Addressing increased customer demand requirements in the Gillieston Heights area

PROJECT ASSESSMENT REPORT

SEPTEMBER 2019

Ausgrid

Contents

Executive Summary

This Project Assessment Report has been prepared by Ausgrid and represents the final step in Ausgrid's assessment of options for ensuring the growing customer demand in the Gillieston Heights supply area is addressed in the most economic manner.

Ausgrid identified an emerging network constraint associated with three interconnected 11kV feeders (Metford 83307, Telarah 48010 and Kurri 80923). The proposed preferred network option involves the installation of new underground cables, reconductoring and augmentation of identified sections of overhead lines in the Gillieston Heights area for an estimated cost of $695,000.

A preliminary assessment indicated there was potential to use demand management techniques to defer the proposed supply-side solution. In early May 2019, Ausgrid issued a Request for Proposals (RFP) seeking market submissions to address the identified need. Only one submission was received, which was assessed as being non-viable.

Following the unsuccessful market engagement process, Ausgrid assessed the feasibility of several internally developed solutions based upon past demand management trials and projects. Assessed options included power factor correction, non-residential demand response and residential air-conditioner (AC) load control.

A one-year deferral of the network investment using residential air conditioner load control was found to offer a viable, cost efficient alternative and was selected as the preferred solution. And while deferral of the network investment for more than one year was not determined to be cost effective, the option for further deferral of the investment will be considered in early 2020 before committing to the network investment.

Ausgrid intends to deliver the demand management solution in 2019. In particular, we intend to make offers to customers in September 2019 so as to ensure that air conditioner load control equipment is installed and operational November 2019 for availability in Summer 2019/20.

1 Introduction

This Project Assessment Report (PAR) has been prepared by Ausgrid to report on the assessment of an identified network need in the Gillieston Heights area in the Maitland LGA of NSW.

Ausgrid identified an emerging network constraint associated with three interconnected 11kV feeders (Metford 83307, Telarah 48010 and Kurri 80923). 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.

A preliminary assessment indicated there was potential to use demand management techniques to defer the proposed supply-side solution. In early May 2019, Ausgrid issued a Request for Proposals (RFP) seeking market submissions to address the identified need.

1.1 Purpose of this document

The purpose of this Project Assessment Report is to:

- Describe the identified need;
- Detail the demand management options considered;
- Present the results of the cost benefit assessment; and
- Identify the preferred option.

1.2 Contact details

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2 Description of Identified Need

2.1 Overview of Gillieston Heights Area

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

Image 1: Gillieston Heights location

2.2 Description of capacity constraint

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

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 of the forecast capacity constraint for all feeders.

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.

Table 2 ‑ Demand reductions required

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

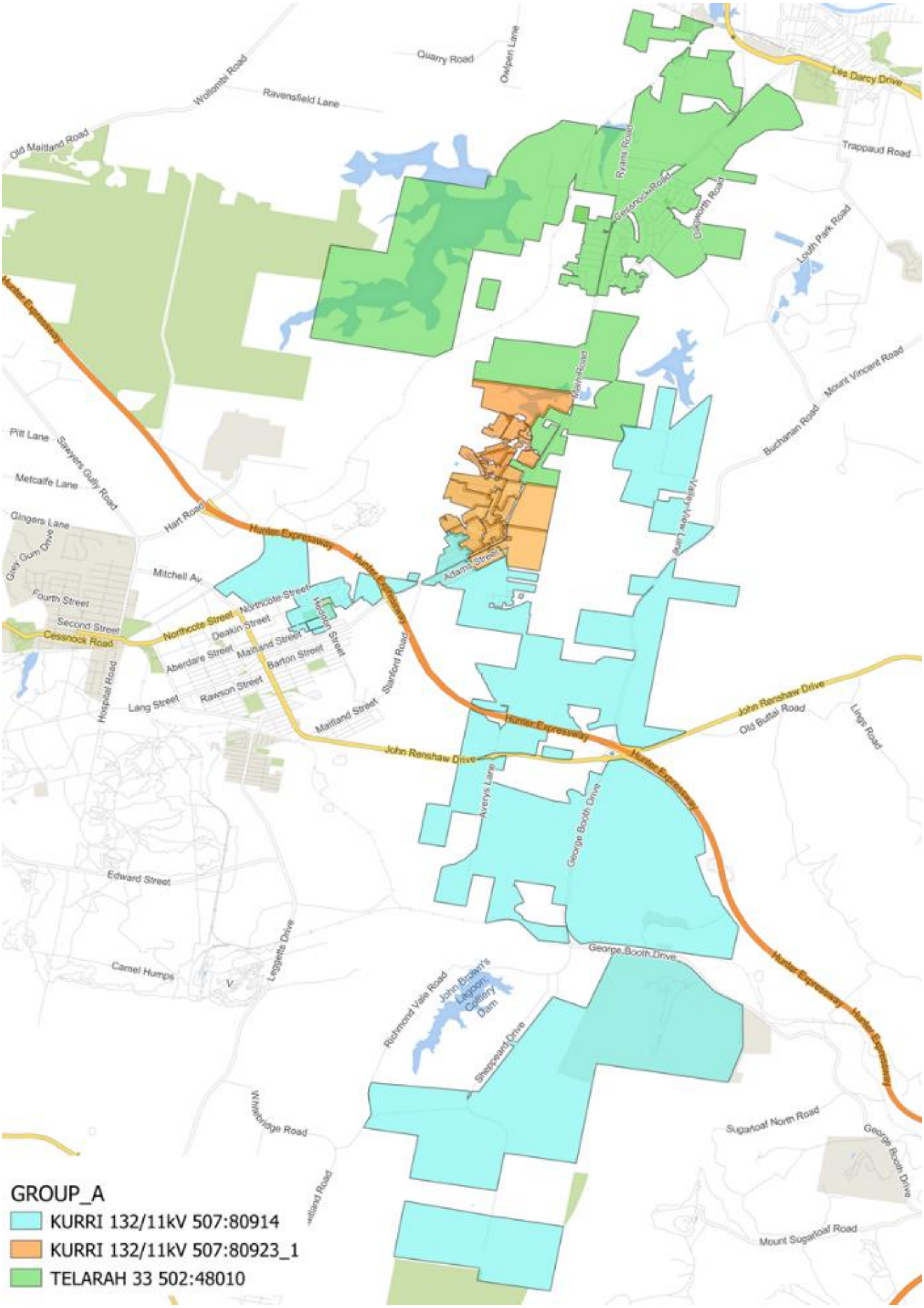
2.3 2019/20 requirement

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 detailed in the table and image following.

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%

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



2.4 2020/21 and 2021/22 requirement

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 customers supplied from feeder 83307. Customers in group B consist of those customers in group A, plus an additional set of customers.

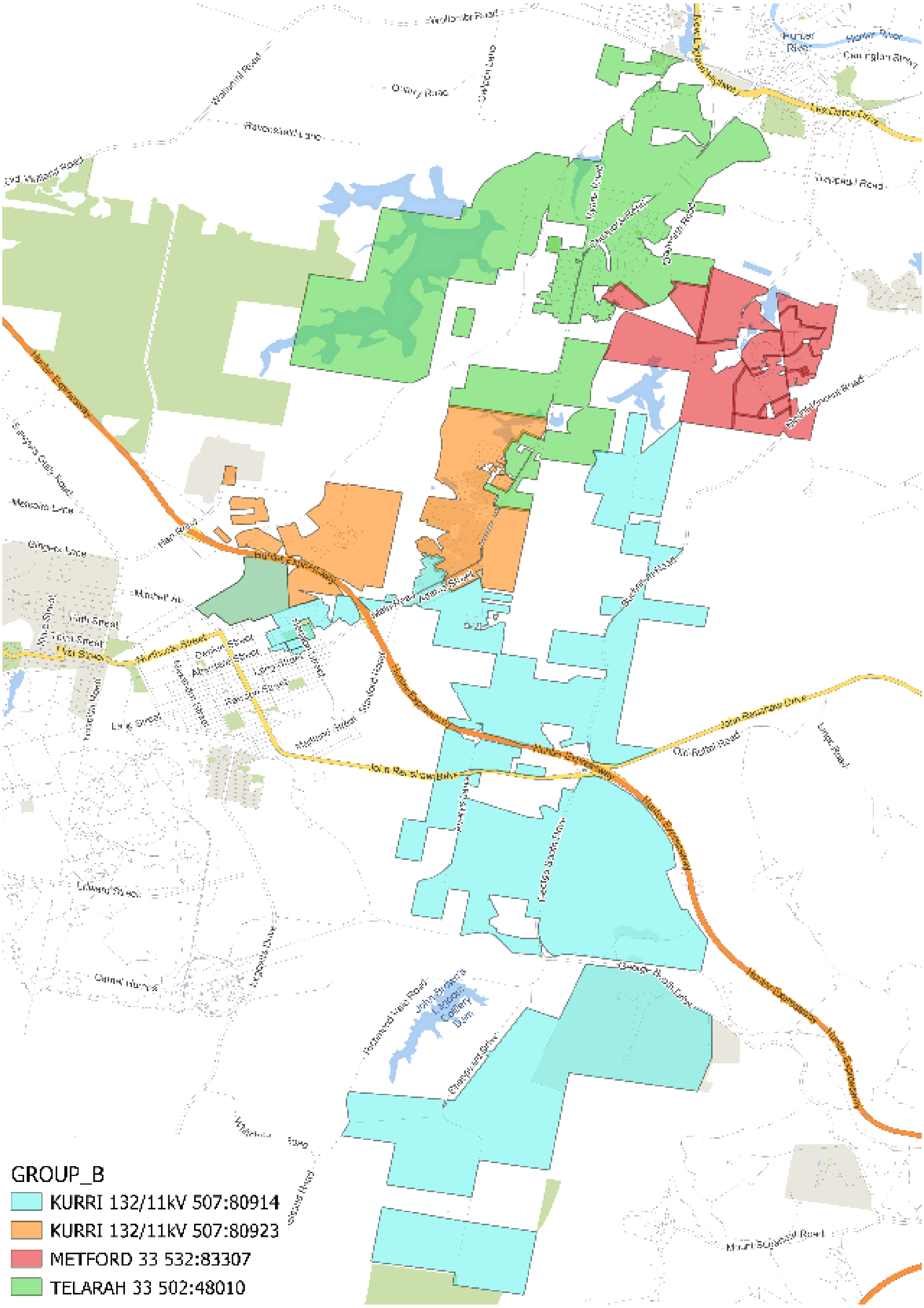
The customers in the Group B region are described in Table 4 below.

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%

The Group B region is shown in image 3 following.

Image 3: Group B region map - 2020/21 and 2020/21 network need area



2.5 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.

Figure 1 below shows the combined demand on the four feeders, to give an indication of the seasonal timing of peak demands. Note 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

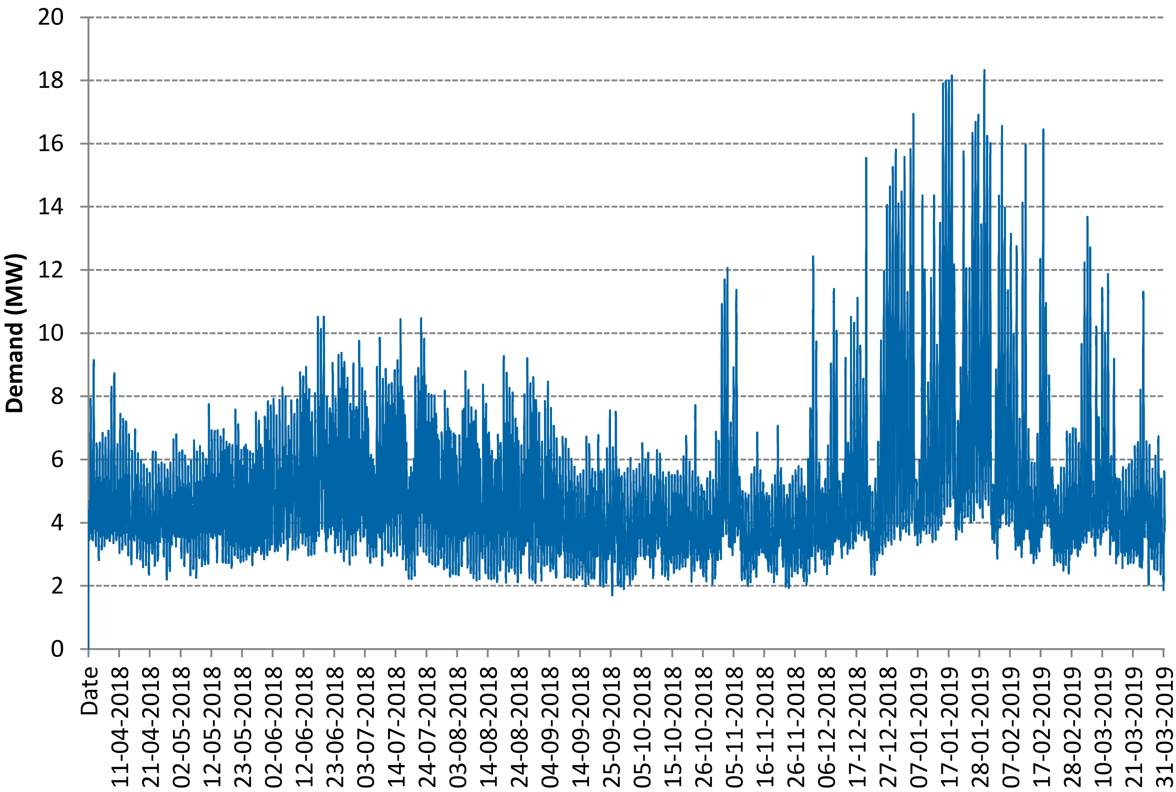
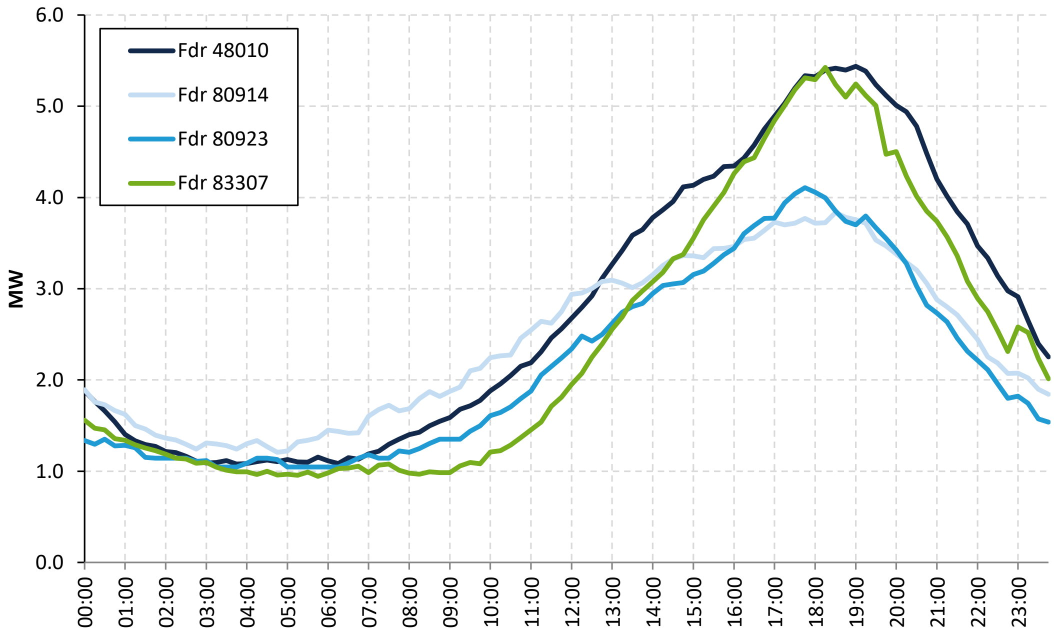


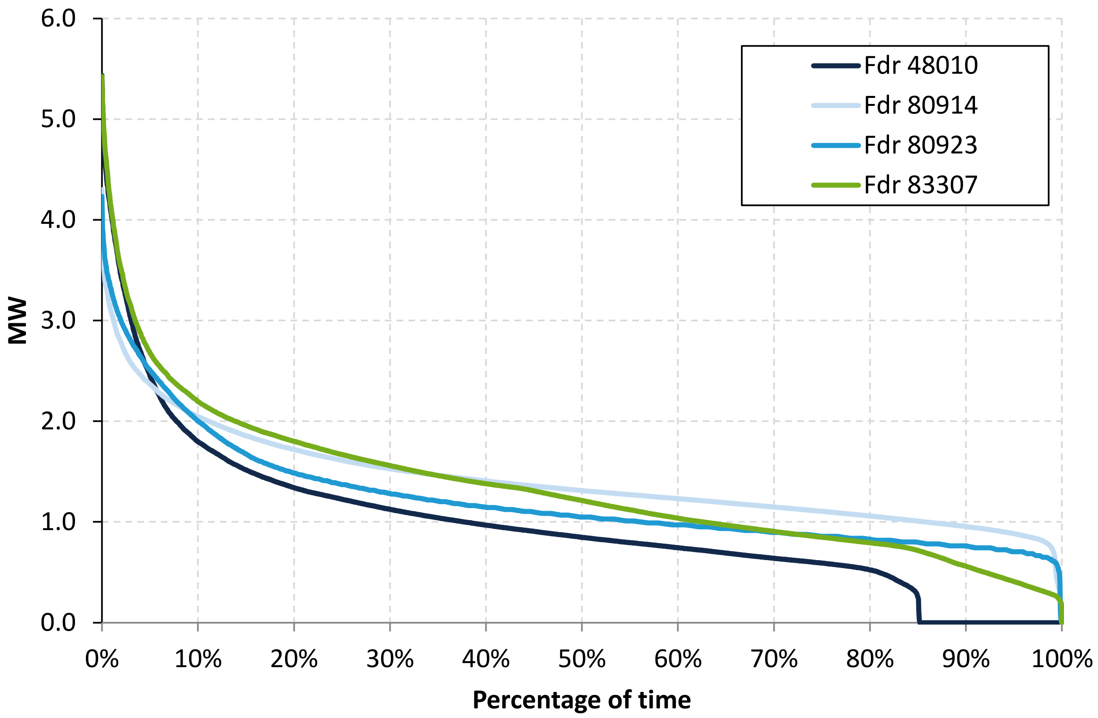
Figure 2 following displays the demand profile for each of the four feeders for a peak day during the 2018/19 summer period. This chart shows that maximum demand on all feeders is coincident on the four feeders, representing the mainly residential load where demand peaks in the early evening on hot days.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



2.6 Proposed preferred network option

The proposed preferred network option involves the installation of new underground cables, reconductoring and augmentation of identified sections of overhead lines in the Gillieston Heights area for an estimated cost of $695,000.

3 Demand Management Assessment

3.1 Initial cost benefit analysis

The funds available for non-network solutions were determined by Ausgrid based on technical and financial modelling of the likely costs and benefits of implementing non-network solutions to defer capital expenditure. The net present value of all costs and benefits associated with deferring the proposed network solution for either 1, 2 or 3 years were compared against the without-deferral case to determine the fund available for DM. The assessment was carried out using NPV analysis over a 20 year time horizon and included the following costs and benefits which accrue to customers:

- Benefit: Avoided unserved energy (reduced involuntary load shedding) due to reducing grid-supplied demand for the deferral scenarios and implementation of the proposed preferred supply option based on a VCR of $40,000/MWh;
- Benefit: Terminal (depreciated) value of capital assets in year 20 based on an assumed nominal asset life of 40 years;
- Benefit: An estimated option value where for every year of deferral, the capital cost of the supply-side solution decreases by 5%;
- Cost: Capital cost of proposed preferred supply option; and
- Cost: Estimated costs of demand response (DR).

The table below summarises the outcomes of the cost benefit assessment that was included in the Request for Proposals (RFP), to achieve 1, 2 or 3 years deferral of the supply-side project. The present value (PV) figures below were based on a discount rate of 3.86% used in NPV analysis.

Deferral Years	MVA Reduction Required	Timing of DM reduction	PV of DM Budget available ($)	PV of Estimated DM cost ($)	Est cost as % of budget	DM Funds available ($/kVA/yr)
1	0.2	2019/20	$54,000	$35,000	64%	$282
2	0.8	2020/21	$103,000	$126,000	122%	$66
3	1.4	2021/22	$149,000	$261,000	175%	$36

The estimated cost of non-network alternatives was estimated to be 64%, 122% and 175% of the available funds for 1, 2 and 3 year deferral scenarios, respectively. Based on this assessment, Ausgrid determined that demand management could potentially defer the proposed preferred network option.

Further, taking into account both the MVA reduction required and DM budget available, Ausgrid considered a 1 year deferral as the most attractive deferral scenario as it offered the highest NPV of around $329,000 when compared against a “do-nothing” scenario. Applying sensitivity analysis over key inputs and assumptions in the cost benefit assessment for a 1 year deferral, namely the cost of the proposed preferred supply option and option value to account for uncertainty, resulted in $37,000 to $66,000 as an available project budget range.

4 Assessment of DM options

This section describes the credible demand management (non-network) options considered.

4.1 Options considered

Option 1 –Residential behavioural demand response

In early May 2019, Ausgrid issued a Request for Proposals (RFP) seeking market submissions to address the identified need using the procurement portal Tenderlink. Only one submission was received in response.

Option 1 proposed a residential behavioural demand response type solution. The proposal did not include the costs for activities such as marketing and customer acquisition, smart meter installation, customer incentive payments and project management.

These additional costs increased the total cost to about 220% of the upper limit of the available project budget. This assessment uses an updated discount rate of 3.22% based on Ausgrid's 2019-24 regulatory determination.

Based on this assessment, Option 1 was considered not economically viable.

Option 2 – Customer power factor correction

Of the 84 non-residential customers in the affected network area, around 4 are on a kVA demand tariff. Analysis of customer interval data indicates there is no technical or commercial potential since all customers on a kVA demand tariff have power factors over 0.96.

Option 3A – Residential air-conditioner demand response

The feeder demand profiles strongly indicates high levels of ownership of air conditioners in the area. Ausgrid past CoolSaver trials indicated that the use of residential air-conditioning (AC) load control to supply the necessary demand reductions was potentially feasible and cost effective. This solution involves the following:

- Offer incentives (upfront sign-on bonus and post-season payment) to customers in the affected network area to participate in the load control program;
- Install Demand Response Enabling Devices (DREDs) on participating customer air-conditioner (AC) units; and
- When required, activate the power saving modes on the AC units for participating customers via a ripple control signal to the DREDs from Ausgrid's control room (same system used to control ½ million residential hot water heaters).

Option 3B – Residential battery demand response

A total of about 15 customer battery systems were identified as connected to the Ausgrid network in the affected area with one identified as participating in a Virtual Power Plant (VPP). While the potential demand reductions from leveraging the available battery systems are small, the cost might be low considering the current operation of the Ausgrid VPP project.

4.2 Preferred option

A proposed project based upon Option 3 was developed and estimated to have a project cost of $49,000 to $64,000 including purchase and installation of DREDs, marketing, customer incentive payments and project management. This solution principally involves the use of residential air conditioner demand response, with the potential for a small element of support from residential battery demand response.

This option is expected to deliver net present benefits in the range $290,000 to $460,000 when compared against a “do-nothing” scenario. These NPV figures use an updated discount rate of 3.22% based on Ausgrid’s 2019-24 regulatory determination.

Based on cost-benefit assessment, Ausgrid considers this solution to be an efficient non-network option to reduce load at risk on the relevant 11kV feeders for the upcoming summer 2019/20, deferring the proposed supply-side solution until summer 2020/21. And while deferral of the network investment for more than one year was not determined to be cost effective, the option for further deferral of the investment will be considered in early 2020 before committing to the network investment.

Option 3 is the preferred option and, accordingly, Ausgrid is proceeding with development of this project as an **eligible demand management proposal** under the DMIS guidelines.

Ausgrid