Feeder demand management program

UE BUS 9.03 - Feeder demand management - Jan2020 - Public

Regulatory proposal 2021–2026

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Contents

1 Overview

Business	United Energy
Title	Feeder demand management program
Project ID	UE BUS 9.03 - Feeder demand management - Jan2020 - Public
Category	Operating expenditure
Identified need	Risk of overload on HV feeders could lead to supply outages when the demand on the feeder exceeds its thermal capacity with the network in its normal configuration, or for a single contingency such as a fault on an adjacent feeder.
Recommended option	Option 3—undertake demand management when it is economically viable
Proposed start date	2021/22
Supporting documents	1. UE MOD 9.05 - Demand management HV feeder - Jan2020 - Public 2. UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public

This business case considers whether demand management is an economically viable solution to addressing the risk of overload on high-voltage (**HV**) feeders. Table 1 outlines the HV feeders on which demand management is viable, and the demand management cost for which we are seeking a positive step change to our base year operating expenditure.

Table 1 HV feeder demand management step change ($ 000, 2019)

Project	Primary feeder	2021/22	2022/23	2023/24	2024/25	2025/26	Total
FSH24 new feeder	FSH 33	-	41	46	51	56	194
HGS11 new feeder	HGS 33	45	54	62	71	-	231
LD34 new feeder	LD 06	-	-	-	-	39	39
MGE new feeder	MGE 12	36	44	53	-	-	132
EB new feeder	RWT 34	-	-	-	46	-	46
OE new feeder	OE 04	37	-	-	-	-	37
OR new feeder	OR 24	22	41	60	-	-	122
RBD11 extension	STO 14	-	42	66	-	-	108
WD new feeder	WD 14	-	-	-	21	-	21
Total		**140**	**221**	**286**	**189**	**95**	**931**

Notes: Demand management was previously applied on the MGE feeder. Demand on the feeder dropped and the demand management program was stopped (demonstrating the benefit of our demand management program in ensuring only efficient investments are made). We are expecting this demand management program will need to resume in 2020, but only the costs from 2021 are included in this business case.

Source: United Energy

2 Background

Demand management can be used to (temporarily or permanently) defer augmentations. The advantages of demand management are that it:

- can be less costly than a capital solution
- empowers and rewards customers for adjusting their energy patterns to support the efficient operation of the network
- can be provided incrementally as demand grows and stopped if it declines
- provides option value—it delays long-term investments that are generally irreversible. This delay provides time to see whether maximum demand forecasts eventuate and whether another solution to the identified need becomes viable.

The potential disadvantages of demand management are:

- if maximum demand exceeds its forecast, the amount of contracted demand management may be insufficient. In contrast, a feeder augmentation is sized to accommodate multiple years of growth for close to no additional capital cost.
- there is a risk contracted demand management does not eventuate (i.e. customers may not reduce their demand either for the magnitude or the duration necessary to address the need).

These risks can lead to supply outages and financial penalties under the Service Target Performance Incentive Scheme (**STPIS**).

3 Identified need

Risk of overload on HV feeders could lead to supply outages when the demand on the feeder exceeds its thermal capacity with the network in its normal configuration, or for a single contingency such as a fault on an adjacent feeder. The need to correct these potential overloads is not established in this business case. Rather, our approach to determining when potential overloads need to be corrected is outlined in the augmentation chapter in our regulatory proposal.

The identified need addressed by this business case is to ensure the most efficient solution to addressing overload risk on HV feeders is adopted. Therefore this business case describes our approach to determine when demand management is an economically viable alternative to capital investment.

4 Options analysis

We have considered two options in this business case as outlined below.

4.1 Option one—capital investment

Option one is to undertake capital investment to address overload risk. This may not be the most efficient option, as discussed below.

4.2 Option two—demand management

Option two is to undertake demand management on HV feeders where it is economically viable and otherwise undertake a capital solution.

To assess demand management viability, we compared the annualised capital cost of addressing a feeder's overload risk to the cost of demand management, where the:

- annualised capital cost is the real weighted average cost of capital multiplied by the capital cost plus depreciation
- demand management cost is the benchmark demand management unit rate multiplied by the excess demand on the feeder plus a contingency. This is discussed below.

We have undertaken this assessment on feeders where there is an identified need to correct overload risk arising over 2020–2025/26.[1] An illustrative example of the approach is outlined in appendix A.

4.2.1 Demand management unit costs

We have led the industry with the implementation of several successful demand management programs since 2014. To forecast demand management costs, we have applied a unit rate based on actual demand management programs we have undertaken.[2] This unit rate has also been independently reviewed and compared to the demand management rates of other distributors by CutlerMerz.

CutlerMerz have found our rate is at the lower end of the range of rates adopted by other distributors, and recommended our rate be used for assessing the viability of demand management projects.[3] The demand management unit cost calculation is outlined in detail in appendix B and summarised in table 2.

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1 The demand management costs for feeders on which demand management begins in 2020 but continues over the 2021–2026 regulatory period are not included in our base year operating expenditure. Therefore we have included the forecast demand management costs arising in 2021–2026 for HV feeders where demand management begins in 2020. Note this business case does not recover costs arising prior to the 2021–2026 regulatory period.

2 This rate has been used consistently across United Energy demand management programs.

3 UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public

Table 2 Demand management unit rate ($ 000, 2018)

Demand management type	Program	Cost/MVA/year	Average	Weighting	Contribution to unit cost
Residential	Summer Saver	133.9	133.9	18%	24.1
Commercial, industrial	Hastings to Rosebud (Community Grid)	67.5	74.4	82%	61.0
	MGE 12	81.3			
Total demand management unit cost					**85.1**

Source: United Energy

4.2.2 Contingency

As discussed in section 2, a capital solution addresses potential overloads. However, there is a greater risk demand management will not fully alleviate an overload potential. Therefore a contingency—i.e. reducing demand below the level that triggers an overload—is needed to mitigate these risks.

The higher the contingency, the fewer demand management projects will be viable because the amount, and hence cost of demand management increases. For this reason we have selected a small contingency of 4% to demonstrate our commitment to, and maximise the number of HV feeders eligible for demand management. This margin represents an acceptable financial risk under the STPIS.

The contingency for years subsequent to the initial year is zero (i.e. the additional demand management required is the forecast maximum demand growth).

4.2.3 HV feeders for which demand management is viable

Applying the approach described, we have identified the feeders in table 3 for which demand management is a viable alternative to augmentation in that it defers the augmentation by at least one year.

Table 3 Feeders on which demand management is economically viable ($ 000, 2019)

Project	Capital cost	# years deferred	Total annualised capital cost (over deferral period)	Total DM cost (over 2021–2026)	Net savings from DM
FSH24 New Feeder	1,618	4	240	194	46
HGS11 New 22kV feeder	2,010	4	298	231	66
LD34 New feeder	1,503	1	56	39	16
MGE new feeder	1,511	3	168	132	36
New EB Feeder	1,510	1	56	46	10
New OE Feeder	1,086	1	40	37	3
OR new feeder	1,627	3	181	122	58
RBD11 Feeder Extension	2,071	2	153	108	45
WD new feeder	1,030	1	38	21	17
Total	**13,966**	**20**	**1,230**	**931**	**298**

Source: United Energy

More information is available in the demand management HV feeder model.[4] We have updated our capital investment plan to account for this demand management program. In our model, feeder investments are first outlined in the years in which the investment is needed, assuming no demand management program. We have then included an adjustment line that backs-out capital investments where demand management has delayed the investment need and, where the investment cannot be deferred outside of the 2021–2026 regulatory period, put the investment in the subsequent years where the investment will take place as a result of demand management.

4 UE MOD 9.05 - Demand management HV feeder - Jan2020 - Public

5 Recommendation

We recommend deferring augmentation and adopting demand management on HV feeders where it is economically and technically viable to do so (option three). Given we have not applied our Summer Saver demand program to feeders previously, doing so now requires incremental operating expenditure above our 2019 base operating expenditure. The required incremental operating expenditure is shown in table 4.

For more information refer to the demand management HV feeder model.[5]

Table 4 HV Feeder demand management step change ($ 000, 2019)

Project	Primary feeder	2021/22	2022/23	2023/24	2024/25	2025/26	Total
FSH24 new feeder	FSH 33	-	41	46	51	56	194
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Notes: Demand management was previously applied on the MGE feeder. Demand on the feeder dropped and the demand management program was stopped (demonstrating the benefit of our demand management program in ensuring only efficient investments are made). We are expecting this demand management program will need to resume in 2020, but only the costs from 2021 are included in this business case.

Source: United Energy

5 UE MOD 9.05 - Demand management HV feeder - Jan2020 - Public

A Illustrative example

An illustrative example of our approach to identifying demand management opportunities is shown in table 5. The example assumes a maximum feeder load of 10 MW.

Table 5 Illustrative example ($ 000)

Year	1	2	3
Forecast feeder load (MW)	9.5	10.0	10.5
Required demand management (including 4% initial demand margin) (MW)	-	0.4	0.9
Capital solution cost	1,500.0		
Annualised cost of capital solution[6]	-	55.6	55.6
Cost of demand management ($85,087/MW/year)	-	34.0	76.6
Demand management economically viable?	-	Yes	No
Total cost of demand management			**34.0**

Source: United Energy

In this example, demand management can defer augmentation for one year.

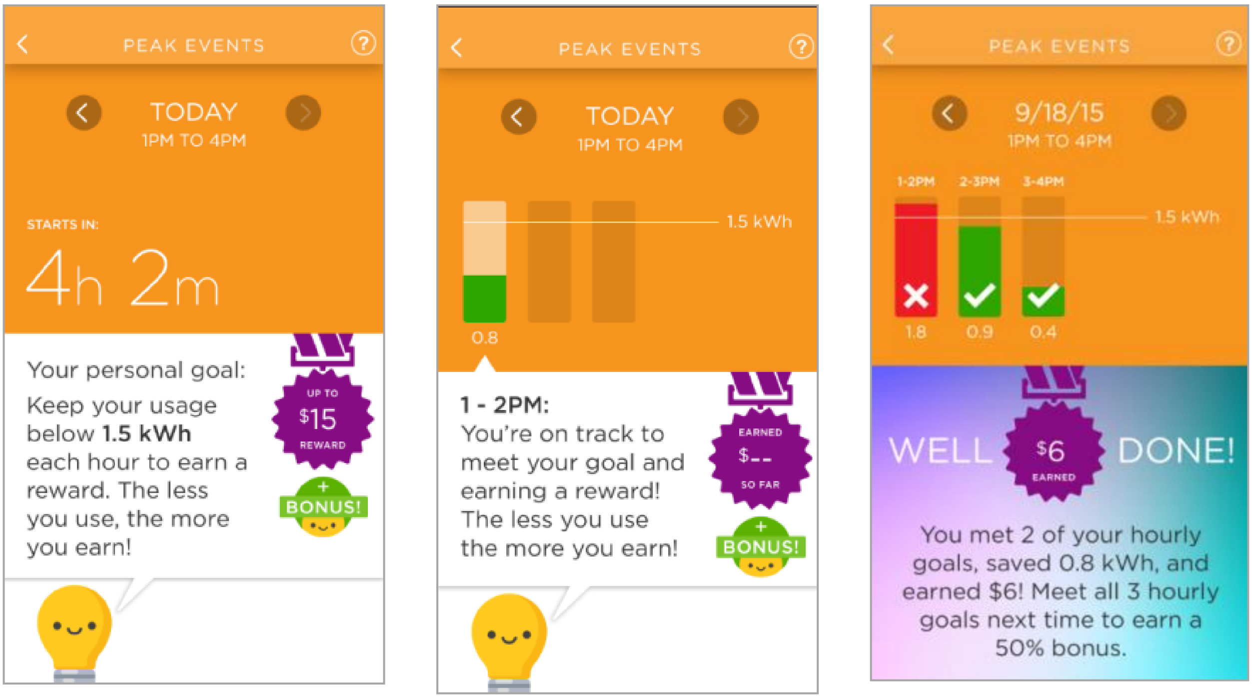
6 Return on capital of 2.75% and return of capital.

B Demand management unit costs

The actual demand management programs we have used to set a benchmark unit rate are:

- Rosebud to Hastings line lower Mornington Peninsula (Community Grid) project—after conducting a RIT-D and Non-Network Options Report on which multiple offers for demand management were received, we entered into a network support agreement with GreenSync for around 13 MW of demand management. This agreement (and pricing) was predominately targeted at receiving demand management from commercial and industrial customers, however, diesel generators are also currently being used.
- MGE 12 distribution feeder—we had a network support agreement with GreenSync to provide 0.8 MW of management. Demand management is predominantly offered by commercial and industrial customers under this agreement.
- Summer Saver program—after a successful trial in 2016-2017, this program forms part of our business as usual practices. It has signed up 900 residential customers in constrained network areas to reduce their load at peak times. Participants receive payments and rewards for responding to an 'event day'. The program uses Advanced Metering Infrastructure to measure customers' response, with an average energy reduction per event of over 1MWh. Figure 1 summarises the Summer Saver program.

Figure 1 Summer Saver program



Source: United Energy

We have weighted the residential, and commercial and industrial demand management program costs based on our expectation of these customers' contribution to demand management. This has been undertaken via the following steps:

1. residential demand response—the number of residential customers in our network is multiplied by the rate of customers that, once approached, participate in our Summer Save program. This provides the expected number of residential customers that would participate in demand response. This is multiplied by amount of demand response we receive from an average customer participating in the program to provide the overall total residential demand response available.

2. commercial and industrial demand response—the same approach as above was applied to commercial and industrial customers.
3. percentage of demand response provided by each customer group—we divided the residential demand response from 1, by the total demand response (the sum of 1 and 2) to determine the percentage of demand response that is expected to be provided by residential customers. The same was undertaken for commercial and industrial customers (which is the inverse of the residential percentage).

The results are shown in table 6.

Table 6 Demand management unit rate ($ 000, 2018)

Demand management type	Program	Cost/MVA/year	Average	Weighting	Contribution to unit cost
Residential	Summer Saver	133.9	133.9	18%	24.1
Commercial, industrial	Rosebud to Hastings	67.5	74.4	82%	61.0
	MGE 12	81.3			
Total demand management unit cost					**85.1**

Source: United Energy

This unit rate has also been independently reviewed and compared to the demand management rates of other distributors by CutlerMerz. CutlerMerz have recently undertaken work for three distributors that are exploring demand management as an option for alleviating network constraints. They have found our rate is at the lower end of the range of rates adopted by other distributors, and recommended our rate continue to be used for assessing the viability of demand management projects.