand (360kVA) is only required for 0.1% of time (35 hours)

From the figures above, it is clear that demand reductions or embedded generation support is required for only a small number of hours each year.

3 Characteristic required of a non-network option

3.1 Timing and quantity of demand reductions

This section describes the technical characteristics of a non-network option and is based on the required demand reductions described in section 2.1 and the customer demand characteristics described in section 2.3.

Peak demand occurs in summer and the existing summer load profiles shown in figure 2 indicate the time of day where peak loads occur on the four 11kV feeders. The load profile peaks in the evening indicating predominantly residential load at a maximum between 4pm and 9pm.

A comparison of historical maximum demand across summer and winter indicates that summer maximum demand is, on average, 38% higher than in winter. There are no forecast winter capacity constraints, hence, the technical non-network option characteristics below focus solely on summer requirements.

As a result, all non-network options must reduce peak demand during the following period:

Table 5 – Non-network option technical characteristics

Parameter	Target
Time of year	1 November – 31 March
Time of day	4pm to 9pm
Season	Summer
Day type	Working days & non-working days
Weather conditions	Hot days
Demand reduction required	Refer table 2

As part of the requirement of this RFP, at least one test event is required prior to the start of summer 2019/20. Specific timing will be agreed with providers as part of the contract negotiations.

In addition to the test, Ausgrid envisages that there may be in the order of 4 – 10 peak events, where project proponents must supply the demand management reductions required.

4 Financials

4.1 Funds Available

Ausgrid is required under the National Electricity Rules (NER) to ensure investments in the distribution network are prudent, with the preferred option being the one that represents the best net economic value to achieve the desired outcome. This section sets out the funds that Ausgrid has determined are available in the form of incentive payments for non-network options to address the identified network need outlined in section 2.

The funds available have been determined by Ausgrid based on financial modelling of cost savings due to deferring capital expenditure and assuming the capacity constraints are able to be addressed using non-network options. The net present value of deferring the network solution each year is calculated, with the added inclusion of an option value in the assessment (for every year of deferral, the capital cost of the supply-side solution decrease by 5%). In this case the preferred supply-side solution involves the construction of a new interconnector between two feeders and the installation of voltage regulation on another feeder, with an estimated cost of $700,000.

The net present value from deferral of the network investment determines the funds available for demand management, as presented in table 6. For a one year deferral of the network investment, 190kVA of load reductions are required, with $51,000 available.

Deferring the network investment for two years will require a 190kVA reduction in year one and between 790 – 1000kVA of load reductions in year two, with a total of $98,000 available for the two years.

Deferring the network investment for three years will require a 190kVA reduction in year one, between 790 – 1000kVA of load reductions in year two and between 1400 – 1700kVA of load reductions in year three, with a total of $141,000 available for the three years.

The demand reduction required for each year of deferral (and therefore the funds available) is based on the current demand forecast. Any future changes to the required demand reductions and/or the funds available will be negotiated with project proponent(s) at a later stage if required.

Table 6 – Demand management funds available

Number of years deferred	Demand reduction required (kVA)			Funding available (whole of program)
	Year 1	Year 2	Year 3	
1	190			$51,000
2	190	790 – 1000		$98,000
3	190	790 – 1000	1400 – 1700	$141,000

Based on the network need and load profiles described above, Ausgrid envisages that a number of non-network solutions may be viable, and that incentive payments can be structured differently for different types of non-network solutions.

5 Market Engagement Process

5.1 Procurement Platform

Ausgrid is undertaking market engagement via Ausgrid's Tenderlink portal at https://www.tenderlink.com/ausgrid/ (Tenderlink Ref: **AUSGRD-859530**) where this RFP and the associated data pack can be found. To download the RFP, you must be registered which is free.

For all questions about the Gillieston Heights RFP, please direct them through Ausgrid's Tenderlink portal. For any general questions about Ausgrid's demand management process, contact us at demandmanagement@ausgrid.com.au.

5.2 Schedule

The estimated timeline of key milestones for this project are as follows:

#	Milestone	Date	Comments
1	RFP release	30 Apr 2019	This document.
2	RFP response due	28 May 2019	Market responses to RFP
3	Contract issue	June 2019	Contract offer to successful bidder(s)
4	Contract execution	June 2019	
5	Year 1 Testing	October 2019	
6	Year 1 period start	1 Nov 2019	
7	Year 1 period end	31 Mar 2020	
8	Year 2 Testing	October 2020	
9	Year 2 period start	1 Nov 2020	
10	Year 2 period end	31 Mar 2021	

5.3 Data pack

Ausgrid provides the following information in a data pack accompanying this RFP to assist demand management proponents with their submission:

- Electricity interval data for 11kV feeders; and
- Google Earth (kmz) files to indicate the target areas.

The data pack is available via Ausgrid's Tenderlink portal.

6 RFP Submission Requirements

6.1 Proposal Submission

Ausgrid is inviting interested parties to submit a written proposal by 28 May 2019. Proposals should address the following:

- Contact details of the company or person making the submission;
- A demonstration that proponents have the capability and capacity to deliver demand management services; such as information on the background to the company, key personnel and their previous experience and previous track record of work in the delivery of non-network solutions;
- Details of the technology, equipment or service that will achieve the required reductions in grid demand. As an example, this could include energy management services, aggregation of dispatchable demand management, a technology solution or embedded generation. For each type of solution proposed, the following information *must* be provided:
    - Type of solution;
    - Number of customers, location of customers, load reduction per customer, total load reduction proposed; and
    - Any limits on the number of times the initiate can be called per year (excluding tests).
- Time required to implement the measures and notice period required to activate the demand management solution or embedded generators during a peak event;
- The proposed measurement and verification methodology to quantify the size of demand reductions. Methodologies should be guided by the International Performance Measurement & Verification Protocol; and
- The required payments from Ausgrid for the proposed solutions, including payment structures. All costs and payments *must* be split clearly, for example by establishment fee, test fee, fee per dispatch etc.

6.2 Evalulation and selection criteria

Ausgrid will evaluate the proposals received by this RFP, based on evaluation against the following criteria:

- Experience in delivering non-network solutions;
- Ability to achieve the demand reductions that are proposed;
- Cost effectiveness of the proposed demand reductions; and
- Timing of the delivery of non-network solutions to meet peak load reductions required in 2019/20 and beyond.

Proponents may be invited to further discussions with Ausgrid as part of the evaluation process.

Ausgrid