Lower Mornington Peninsula demand management program

UE BUS 9.02 - Lower Mornington Peninsula demand management - Jan2020 - Public

Regulatory proposal 2021–2026

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Contents

1 Overview

Business	United Energy
Title	Lower Mornington Peninsula demand management program
Project ID	UE BUS 9.02 - Lower Mornington Peninsula demand management - Jan2020 - Public
Category	Operating expenditure
Identified need	Maintain supply security (voltage and capacity) to the lower Mornington Peninsula area
Recommended option	Option 3—enhance demand management program
Proposed start date	2021/22
Supporting documents	1. UE MOD 9.04 - Demand management Lower Mornington - Jan2020 - Public 2. UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public 3. UE ATT105 - Assessment Lower Mornington Peninsula - May2016 - Public 4. UE MOD 9.07 - Maximum demand forecasts - Jan2020 - Public

In 2016 we completed a Regulatory Investments Test for Distribution (**RIT-D**) that established a need to invest in the lower Mornington Peninsula to maintain supply security (voltage and capacity).[1] The net market benefit from doing so was found to be around $32 million. In accordance with the RIT-D, we implemented a four year demand management program in 2018 that runs through 2021. This program was to defer $29.5 million ($2015) of capital expenditure until 2022.[2]

By virtue of having deferred the capital solution, we now have updated actual demand and forecasts with which to plan ongoing supply requirements for the area. The updated forecasts demonstrate the strong trend in growth has continued over the last few years, however, demand is now forecast to flatten over the next few years. This has created an opportunity to continue the demand management program and further defer the capital expenditure to the 2026–2030 regulatory period.

We are seeking a step change to our 2019 base operating expenditure to enhance and continue our demand management program once the current contract with GreenSync Pty Ltd expires. The step change from the 2019 base year costs is needed because:

- more demand management is required to meet the growth in maximum demand
- the current demand management contract costs understated the actual cost of demand management for which GreenSync has had to absorb the cost overrun.

The operating expenditure step change is outlined in table 1.

Table 1 Recommended option: expenditure profile ($ million, 2019)

Expenditure forecast	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Operating expenditure step change	0.9	0.9	1.2	1.2	1.2	5.4

Source: United Energy

The allowance to continue this demand management program (including the above step change to 2019 base year costs) remains within the annualised cost of augmenting the network, and therefore remains consistent with the economic prudency test undertaken in the RIT-D.

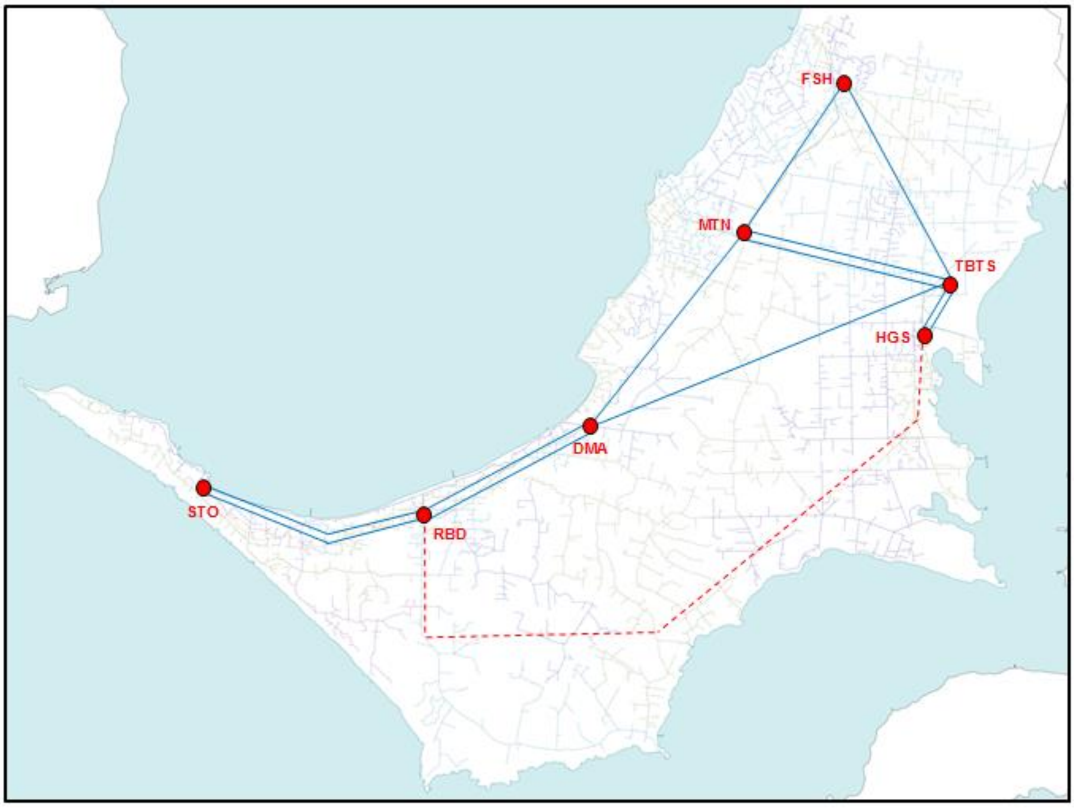
1 UE ATT105 - Assessment Lower Mornington Peninsula - May2016 - Public.

2 This includes overheads but excludes ongoing operating and maintenance costs.

2 Background

The lower Mornington Peninsula is supplied by three zone substations—Dromana (**DMA**), Rosebud (**RBD**) and Sorrento (**STO**). DMA is supplied by two 66kV sub-transmission lines from Tyabb Terminal Station (**TBTS**) and Mornington (**MTN**) zone substation. DMA supplies RBD and STO zone substations. This is illustrated in figure 1.

Figure 1 Existing distribution network in the Mornington Peninsula and potential future Rosebud to Hastings line



Source: United Energy

3 Identified need

There has been significant growth in residential electricity demand on the lower Mornington Peninsula. The number of permanent residents is increasing as holiday homes are being converted into permanent dwellings, residential developments and retirement villages. Further, the continued popularity as a holiday destination means the population rises from approximately 150,000 residents to more than 200,000 during the summer months. This is putting a strain on supply security.

In May 2016 we completed a RIT-D, which identified a need to invest to maintain supply security to the lower Mornington Peninsula. This was needed because:

- Expected unserved energy due to voltage collapse limitation—an unplanned outage on either of the incoming 66kV sub-transmission lines to DMA during summer maximum demand could cause voltage in the lower Mornington Peninsula to drop uncontrollably, leading to supply interruption to the entire region. Load must be reduced during system normal conditions for us to remain compliant with the system stability requirements in the National Electricity Rules.[3]
- Expected unserved energy due to insufficient thermal capacity in the sub-transmission network—five sub transmission lines in the region are forecast to have maximum demands that exceed their respective N-1 thermal ratings, and load transfer capability in the region is limited. Load must be reduced during post-contingent conditions to enable equipment to be operated within its thermal ratings.

The RIT-D found that a demand management program offered by GreenSync followed by installing a new $29.5 million ($2015) 66 kV line from Rosebud to Hastings by 2022 would provide net benefits of around $32 million. Therefore in 2018 we commenced demand management, which is contracted to continue through 2021.

3 National Electricity Rules, S5.1a.3(c).

4 Options analysis

This section outlines the options to maintain supply security over the 2021–2026 regulatory period.

4.1 Option one—do nothing

Option one is to undertake no investment (including demand management) in the lower Mornington Peninsula.

There has not been a material change in circumstances since the RIT-D was completed. The identified need, options considered and levels of current demand remain relevant.[4] It is not feasible to 'do nothing' because demand has already passed the point at which it is economic to maintain supply security as identified by the RIT-D.

4.2 Option two—capital solution

Option two is to install a new 66 kV line from Rosebud to Hastings by 2022 at a cost of $29.5 million ($2015) as identified in the RIT-D.

4.3 Option three—enhance demand management program

Option three is to enhance the demand management program and continue to defer investment of the 66 kV line from Rosebud to Hastings to the 2026–2030 regulatory period.

4.3.1 Forecast demand

We have updated the lower Mornington Peninsula demand forecast from when the RIT-D was undertaken. This forecast, outlined in appendix A, was completed by an independent demand forecaster—National Institute of Economic and Industry Research (**NIEIR**)—as part of our network demand forecasts.[5] In summary, the strong growth in actual demand has continued over the last few years, however, updated forecasts show a flattening of maximum demand until 2021/22. From this point onwards, demand growth returns to a similar rate as previously forecast, but from a lower starting base.

This demonstrates the benefit of the demand management program we implemented in the 2016–2020 regulatory period (which has allowed us to defer augmentation to a time where updated and flatter demand forecasts are available) and the potential to continue demand management over the 2021–2026 regulatory period. Table 2 outlines the demand management that would have been required under the 2015 demand forecasts undertaken for the RIT-D and the demand response now required to continue deferring augmentation.

Table 2 Demand management requirements (MVA)

Year	2018	2019	2020	2021	2022	2023	2024	2025
Required demand response—2015 demand forecast	11.5	12.2	13.1	13.1	17.1	19.7	25.0	N/A
Required demand response—updated demand forecast					13.1	13.5	17.7	21.8

Notes: 2018–2021 show demand response requirements under the existing contract.
Source: United Energy

4 Updated 2018 demand forecasts, however, show flatter demand over the next few years, which may mean demand management could continue.

5 UE MOD 9.07 - Maximum demand forecasts - Jan2020 - Public.

4.3.2 Viability of demand management

To determine the viability of demand management we compared the annualised cost of investing in a 66 kV line from Rosebud to Hastings to the cost of demand management, where the:

- annualised cost is the real weighted average cost of capital multiplied by the cost of the 66kV feeder plus an allowance for operating and maintenance costs
- demand management cost is the demand management unit rate (discussed below) multiplied by the excess demand shown in the bottom line of table 2.

The results are shown in table 3.

Table 3 Compare demand management cost and augmentation cost ($ 000, 2019)

Year	Annual cost of demand management	Annual cost of augmentation	Demand management economic?
2021/22	1,138	1,481	Yes
2022/23	1,173	1,481	Yes
2023/24	1,537	1,481	No
2024/25	1,893	1,481	No
2025/26	2,223	1,481	No

Source: United Energy

Demand management is the least cost option in 2021/22 and 2022/23, and not thereafter.

We believe we should aim to implement an enhanced demand management program for the 2021–2026 regulatory period given:

- demand management is within range of the annualised capital cost in the latter years, particularly when there is still uncertainty in the cost of the augmentation solution (easement costs, for example)
- demand management cost may reduce in future years
- the need for the industry to continue to pursue and grow demand management solutions
- the successful delivery of this demand management program to date.

However, we will cap demand management payments for this project to the avoided cost of the 66kV feeder to ensure our customers only pay efficient costs. That is, if during the 2021–2026 regulatory period demand management cannot be provided at this cost, we would undertake the capital solution in accordance with our 2016 RIT-D.

The alternative would be to seek funding of $29.5 million ($2015) for the capital solution during the 2021–2026 regulatory period.

4.3.3 Demand management unit costs

To forecast the cost of enhancing our demand management program, we have applied a unit rate based on actual demand management programs we have engaged in.[6] This unit rate has also been independently reviewed and compared to the demand management rates of other distributors by CutlerMerz. They 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.[7] This is outlined in detail in appendix B and summarised in table 4.

Table 4 Demand management unit rate ($ 000, 2018)

Demand management type	Program	Cost/MVA/year	Average	Weighting	Contribution to unit cost
Residential	Summer Saver	134	134	18%	24
Commercial, industrial	Rosebud to Hastings	68	74	82%	61
	MGE 12	81			
Total demand management unit cost					**85**

Source: United Energy

We have not based the demand management costs on the current Rosebud to Hastings demand management program alone because we are aware that GreenSync is incurring higher costs than the contracted payments it receives, and that these rates are not sustainable.[8]

GreenSync's current demand management program was based on predominantly commercial and industrial customers' participation. However, it could not find sufficient demand management from these customers. Subsequently, as a temporary measure GreenSync installed 11MW of diesel generators across five locations.

GreenSync (or another provider) will continue to incur higher demand management costs as it continues to lease the necessary land and diesel generators. GreenSync has indicated it intends to progressively replace the generators with a more long-term and environmental solution as it looks to consolidate and expand its portfolio across the Mornington Peninsula.[9]

Our demand management unit rate is a blended rate of actual commercial and industrial, and residential demand management programs. It is a conservative estimate because it includes the Rosebud to Hastings demand management costs which understates the actual cost.

6 This same rate has been used across United Energy HV feeder demand management programs.

7 UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public.

8 In 2018 GreenSync requested a renegotiation of the network support agreement with us to bring forward costs associated with delivery of the demand management programme to meet higher than expected upfront establishment costs, particularly relating to network connection costs of its generators. This successful renegotiation did not increase our overall cost of the programme.

9 A pipeline of potential customers able to provide demand response is being worked through by GreenSync and this is expected to see more customers participating in the programme as it becomes known throughout the community. The GreenSync roadmap also includes utilising battery capacity through its deX platform and retailer engagement as battery installations take off across the region.

4.4 Quantifying the necessary operating expenditure step change

A step change is required to our operating expenditure allowance (incremental to our 2019 base operating expenditures) to enhance the demand management program because:

- more demand management (from history) is required as shown in table 2
- the current demand management contract understates the actual cost of demand management as discussed above.
- due to GreenSync incurring unexpected costs for leasing and installing diesel generators, in 2018 GreenSync requested the demand management contract be revised such that the payments are front loaded to 2018. We accepted the change because the overall demand management costs and services remained broadly unchanged. However, we understand the contracted annual costs in our 2019 base year (and subsequent years of the contract) now understate the actual costs of providing demand management.

To calculate the operating expenditure step change, we have capped the demand management allowance being sought at the avoided capital expenditure cost. We have also subtracted the demand management costs included in our 2019 operating expenditure base year arising from the existing GreenSync contract. The required operating expenditure step change is outlined in table 5.

Table 5 Operating expenditure step change ($000, 2019)

Year	Annual cost of demand management	Base year demand management	Step change
2021/22	1,138	263	875
2022/23	1,173	263	910
2023/24	1,481	263	1,218
2024/25	1,481	263	1,218
2025/26	1,481	263	1,218
Total			**5,438**

Source: United Energy

5 Recommendation

Pursue the demand management option (option 3) and continue to defer $29.5 million ($2015) in capital expenditure out to the 2026–2030 regulatory period. This requires an operating step change above our 2019 base as shown in table 6.

For more information on the investment refer to the demand management lower Mornington Peninsula model.[10]

Table 6 Operating expenditure Step change ($ million, 2019)

Year	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Step change	0.9	0.9	1.2	1.2	1.2	5.4

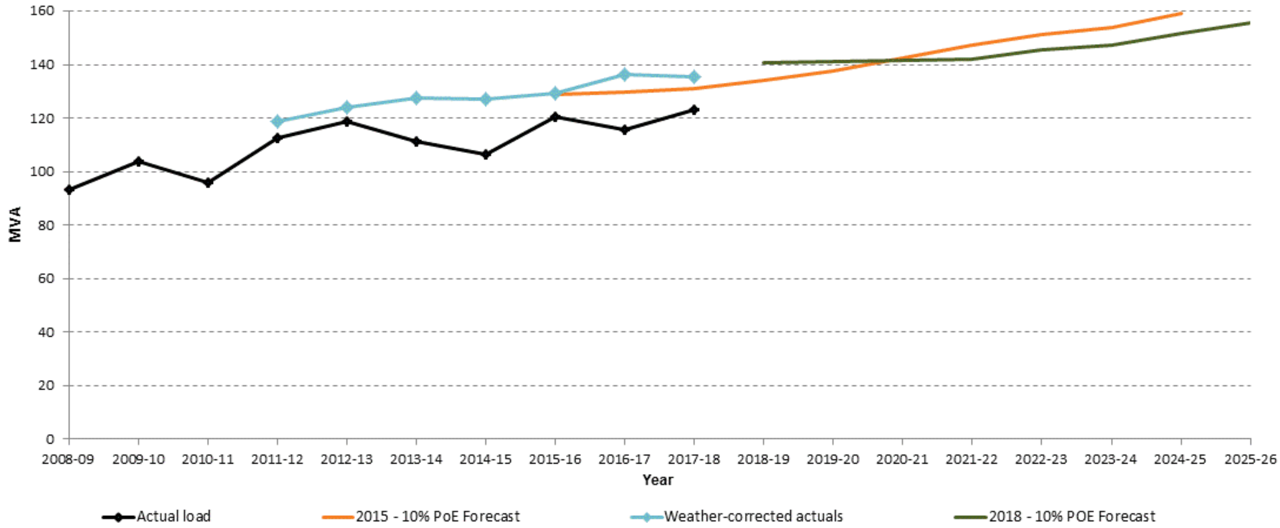
Source: United Energy

10 UE MOD 9.04 - Demand management Lower Mornington - Jan2020 - Public.

A Updated demand forecasts

Figure 2 shows an update of 'figure 5' from the Final Project Assessment Report for the Lower Mornington Peninsula Supply Area RIT-D which forecasts the lower Mornington Peninsula maximum demand.[11] This updated figure includes the latest actual demand and demand forecasts undertaken in 2018 (and the previous 2015 forecasts for comparison).

Figure 2 Updated forecast maximum demand



Source: United Energy

The strong growth in actual demand has continued over the last few years. In fact the growth in actual demand over the last two summers has been stronger than was originally forecast in 2015, as can be seen by comparing the weather corrected actual (light blue) and 2015—10% probability of exceedance (**POE**) forecast (orange) traces.

However, the 2018 10% POE forecast shows a flattening of maximum demand until 2021/22. This differs from the 2015 forecast under which demand continued increasing. Based on the 2018 forecast, maximum demand does not reach the previously forecast summer 2021/22 maximum until 2023/24. From this point onwards, demand growth returns to a similar level to the previous forecast. Flatter demand growth has allowed us to consider enhancing and continuing the demand management program.

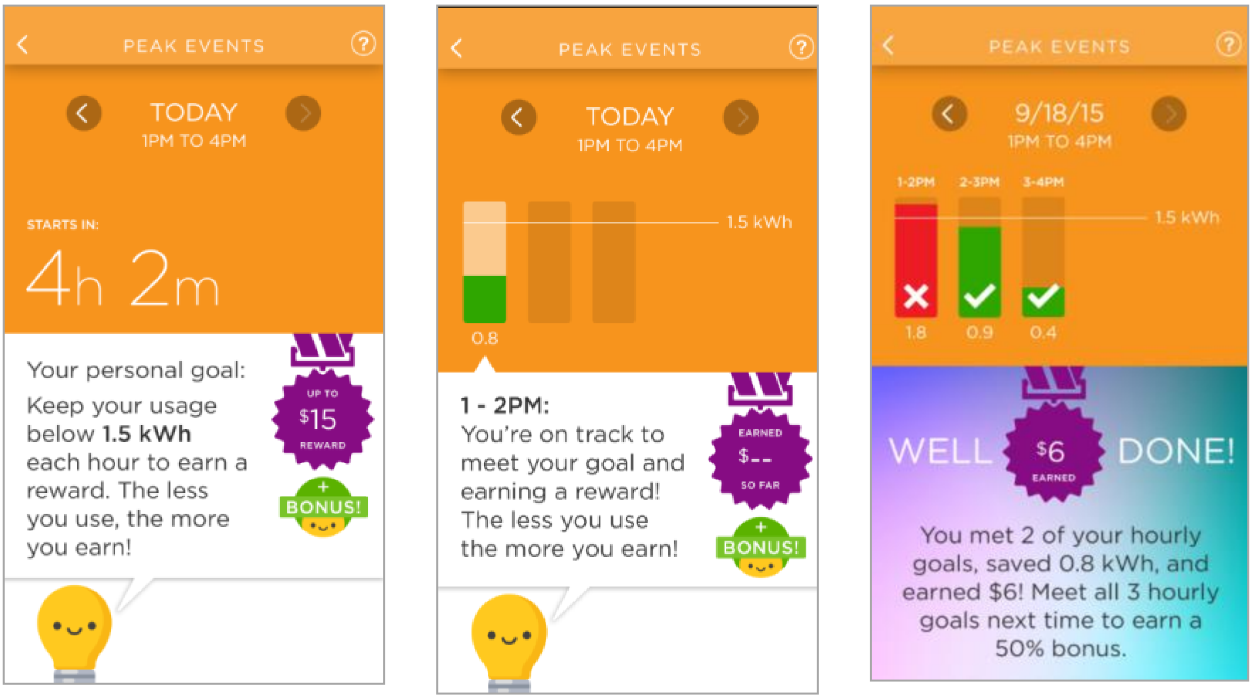
[11] UE ATT105 - Assessment Lower Mornington Peninsula - May2016 - Public

B Demand management unit costs

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

- lower Mornington Peninsula sub transmission line project deferral (discussed in this business case).
- MGE 12 distribution feeder deferral—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. We have signed up more than 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 demand reduction 1kW per customer. Figure 3 summarises the Summer Saver program.

Figure 3 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 7.

Table 7 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.