Mornington supply area

UE BUS 6.05

Regulatory proposal 2021–2026

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Contents

1 Overview

Mornington is one of the fast-growing regions in the Mornington Peninsula. With improved access following the establishment of the Peninsula Link in 2013, the popularity of the area has further increased, stimulating growth in both residential and commercial sectors.

This business case assesses options to support the growing population and maximum demand in the Mornington supply area. Our preferred option to address the identified need includes the following:

- staggered installation of two new feeders at the Mornington (**MTN**) zone substation
- install a third transformer at the MTN zone substation.

The forecast capital and operating expenditure requirements for the preferred option are outlined in table 1. These forecasts have been developed in calendar year terms, and converted to financial year terms in our consolidated expenditure modelling following changes to our reporting period (as required by the Victorian Government and the Australian Energy Regulator).

Table 1 Expenditure forecasts for preferred option ($ million, 2019)

Expenditure forecast	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capital expenditure	0.44	-	-	4.55	2.24	7.23
Operating expenditure	0.00	0.01	0.01	0.01	0.04	0.07
Total	**0.44**	**0.01**	**0.01**	**4.56**	**2.28**	**7.30**

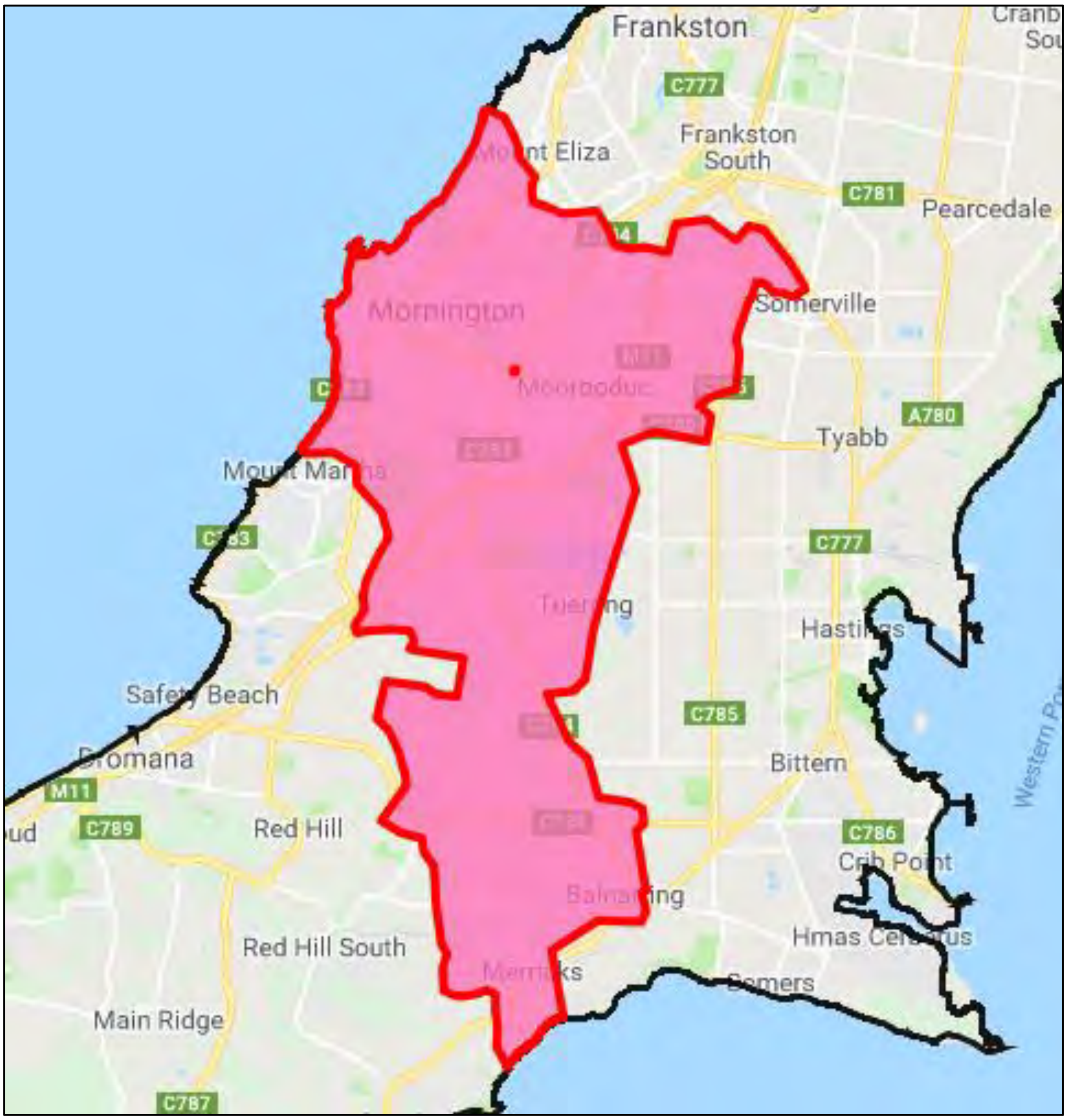
Source: United Energy
Note: Numbers may not add due to rounding

This project will also be subject to assessment as required under the regulatory investment test for distribution (**RIT-D**). As part of this approach, we have begun working with the community, retailers and non-network providers to actively seek demand-side options to defer part or all of the preferred network solution. To date, we have not received any formal proposals.

2 Background

MTN zone substation provides electricity supply to approximately 23,000 customers in Merricks, Merricks North, Balnarring, Tuerong, Moorooduc and Mornington (as shown in figure 1). These customers are predominantly residential, with a mix of light industrial and commercial establishments.

Figure 1 MTN supply area



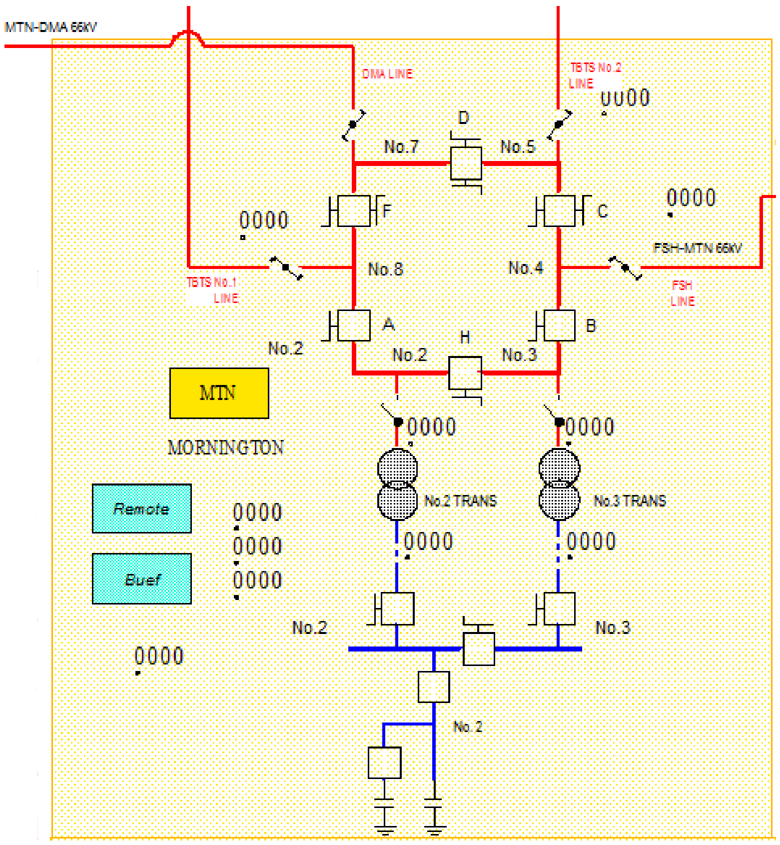
Source: United Energy

2.1 Existing network characteristics

2.1.1 Sub-transmission and zone substation

MTN zone substation was rebuilt in December 2012. It is a fully switched zone substation with two 66/22kV 20/33MVA transformers and an indoor 22kV switch room. MTN zone substation also has the flexibility of hosting a relocatable transformer in the event of a major transformer outage. A single line diagram of MTN is shown in figure 2.

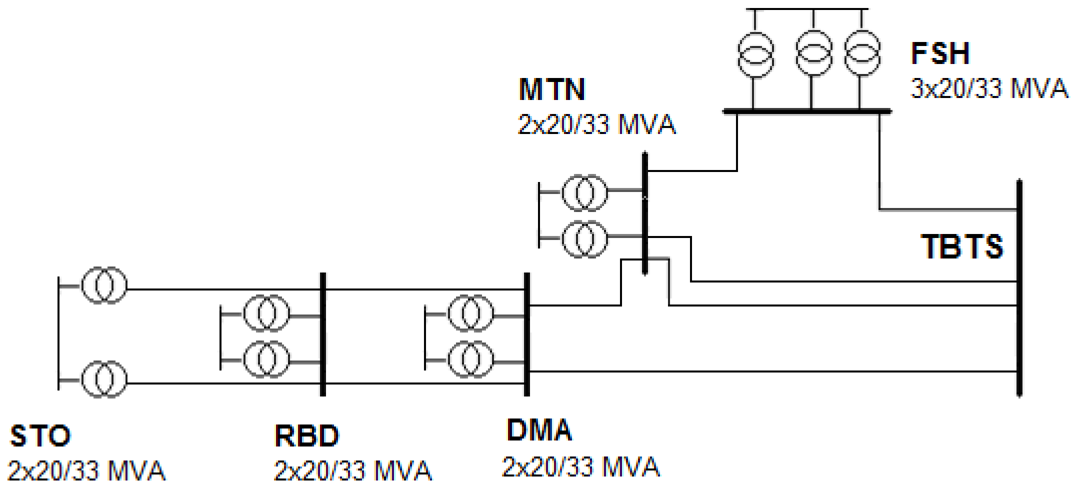
Figure 2 MTN single line diagram



Source: United Energy

As shown in figure 3, MTN zone substation is connected to the Tyabb Terminal Station (**TBTS**) through a meshed sub-transmission system with Dromana (**DMA**) and Frankston South (**FSH**) zone substations. Two more zone substations, Rosebud (**RBD**) and Sorrento (**STO**), are radially connected downstream of DMA.

Figure 3 Sub-transmission network around MTN



Source: United Energy

2.1.2 Distribution feeders

MTN zone substation has eight 22kV feeders that supply demand, and a 6MVAr station capacitor bank to provide reactive power support. There is one spare circuit breaker available at MTN to establish a future feeder to support the demand growth in the area.

2.2 Planning approach

We apply a probabilistic approach to planning our zone substation, sub-transmission and primary distribution feeder asset augmentations. This approach involves estimating the probability of an outage occurring within the peak loading season, and weighting the costs of such an occurrence by its probability to assess:

- the expected cost that will be incurred if no action is taken to address an emerging constraint, and therefore
- whether it is economic to augment the network capacity to reduce expected supply interruptions.

The quantity and value of energy at risk is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint. Probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under conditions of extreme loading. The probabilistic approach requires expenditure to be justified with reference to the expected benefits of lower unserved energy for customers.

3 Identified need

The identified need is to maintain a reliable supply of electricity to customers in the MTN supply area as the level of energy at risk on the existing infrastructure continues to grow over time. The level of energy at risk is discussed below.

3.1 Forecast demand

MTN is a summer critical zone substation. Growth in maximum demand is expected to increase in the coming years at an average annual compound growth rate of 1.4%.

The demand growth in the MTN supply area is primarily due to the following:

- staged development of residential estates, retirement villages and other residential sub-divisions
- staged development of light industrial areas
- large infill developments, such as apartments and health care facilities.

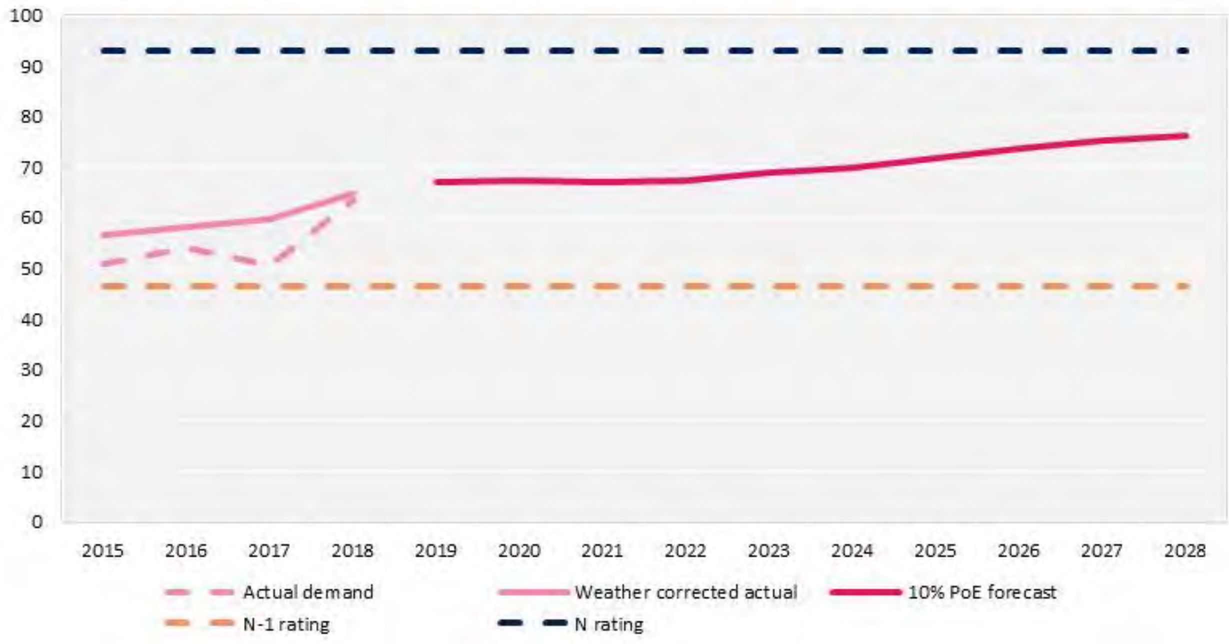
The drivers of electricity maximum demand growth in the MTN supply area are further discussed in appendix A. This appendix highlights the historical rapid growth in the area and amount of vacant land still available for future development.

3.1.1 Maximum demand and thermal capacity at MTN

Historical maximum demand and weather-corrected maximum demand at MTN zone substation have been above the station N-1 rating since 2013. As shown in figure 4, maximum demand is forecast to continue above this N-1 rating (under 10% probability of exceedance (**PoE**) weather conditions).[1]

[1] PoE refers to weather in any given summer exceeding the specified reference level (or the percentile) based on the last 50 years of historical weather data.

Figure 4 MTN zone substation maximum demand forecast at 10% probability of exceedance (MVA)



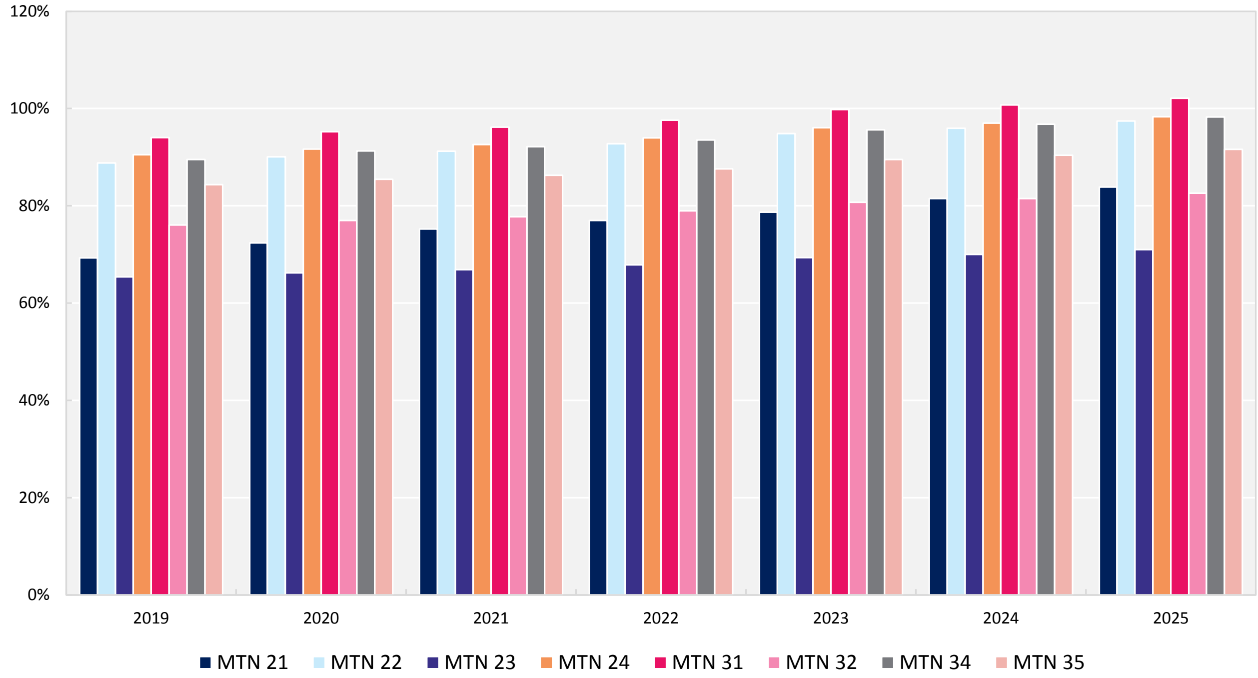
Source: United Energy

3.1.2 Feeder utilisation

As shown in figure 5, several MTN feeders are forecast to exceed (or become close to exceeding) their respective utilisation ratings in the near term. This limits the ability to manage supply during both system-normal conditions and during emergencies (i.e. loss of a feeder due to unplanned faults).

The MTN distribution network has also been reconfigured several times in the past to manage feeder utilisations. Further opportunities to optimise the feeder network without capital expenditure are minimal.

Figure 5 Feeder utilisation: ratio of maximum load to feeder rating (%)



Source: United Energy

3.2 Energy at risk

Consistent with our probabilistic planning approach, the quantity and value of energy at risk is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint.

3.2.1 Load transfer capacity

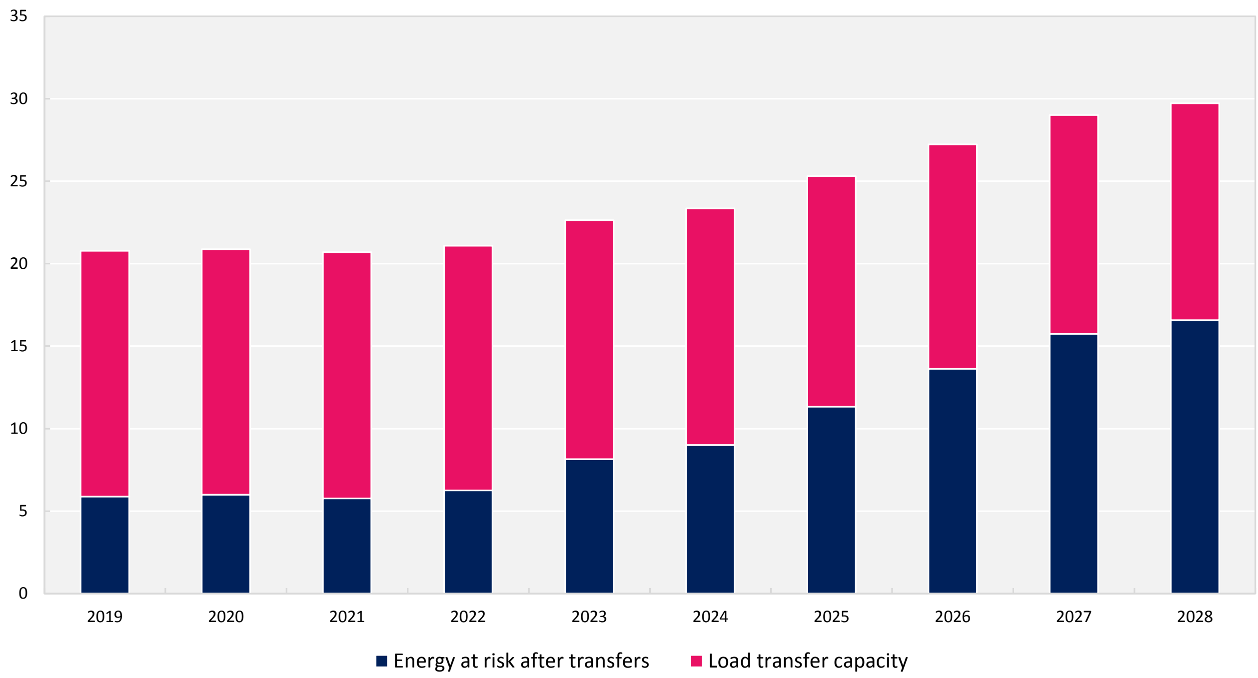
The large geographic area covered by MTN and adjacent zone substations means that many of the distribution feeders are long and rural in nature. This makes load transfers relatively harder than meshed, urban zone substations. Further, the topology of the surrounding network means several feeders from MTN zone substation have no tie points with adjacent zone substations.

The available load transfer capacity between MTN and surrounding zone substations is assessed to be 15MVA for the 2018–2019 summer (as shown in the attached business case model).[2] With forecast demand growth on the feeders in this area, the available load transfer capability is expected to reduce further. This will leave more customers exposed to the risk of supply interruptions for longer periods of time.

The expected load above N-1 after transfers following a major outage of one of the MTN transformers during peak demand conditions is shown in figure 6. After load transfers are established, a shortfall in capacity of approximately 17MVA is forecast in 2028 (or loss of supply for approximately 7,000 customers).

2 UE MOD 6.08 - MTN supply area - Jan2020 - Public.

Figure 6 Load above N-1 after transfers (MVA)



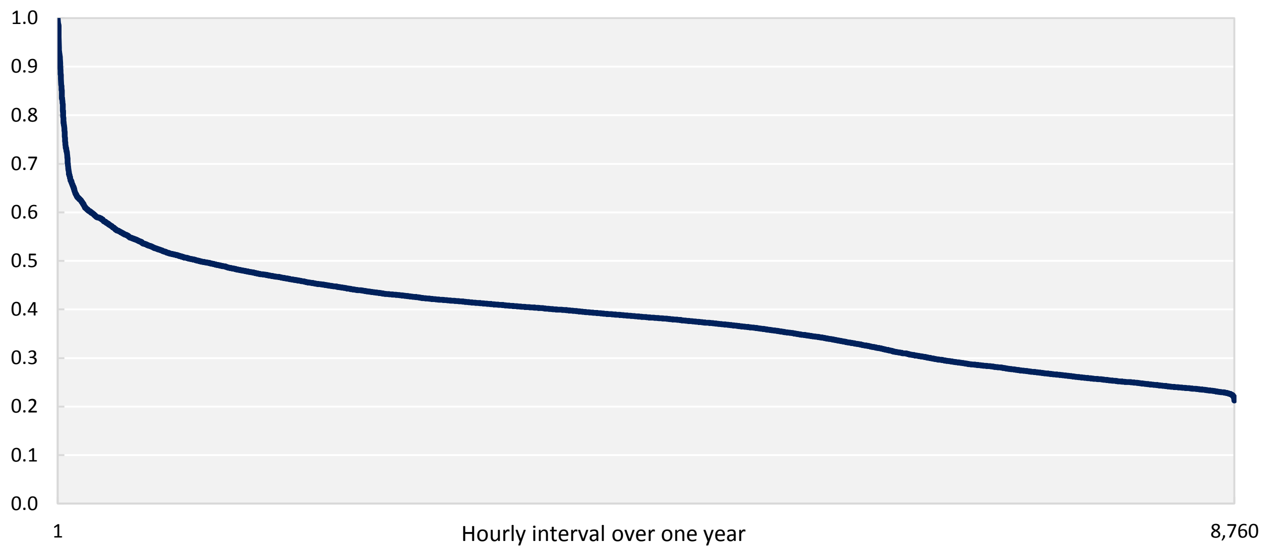
Source: United Energy

3.2.2 Energy at risk after load transfers

Our approach for calculating energy at risk is consistent with the probabilistic approach applied by the Australian Energy Market Operator (**AEMO**) to plan the Victorian shared transmission network.

A load-duration curve, based on historical load data, is used to determine the amount of energy at risk over the N and N-1 ratings each year. The load-duration curve for our MTN zone substation is shown in figure 97.

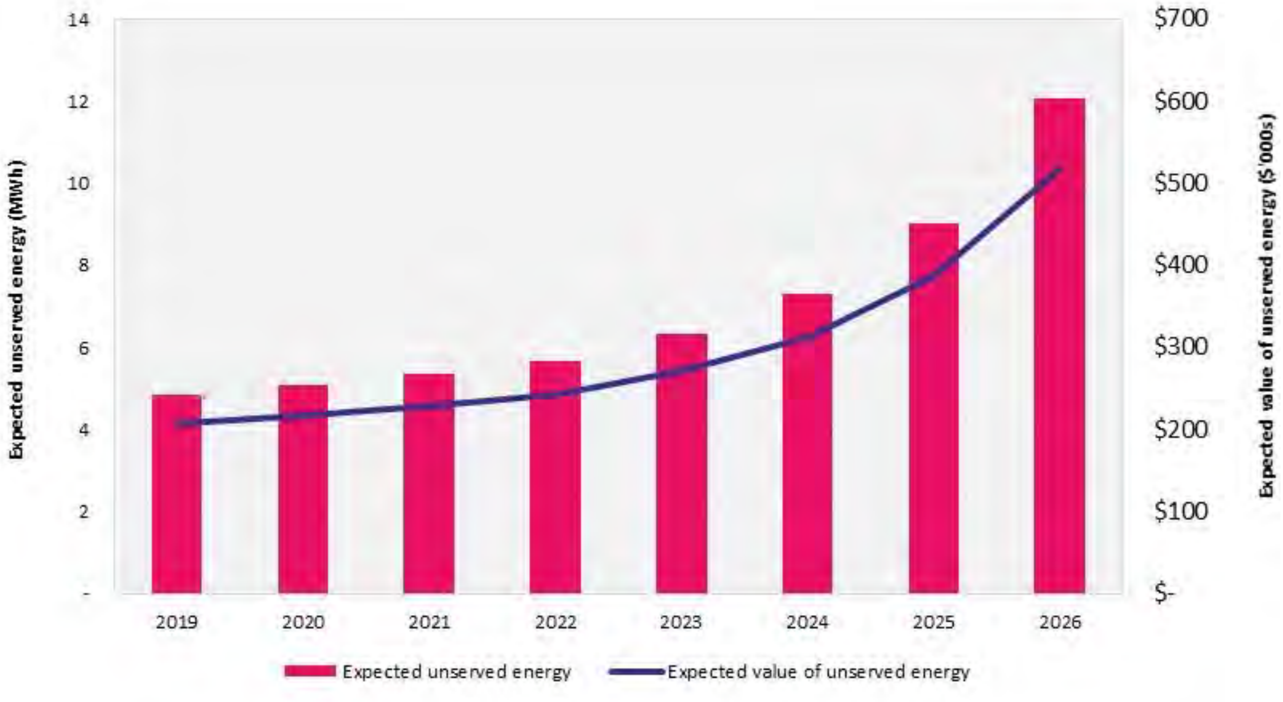
Figure 7 Load-duration curve (percentage of maximum demand)



Source: United Energy

The energy at risk is weighted by the probability of an outage to determine the expected unserved energy. The expected unserved energy is estimated using a 30:70 weighting of the 10% PoE and 50% PoE. The expected unserved energy and value of unserved energy (under a 'do-nothing' scenario) is shown in figure 8.

Figure 8 Do-nothing scenario: expected unserved energy (MWh) and value of unserved energy ($'000s)



Source: United Energy

Whilst the probability of a transformer failure is low, the energy at risk for such an event is high because customers will be affected for an extended period of time (e.g. until the transformer is repaired or replaced, a relocatable transformer is mobilised, or demand decreases to free up additional transfer capacity to adjacent zone substations).[3]

Further, there is a substantial amount of energy at risk in the distribution network as a result of the high utilisation of feeders. For an outage of a feeder during high demand, all the affected customers will be unable to be recovered as adjacent feeders do not have sufficient spare capacity.

Figure 8 demonstrates that the expected unserved energy levels for the supply area will increase significantly from current levels. This will result in deteriorating reliability of supply for the customers in this area, particularly during hot summer days. This business case demonstrates there is an identified need and an economic case to invest in the area to maintain reliability of supply at current levels.

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[3] MTN has been prepared to accommodate a relocatable transformer and we presently have two 66/22kV relocatable transformers (one at CDA and one at DSH). Given these relocatable transformers are in service and actually supplying customers (not spare transformers), the relocation is a complex process that needs coordination among several stakeholders. However, it is expected the relocatable transformer can be mobilised and connected at MTN within 5 days.

4 Options analysis

Several options were considered to address the identified need in the MTN supply area. These options address the identified need to varying extents, and as such, the preferred option is that which maximises the net economic benefits. This assessment of net economic benefits is presented relative to a 'do-nothing' scenario.

As shown in table 2, the preferred network solution is option one—install the MTN33 feeder, followed by a third transformer at MTN zone substation and another new feeder.

Table 2 Summary of net economic benefits ($ million, 2019)

	Option	Net economic benefits
Do-nothing	Maintain the status-quo	-
1	MTN33 feeder followed by MTN third transformer and second new feeder	5.08
2	MTN third transformer with two new feeders	5.03
3	Permanent load transfer to adjacent zone substations via feeder works	0.73
4	Permanent load transfer followed by MTN third transformer with one new feeder	4.96
5	Non-network solution to defer preferred network option	4.95
6	Power factor correction	N/A

Source: United Energy

The options considered are discussed in further detail below. The analysis supporting our assessment of alternative options, including relevant assumptions, is included in the attached model.[4]

4.1 Assessment of credible options

4.1.1 Do-nothing: maintain the status-quo

Maintaining the status quo—that is, continuing to supply customers serviced by the MTN zone substation without any intervention to manage energy at risk—will lead to significant supply interruptions for a single transformer or feeder outages. This option, therefore, fails to address the identified need (as set out in section 3).

4.1.2 Option one: MTN33 feeder followed by MTN third transformer and second new feeder

One option to address the identified need is to install a third transformer and two new feeders at the MTN zone substation. However, given the high feeder utilisation and availability of a spare feeder circuit breaker, establishing a new feeder prior to the installation of a third transformer and another feeder will substantially address the risk in the distribution network. This will defer the timing of a third transformer by one year.

There is sufficient space for a third transformer within the MTN zone substation switchyard, and the control room has provision for a third 22kV indoor switchboard.

The scope of works for this option includes the following:

[4] UE MOD 6.08 - MTN supply area - Jan2020 - Public

- establish new MTN33 feeder
- install new 66kV circuit breaker
- install new 20/33MVA 66/22kV transformer
- extend the 22kV indoor bus with:
  - one 22kV transformer circuit breaker
  - five 22kV feeder circuit breakers
  - one bus-tie circuit breaker
- install 66kV and 22kV connections, including connection to the existing neutral earthing resistor and the rapid earth fault current limiter
- upgrade existing protection and control schemes to accommodate the new configuration
- transfer three existing feeders to new 22kV bus #1 to spread feeders across each bus
- establish one new feeder and connect to bus #2 using a circuit breaker made available by transferring existing feeders to bus #1
- re-arrange existing feeders.

A breakdown of the costs for this option is available in our Reset Regulatory Information Notice.[5]

This option addresses the identified need, and maximises the net economic benefits to the market. Therefore, this is our preferred network option. A summary of the market benefits and costs of this option relative to the do-nothing option is summarised in table 3.

Table 3 Option one: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
MTN33 feeder followed by MTN third transformer second new feeder	-3.39	8.47	5.08

Source: United Energy

4.1.3 Option two: MTN third transformer with two new feeders

This option includes installing a third transformer at MTN zone substation, followed by two new feeders. This is similar to option one, however, the feeder works are completed together with the third transformer (rather than in two stages, before and after the transformer).

Relative to option one, installing the feeders together reduces the overall cost by approximately $0.1 million. It also brings forward the timing of the new transformer by one year. The scope of works for this option is otherwise the same as option one.

A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 4.

5 UE RIN001 - Workbook 1 - Forecast templates - Jan2020 - Public, template 2.3(a).

Table 4 Option two: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
MTN third transformer with two new feeders	-3.52	8.54	5.03

Source: United Energy

4.1.4 Option three: permanent load transfer to adjacent zone substations via feeder works

This option requires creating a new 22kV feeder from FSH along Frankston-Flinders Rd and Moorooduc Highway up to Humphries Road. This will reuse parts of our existing 22kV assets and approximately 2.8km of new build (of which half is expected to be underground due to congestion along the route).

FSH zone substation has spare feeder bays, but installation of a new circuit breaker will be required to enable the new feeder. Although the rating of the new feeder would be limited by the existing 22kV assets, it is sufficient to provide approximately 10MVA load transfer away from MTN zone substation.

The proposed new FSH feeder would supply part of the Mount Eliza area and assist in offloading highly utilised MTN22 and MTN35. However, it does not provide a direct solution to the remaining highly utilised feeders in the MTN supply area. Therefore, despite a lower capital cost, this option provides neither the least lifecycle cost solution to address the identified need, nor optimises the net economic benefits.

A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 5.

Table 5 Option three: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
Permanent load transfer to adjacent zone substations via feeder works	-1.08	1.81	0.73

Source: United Energy

4.1.5 Option four: permanent load transfer followed by MTN third transformer with one new feeder

This option builds on option three (i.e. a new 22kV feeder from FSH to permanently transfer 10MVA of load), however, it also includes the subsequent installation of a third transformer and one new feeder at MTN zone substation. The proposed new feeder will address the high feeder utilisation issues of MTN22 and MTN35.

This option will defer the timing of a third transformer by one year compared to option two, but does not provide a direct solution to the remaining highly utilised feeders in the MTN supply area. The estimated deferral benefit is also less than the cost of this option, and therefore, this option is not the least cost solution to address the identified need.

A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 6.

Table 6 Option four: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
Permanent load transfer followed by MTN third transformer with one new feeders	-3.54	8.49	4.96

Source: United Energy

4.1.6 Option five: non-network solution to defer preferred network option

This option considers the ability of a non-network solution to defer the preferred network option. For this assessment, we have estimated the cost of a non-network solution that would result in the energy at risk remaining at the same level as that forecast in the year immediately prior to the commissioning date of the preferred solution.

We have based the cost of a non-network solution on a benchmark rate of $87,000 per MW per annum. This rate is based on our recently implemented non-network solutions, and is supported by comparative analysis of other distributors experience provided by CutlerMerz.[6]

Assuming a new 22kV feeder will be implemented in 2021 (as per the preferred network option), the estimated non-network support requirements are summarised in table 7. For example, a 2.3MW non-network solution would bring the station load at risk back to the previous year's level and defer by one year the need for the balance of the option (i.e. a third transformer and one new feeder). The magnitude of the non-network support required to maintain this energy at risk level increases over time.

Table 7 Non-network support requirements (MW)

Year	2024	2025	2026	2027	2028
Demand at risk after load transfers	9.0	11.3	13.6	15.7	16.6
Non-network support	-	-	2.3	4.4	5.2

Source: United Energy

Based on the above, the full cost of a demand management solution is equal to the required network support multiplied by the benchmark rate, plus the annual costs of any residual unserved energy. In this case the net economic benefits of the demand management option are not as great as the preferred option, due in part to the lower residual unserved energy in the preferred option.

A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 8.

Table 8 Option five: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
Non-network solution to defer preferred network option	-3.29	8.24	4.95

Source: United Energy

This analysis shows that the non-network solution fails to economically defer the project. Irrespective of this high-level assessment, this project will be subject to assessment as required under the RIT-D. We will initiate consultation well before the economic timing of the preferred network option to maximise the chance of a viable non-network solution being identified.

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6 Attachment UE ATT102 - CulterMerz - Review of demand management - Feb2019 - Public, CutlerMerz, Review of demand management unit rates, February 2019.

4.1.7 Option six: power factor correction

Installing power factor correction equipment may be used to reduce reactive power, and as such, can sometimes be a cheaper alternative to defer augmentation. However, the operating power factor at MTN is close to unity during peak load, and as such, there is no requirement for any further reactive power compensation.

We expect the operating power factor will deteriorate slightly over time, and we will continue our practice of correcting the power factor at feeder levels to the extent it is technically and economically viable. Even with the expected deterioration of power factor over time, this option is only expected to provide marginal benefits. Therefore, the economics of this option have not been explored further.

4.2 Sensitivity analysis

A detailed sensitivity assessment was performed to assess the impact on the ranking of the options from varying the demand forecast, assumed discount rates, and the capital and operating expenditure forecasts. Two opposing scenarios were applied (equal to ±4% for demand forecasts, and ±10% for other variables), reflecting best and worst-case scenarios.[7]

Under the worst-case scenario, the ranking of the preferred network option (option one) remains the same. This changes under the best-case scenario, where the MTN third transformer with two new feeders (option two) results in higher net economic benefits.

Given the staged approach already envisaged under the preferred network option, this will allow alterations to the timing of a third transformer depending on the changes in demand growth.

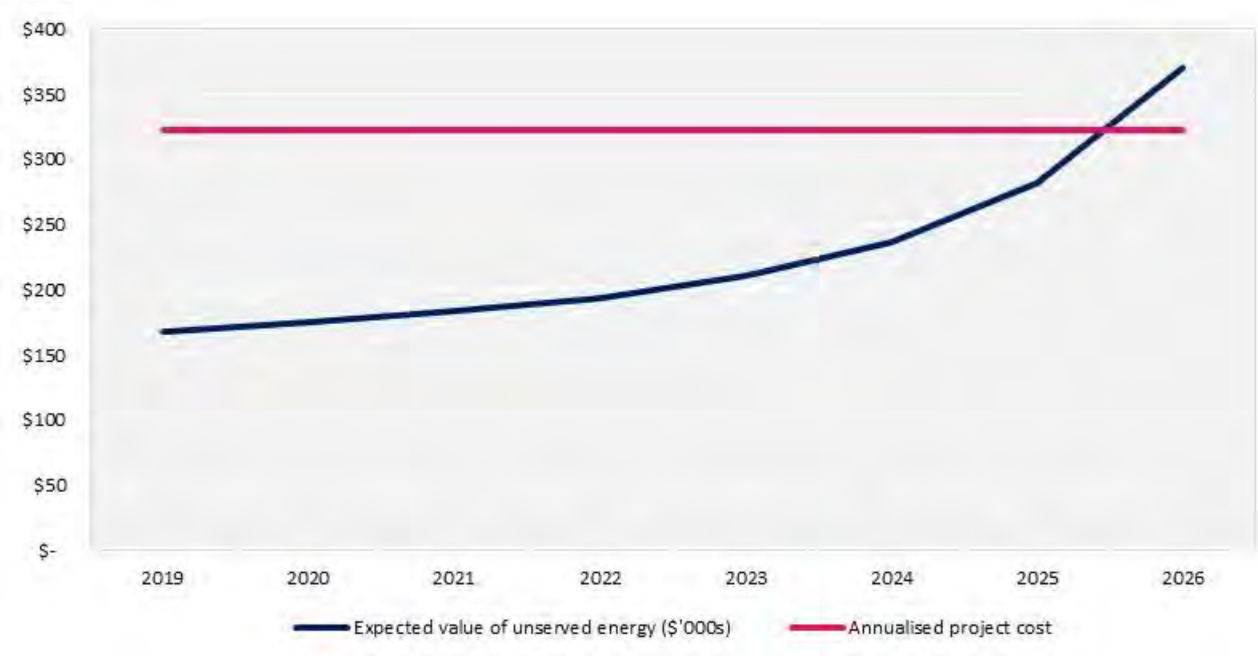
7 The sensitivity variance for demand forecasts (±4%) is consistent with the difference in growth between NIEIR's base, high and low forecast scenarios.

5 Recommendation

The preferred network option, as set out in section 4, is to install the new MTN33 feeder, followed by a third transformer at MTN zone substation and another new feeder. The required changes to the MTN zone substation and distribution feeder network are shown in appendix B.

A detailed economic assessment was performed to evaluate the optimum timing of the preferred network option. As shown in figure 9, the net market benefits of the preferred option, post the installation of MTN 33 feeder, exceeds the annualised costs of the third transformer and second feeder in 2026. This demonstrates that the optimal timing for commissioning the third transformer and second feeder is 2025.

Figure 9 Timing of preferred option ($'000s, 2019)



Source: United Energy

The forecast capital and operating expenditure requirements for the 2021–2026 regulatory control period are outlined in table 9. These forecasts have been developed in calendar year terms, and converted to financial year terms in our consolidated expenditure modelling following changes to our reporting period (as required by the Victorian Government and the Australian Energy Regulator).

Table 9 Expenditure forecasts for preferred option ($ million, 2019)

Expenditure forecast	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capital expenditure	0.44	-	-	4.55	2.24	7.23
Operating expenditure	0.00	0.01	0.01	0.01	0.04	0.07
Total	**0.44**	**0.01**	**0.01**	**4.56**	**2.28**	**7.30**

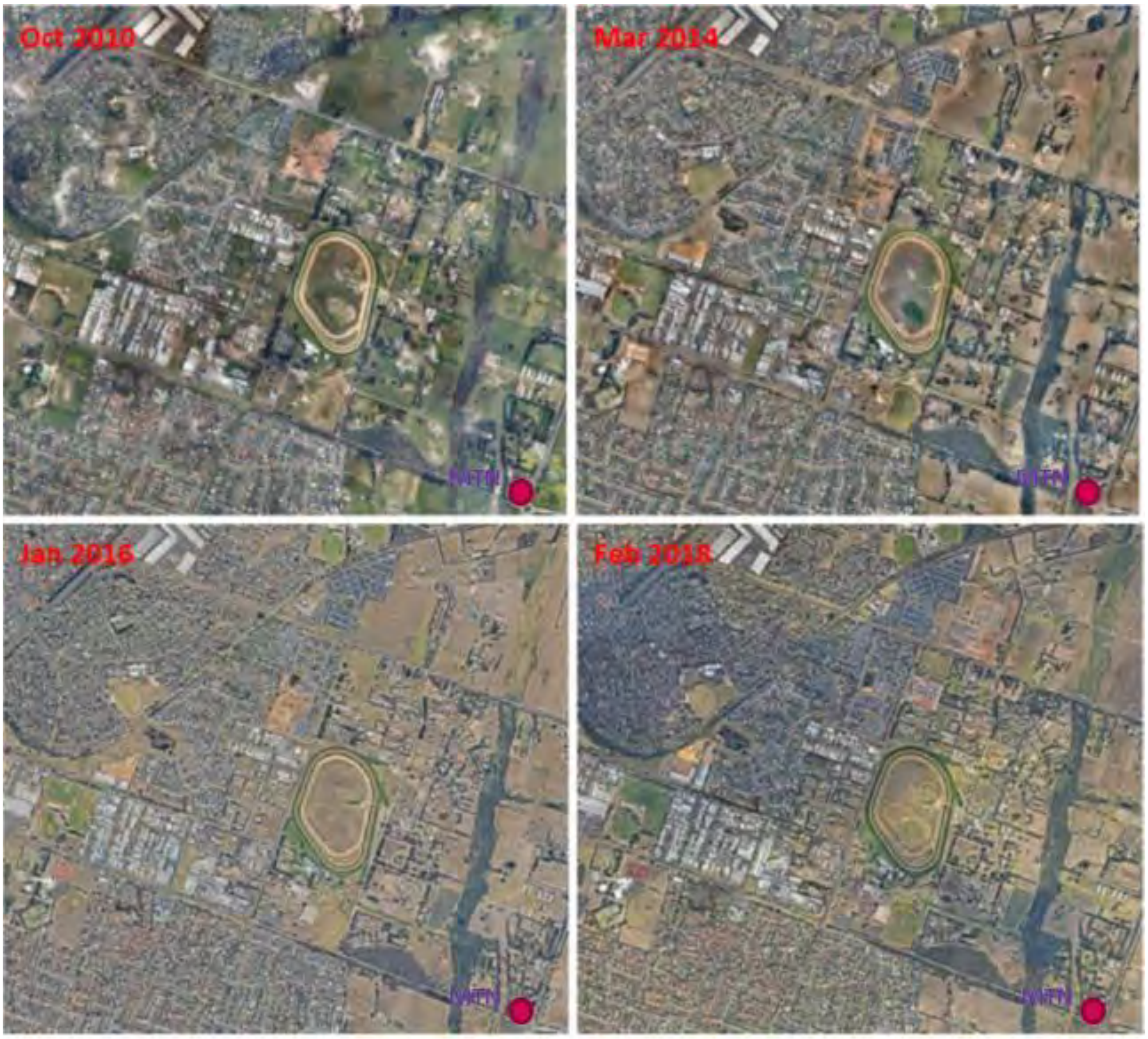
Source: United Energy

A MTN area demand growth

Substantial amounts of residential development including retirement villages and age-care facilities have taken place in the MTN supply area over the past years, especially around the Mornington Racecourse. These growth activities are expected to continue given the substantial amount of vacant land available for development.

The steady growth in the area from 2010 is shown in figure 10.

Figure 10 Growth in the MTN supply area



Source: United Energy

Several of the large industrial, commercial and residential developments currently happening in the MTN supply area are also shown below. The combined installed substation capacity at these sites is approximately 6MVA. Given the nature of those developments, the new load at those sites will gradually pick up over time when the occupants move in.

Figure 11 Large industrial, commercial and residential developments

Elite Way and Bayport Court Industrial Development

827 Nepean Hwy Nursing Home Development

33 Milgate drive Industrial Development

16-20 Main St Residential apartments

141-173 Bungower Rd URD

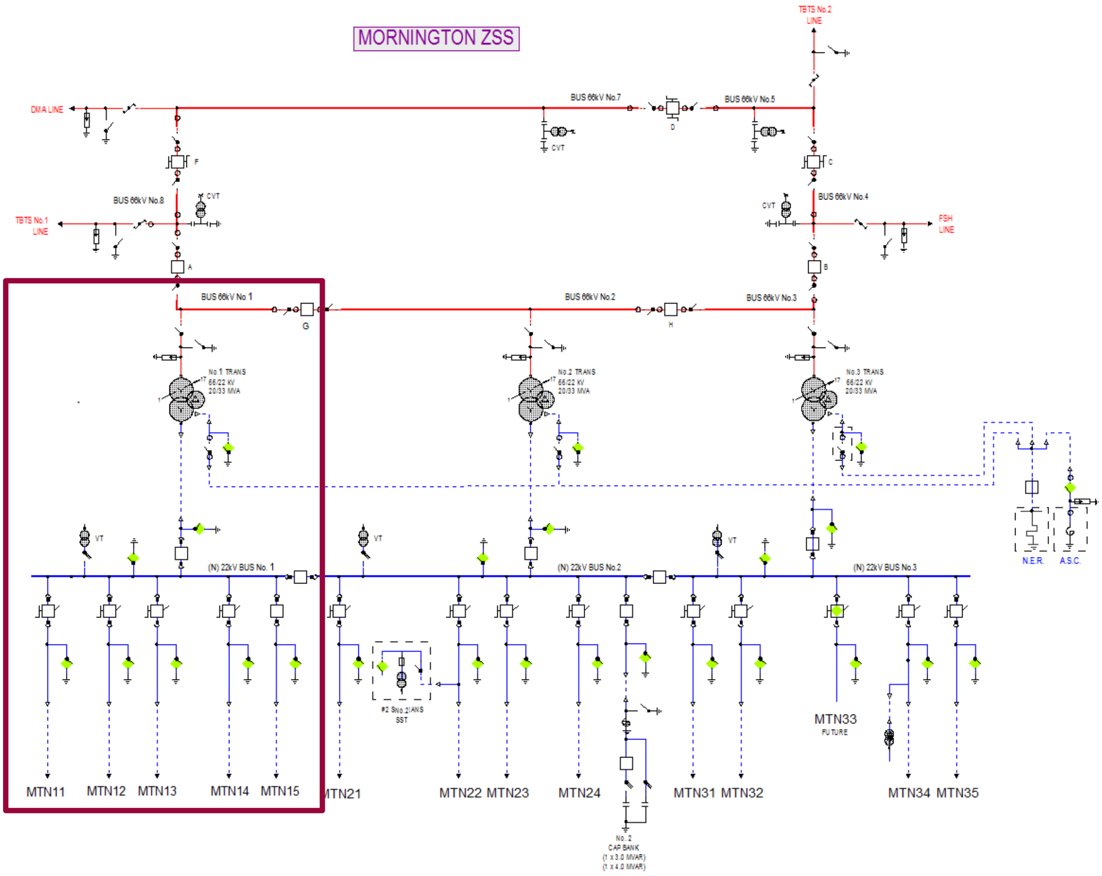
428 Racecourse Rd Retirement Village

988 Nepean Hwy Commercial Development

Source: United Energy

B Design of preferred network option

Figure 12 Proposed MTN zone substation arrangement

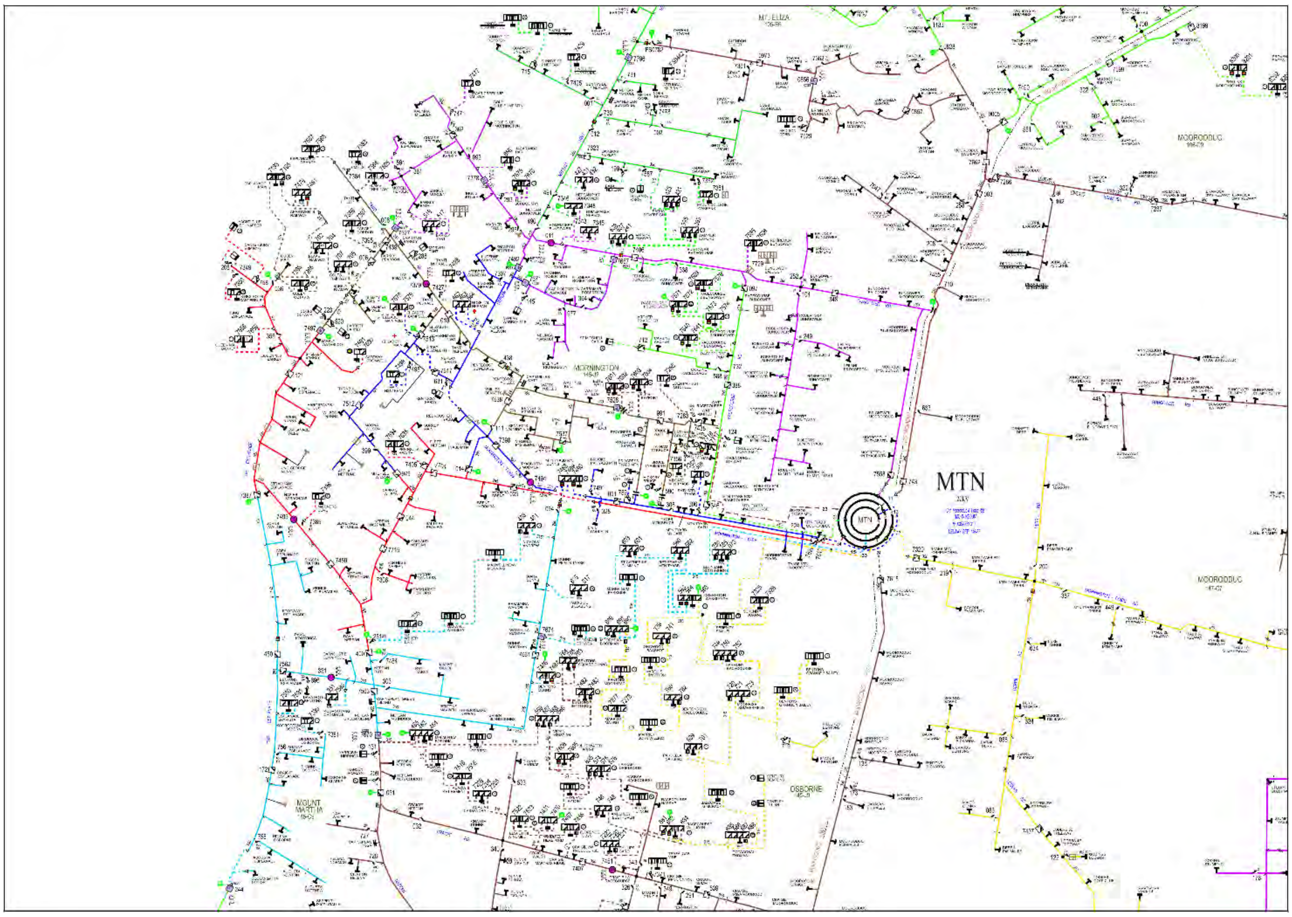


Source: United Energy

Figure 13 Proposed location for MTN third transformer

Source: United Energy

Figure 14 Proposed MTN distribution network after the project



Source: United Energy