Doncaster supply area

UE BUS 6.02

Regulatory proposal 2021–2026

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1 Overview

Doncaster (**DC**) zone substation was commissioned in the early 1960s to provide capacity to the Box Hill North, Doncaster, Doncaster East and Templestowe areas. This area has developed over time into a flourishing commercial and residential precinct, most notably supplying the Box Hill and Epworth Hospitals, Box Hill Institute and parts of the Doncaster Hill and Box Hill Central precincts.

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

- commission a new feeder from the neighbouring Box Hill (**BH**) zone substation and reconfigure the distribution network before December 2020
- install a fourth DC transformer with two new feeders before December 2024.

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 years 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	-	-	4.13	2.04	-	6.17
Operating expenditure	0.01	0.01	0.01	0.04	0.07	0.15
Total	**0.01**	**0.01**	**4.14**	**2.08**	**0.07**	**6.32**

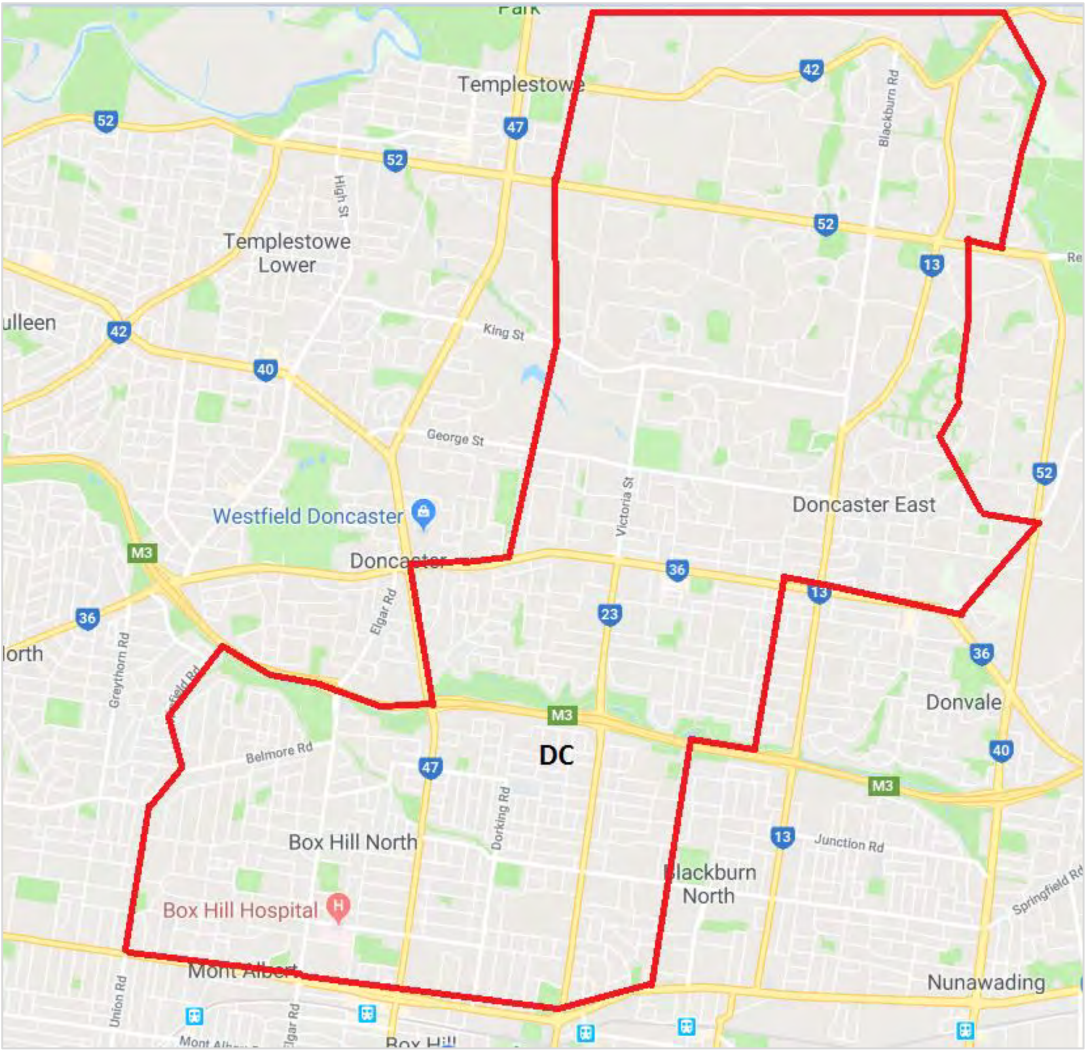
Source: United Energy
Note: Numbers may not add due to rounding

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 out demand-side options to defer part or all of the preferred network solution. To date, we have not received any formal proposals.

2 Background

Our DC zone substation supplies electricity to approximately 30,500 customers in Box Hill North, Doncaster East and Templestowe (as shown in figure 1). These customers are predominantly residential, with a mix of small to large commercial establishments.

Figure 1 DC supply area



Source: United Energy

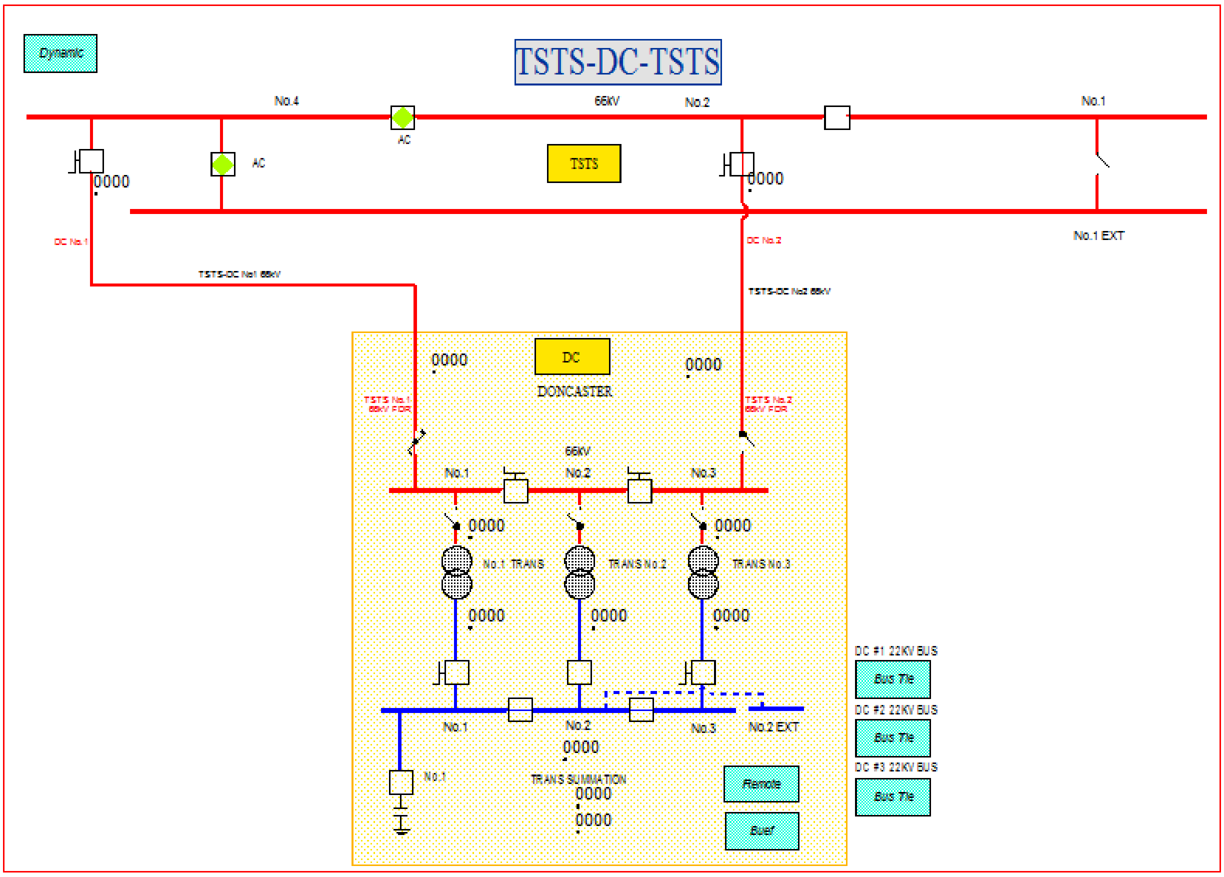
2.1 Existing network characteristics

2.1.1 Sub-transmission and zone substation

DC zone substation was established in the early 1960s. It consists of two 27MVA and one 30MVA 66/22kV transformers.

As shown in figure 2, DC substation is connected to the Templestowe Terminal Station (**TSTS**), forming the TSTS-DC-TSTS sub-transmission loop. There are no 66kV sub-transmission line circuit breakers at DC. This means that a fault on one of the sub-transmission lines (which is predominantly an overhead network) will lead to an outage of one of the 66/22kV transformer until the transformer is manually switched into service by the field crew.

Figure 2 DC sub-transmission network



Source: United Energy

2.1.2 Distribution feeders

DC zone substation has 10 distribution feeders that supply customers from Box Hill North to Templestowe. Due to the relatively vast service area, most of the feeders are long overhead lines by urban standards. Consequently, they are more exposed to faults from external influences such as weather.

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 efficient supply of electricity to customers in the DC supply area as the level of energy at risk continues to grow and our existing assets deteriorate over time. The level of energy at risk and the condition of our existing assets are discussed below.

3.1 Forecast demand

DC is a summer critical zone substation. Growth in maximum demand is expected to increase in the coming years at an average annual rate of 1.3%.

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

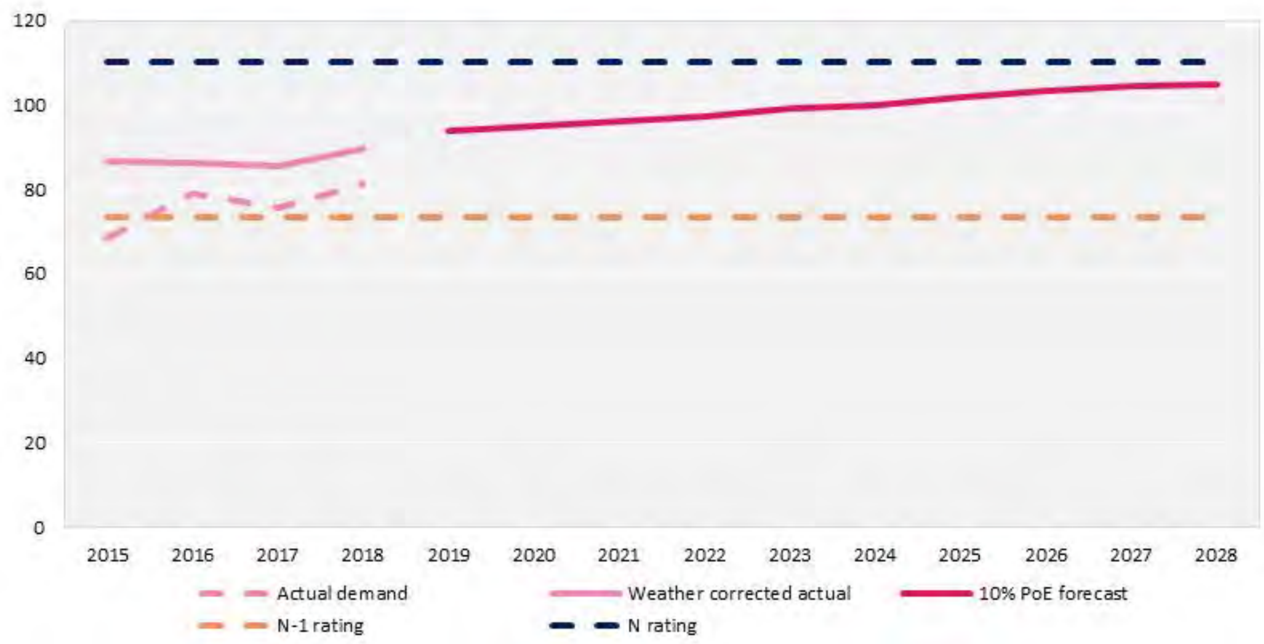
- the expansion of Epworth Hospital in Box Hill (+1.3MVA in 2019)
- increase in occupancy at the already built skyscrapers
- further high-density apartments and skyscrapers in the Box Hill Central and Doncaster Hill precincts
- further conversion of low-density dwelling to multi-story high density apartments and townhouses.

The drivers of electricity maximum demand growth in the DC supply area are further discussed in appendix A. This appendix highlights before and after images of the urban landscape at four key sites, as well as the extent of large planning applications occurring in the DC supply area.

3.1.1 Zone substation maximum demand

Historical maximum demand at DC has been above its N-1 summer cyclic rating since summer 2016. On a weather-corrected basis, DC zone substation has been operating above its N-1 summer cyclic rating since 2013. As shown in figure 3, maximum demand is forecast to continue growing above this N-1 rating.

Figure 3 DC zone substation maximum demand forecast at 10% probability of exceedance (MVA)

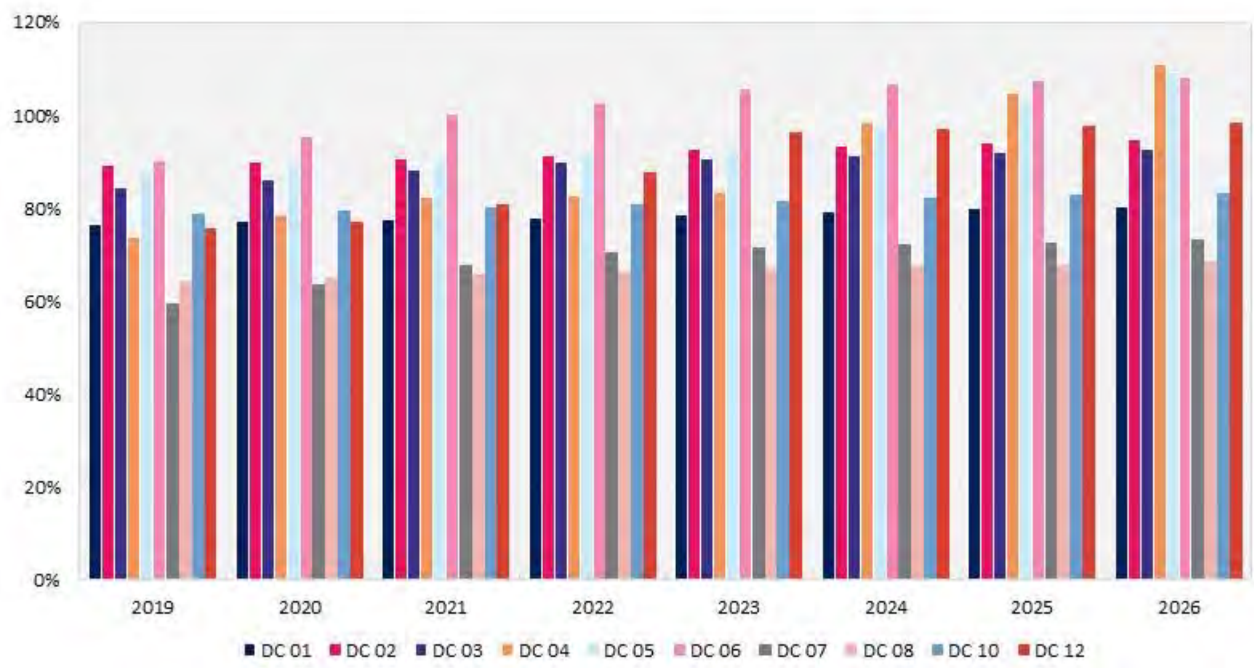


Source: United Energy

3.1.2 Feeder utilisation

As shown in figure 4, several DC 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).

Figure 4 Feeder utilisation: ratio of maximum load to feeder rating (%)



Source: United Energy

3.2 Transformer condition

All the transformers at DC zone substation are over 50 years of age. Two of the three transformers are in poor condition and have been assessed as being very close to end-of-life. Both of these transformers were constructed under the same design standards which means both the units are of the same make, age and possess identical characteristics. This presents an increasing common-mode failure risk at DC.

As the condition of these transformers deteriorate further, the energy at risk due to one or multiple transformer failures will become even more significant.

3.3 Energy at risk

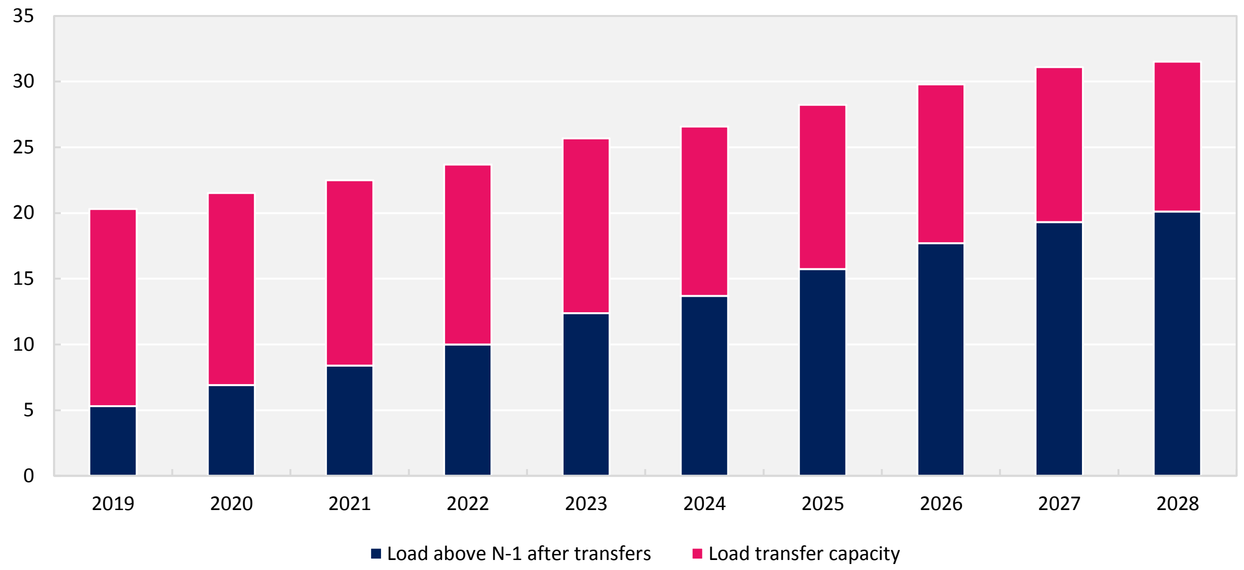
Consistent with our probabilistic planning approach, the quantity and value of energy at risk is a critical parameter in assessing a prospective network investment or other action in response to an emerging constraint.

3.3.1 Load transfer capacity

The available load transfer capacity between DC and surrounding zone substations is assessed to be 9.0MVA during the 2018–2019 summer. 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 DC transformers during peak demand conditions is shown in figure 5. Available load transfers are shown in the attached business case model.[1] After load transfers are established, a shortfall in capacity of approximately 20MVA is forecast in 2028 (or loss of supply for approximately 8,000 customers).

Figure 5 Load above N-1 after transfers (MVA)



Source: United Energy

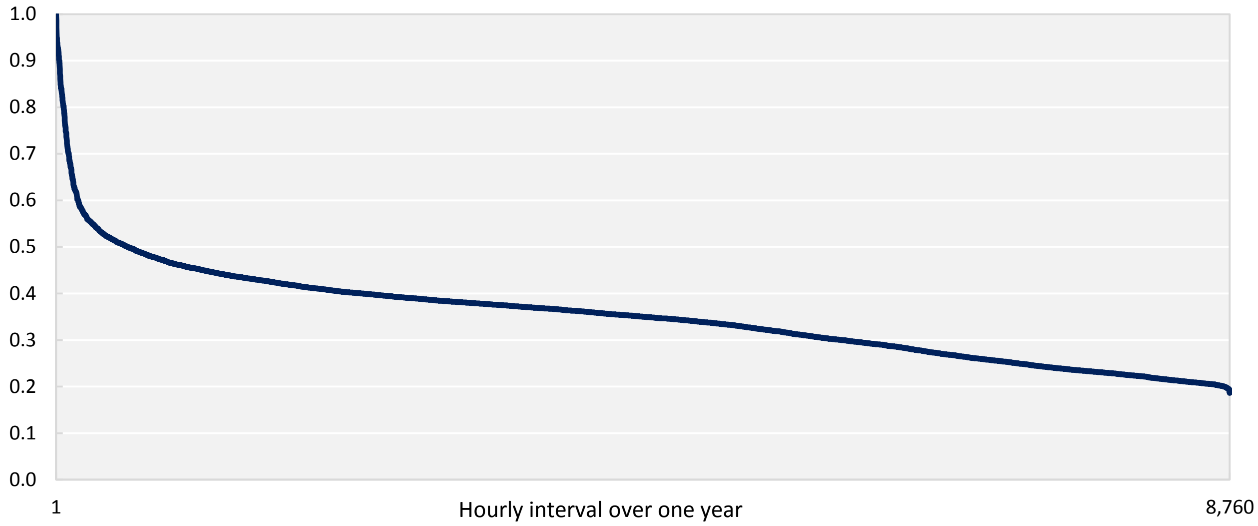
3.3.2 Energy at risk after load transfers

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 DC zone substation is shown in figure 6.

1 UE MOD 6.04 - DC supply area - Jan2020 - Public

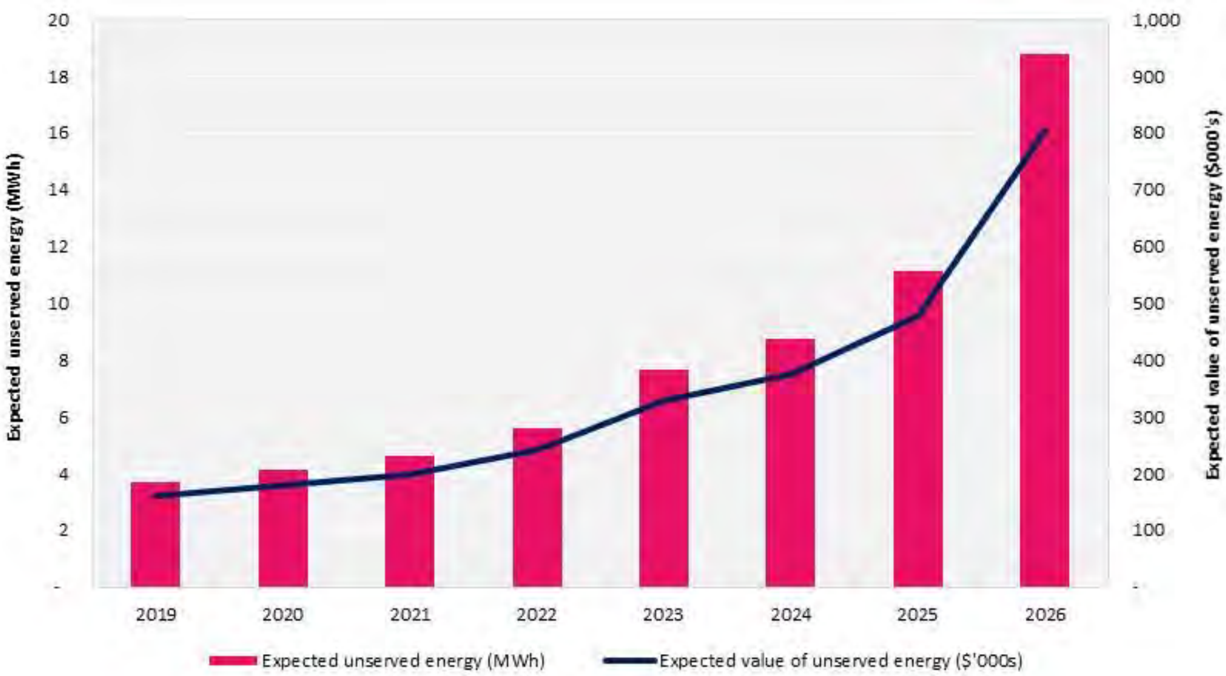
Figure 6 Load-duration curve (percentage of maximum demand)



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 7.

Figure 7 Do-nothing scenario: expected unserved energy (MWh) and value of unserved energy ($'000s)



Source: United Energy

Figure 7 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.

4 Options analysis

Several options were considered to address the identified need in the DC 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 solution is option one—install a new BH feeder, followed by two new feeders and a fourth transformer at DC zone substation.

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

	Option	Net economic benefits
Do-nothing	Maintain the status-quo	-
1	New BH feeder, followed by a fourth transformer and additional two feeders at DC	14.18
2	Fourth transformer and three new feeders at DC	14.01
3	New BH feeder, followed by transformer replacement and feeder works at DC	13.78
4	New BH feeder, followed by non-network solution to defer preferred network option	14.10
5	New TSE zone substation	N/A
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.[2]

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 DC zone substation without any intervention to manage energy at risk—will lead to significant supply interruptions for a single transformer outage. This option, therefore, fails to address the identified need (set out in section 3).

4.1.2 Option one: new BH feeder, followed by fourth transformer and additional two feeders at DC

This option comprises two separate stages. By December 2020, a new feeder from the neighbouring BH zone substation is required, including subsequent network reconfiguration works. This will allow some demand to be permanently transferred away from DC06, and defer the need for a new transformer at DC until 2024.

A fourth transformer and two new feeders will then be required at the DC zone substation by December 2024 to support expected demand. The scope of works includes the following:

- establishing a new #4 66kV bus
- installing a new 3-4 66kV bus tie circuit breaker

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- cutting in the TSTS-DC #1 line to the new #4 66kV bus
- demolishing the old control building to allow the installation of the fourth transformer
- relocating the secondary panels from the old control building to the new control building
- installing a new 20/33MVA 66/22kV transformer
- installing a new 22kV switchboard in the new control building
- installing a new station service transformer
- installing a 22kV auto-close scheme to manage fault levels
- establishing two new feeders, including the rearrangement of existing feeders to provide capacity for forecast growth in the Doncaster Hill and Box Hill Central precincts.

A breakdown of the costs for this option is available in our Reset Regulatory Information Notice.[3]

This option addresses the identified augmentation and replacement drivers, and has a lower total lifecycle cost than other credible options. A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 3.

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

Option	NPV costs	NPV benefits	Net economic benefits
New BH feeder, followed by fourth transformer and additional two feeders at DC	-3.59	17.77	14.18

Source: United Energy
Note: The cost of the BH feeder works are included in the above analysis, but are not included in our expenditure forecasts for the 2021–2026 regulatory period (as these works will be incurred in the 2016–2020 regulatory control period).

4.1.3 Option two: fourth transformer and three new feeders at DC

Under this option, a fourth DC transformer and three new feeders are established before December 2023. The scope of this option is similar to option one, except that a new feeder from DC (instead of BH) is established to alleviate the forecast overload on DC04.

This option addresses the identified augmentation and replacement drivers, but has a higher total lifecycle cost than the preferred option. A summary of the market benefits and costs of this option relative to the do-nothing option is shown in table 4.

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

Option	NPV costs	NPV benefits	Net economic benefits
Fourth transformer and three new feeders at DC	-3.71	17.72	14.01

Source: United Energy

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

4.1.4 Option three: new BH feeder, followed by transformer replacement and feeder works at DC

As per option one, this option includes a new feeder from the neighbouring BH zone substation to transfer demand away from DC06. The following additional works are then required:

- replace one DC transformer before December 2025
- commission a new DC feeder to alleviate capacity constraints on DC04 before December 2025.

Although this option addresses most of the replacement drivers and feeder constraints, it does not address the capacity constraint at DC (as the N-1 rating at the station is not increased) and subsequently a fourth transformer and switchboard will still be required in 2033. Moreover, as there are no spare circuit breakers at DC, the new DC feeder will need to be connected using a jumbo connection. Given most of the DC feeders are moderately or highly loaded, a loss of this jumbo feeder can lead to supply interruptions for customers until the demand subsides.

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
New BH feeder, followed by transformer replacement and feeder works at DC	-2.98	16.76	13.78

Source: United Energy

4.1.5 Option four: new BH feeder, followed by 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.[4]

The estimated non-network support requirements to defer the fourth transformer and two feeders at DC in the preferred network option are summarised in table 6. For example, a 1.9MW 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 fourth transformer and two feeders). The magnitude of the required non-network support required to maintain this energy at risk level increases over time.

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

Table 6 Non-network support requirements (MW)

Year	2023	2024	2025	2026	2027
Demand at risk after load transfers	17.7	18.8	20.7	22.4	23.9
Non-network support	-	-	1.9	3.6	5.1

Source: United Energy

Based on the above, the full costs 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 7.

Table 7 Option four: benefits assessment summary ($million, 2019)

Option	NPV costs	NPV benefits	Net economic benefits
New BH feeder, followed by non-network solution to defer preferred network option	-3.48	17.58	14.10

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. In order to facilitate non network solutions, we have already begun working with the community, retailers and non-network providers to seek out demand-side options to defer part or all of the preferred network solution. 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.

4.1.6 Option five: new TSE zone substation

An alternative option to address the capacity constraints at DC would be to establish a new zone substation at Templestowe (**TSE**), and build new sub-transmission lines. Additional feeders would also be required to alleviate forecast constraints on the feeders supplying the Box Hill Central Precinct (i.e. DC05, DC06 and DC12).

The economic timing of TSE zone substation is before December 2025. The benefits realised under this option include:

- a reduction in energy at risk at DC zone substation due to permanent load transfers to TSE
- alleviates forecast constraints on DC05, DC06 and DC12 feeders
- a reduction in customer outages due to less customers and shorter feeders in the northern DC supply region, as a result of establishing new TSE feeders.

This option, however, has a high comparative capital cost of approximately $20 million. As such, this is not a credible option to economically address the identified need and has not been explored further.

4.1.7 Option six: power factor correction

Installing capacitor banks may be used to reduce reactive power, and as such, can sometimes be a cheaper alternative to defer augmentation. Capacitor banks, however, are already installed at the DC zone substation and the surrounding street circuits (such that the network operates at close to unity power factor).

Consequently, this option is not technically feasible as the network is fully compensated and further capacitors will not deliver any material load reduction. The economics of this option, therefore, has 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 forecasts, assumed discount rates, and the capital and operating expenditure forecasts. Two extreme scenarios were applied (equal to ±4% for demand forecasts, and ±10% for other variables), reflecting best and worst-case scenarios.[5]

The results found the ranking of the preferred option (option 1) remains unchanged in under the 'best case' scenario. In the 'worst case' scenario, using a non-network solution to defer the fourth transformer and two feeders by one year, marginally out ranks the preferred option due to the lower residual energy at risk.

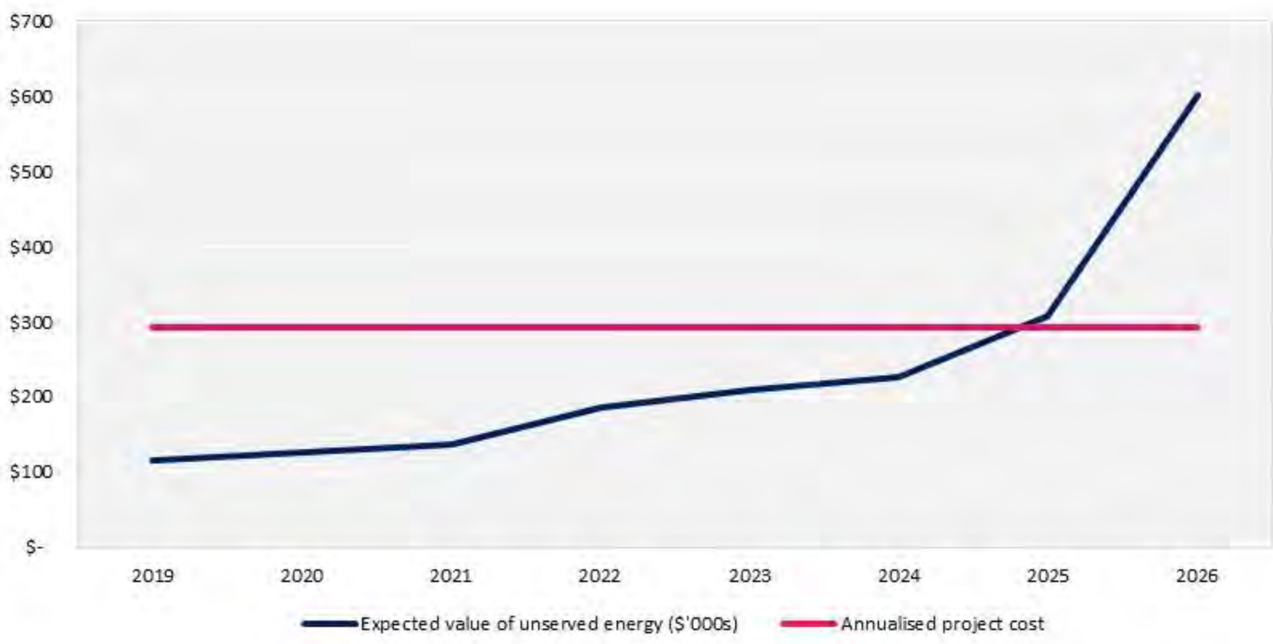
5 The sensitivity variance for demand forecasts (±4%) is consistent with the difference in growth between NIEIR's base, high and low forecast scenarios.

5 Recommendation

The preferred option, as set out in section 4, is to install two new feeders and a fourth transformer at DC. The required changes to the DC zone substation and distribution feeder network are shown in appendix B.

A detailed economic assessment was also performed to evaluate the optimum timing of the preferred network option. As shown in figure 8, the net market benefits of the preferred option, post the installation of the BH feeder, exceeds the annualised cost of the fourth transformer and two feeders in 2025. This demonstrates that the optimal timing for commissioning the fourth transformer and two feeders is before December 2024.

Figure 8 Timing assessment of the preferred option ($'000s, 2019)



Source: United Energy

The forecast capital and operating expenditure requirements for the 2021–2026 regulatory period are outlined in table 8. These forecasts have been developed in calendar year terms, and converted to financial years in our consolidated expenditure modelling following changes to our reporting period (as required by the Victorian Government and the Australian Energy Regulator).

Table 8 Expenditure forecasts for preferred option ($ million, 2019)

Expenditure forecast	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Capital expenditure	-	-	4.13	2.04	-	6.17
Operating expenditure	0.01	0.01	0.01	0.04	0.07	0.15
Total	**0.01**	**0.01**	**4.14**	**2.08**	**0.07**	**6.32**

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

A DC area demand growth

The growth in the DC supply area in recent years is supported by the series of figures below. These show the before and after images of the urban landscape at four key sites, and an overview of the planning approvals and new developments in Box Hill Central and Doncaster Hill.

A.1 Photos of growth in DC supply area

A.1.1 Box Hill precinct skyscrapers

Planning regulations in the Box Hill precinct now have unlimited height restrictions, which are leading the development of skyscrapers normally only seen in and around the Melbourne CBD. We have received a steady stream of application from other similar developments in this area.

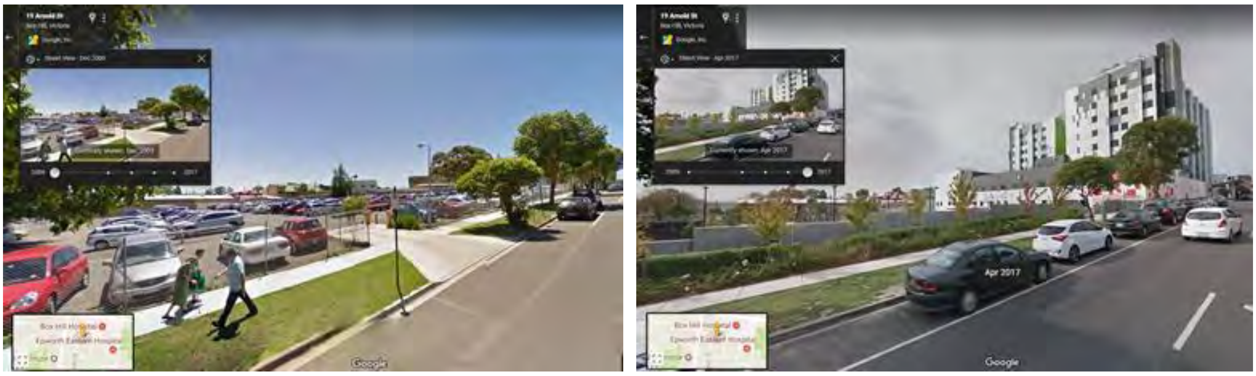
Figure 9 Box Hill precinct skyscrapers: before and after

Source: Google Maps

A.1.2 Box Hill Hospital

The development of the Box Hill Hospital has occurred with ongoing major expansion of the site and its surroundings. A number of commercial and community service developments are also occurring in this area.

Figure 10 Box Hill Hospital: before and after

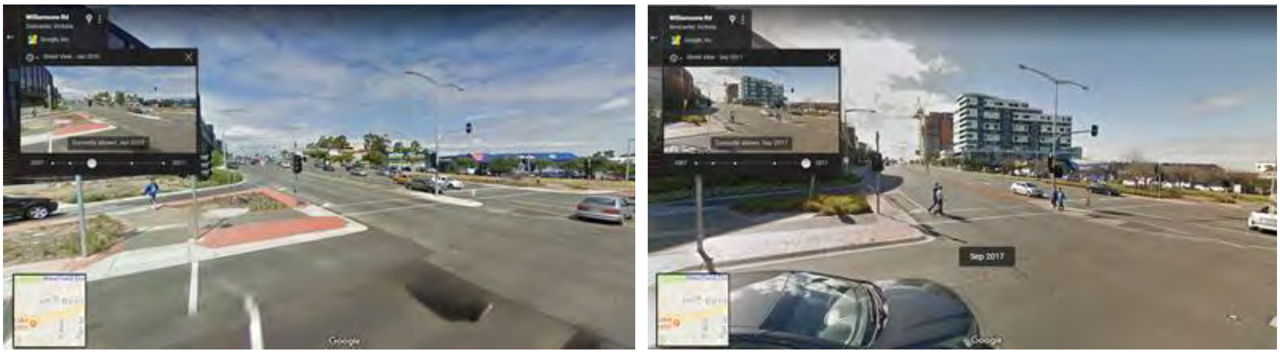


Source: Google Maps

A.1.3 Doncaster Hill precinct

The prevalence of high-density luxury style apartments has changed the landscape on Doncaster Hill. Planning regulations for this precinct now have a maximum of 10 storey height restriction. We have received numerous applications from other similar developments within this Precinct.

Figure 11 Doncaster Hill precinct: before and after



Source: Google Maps

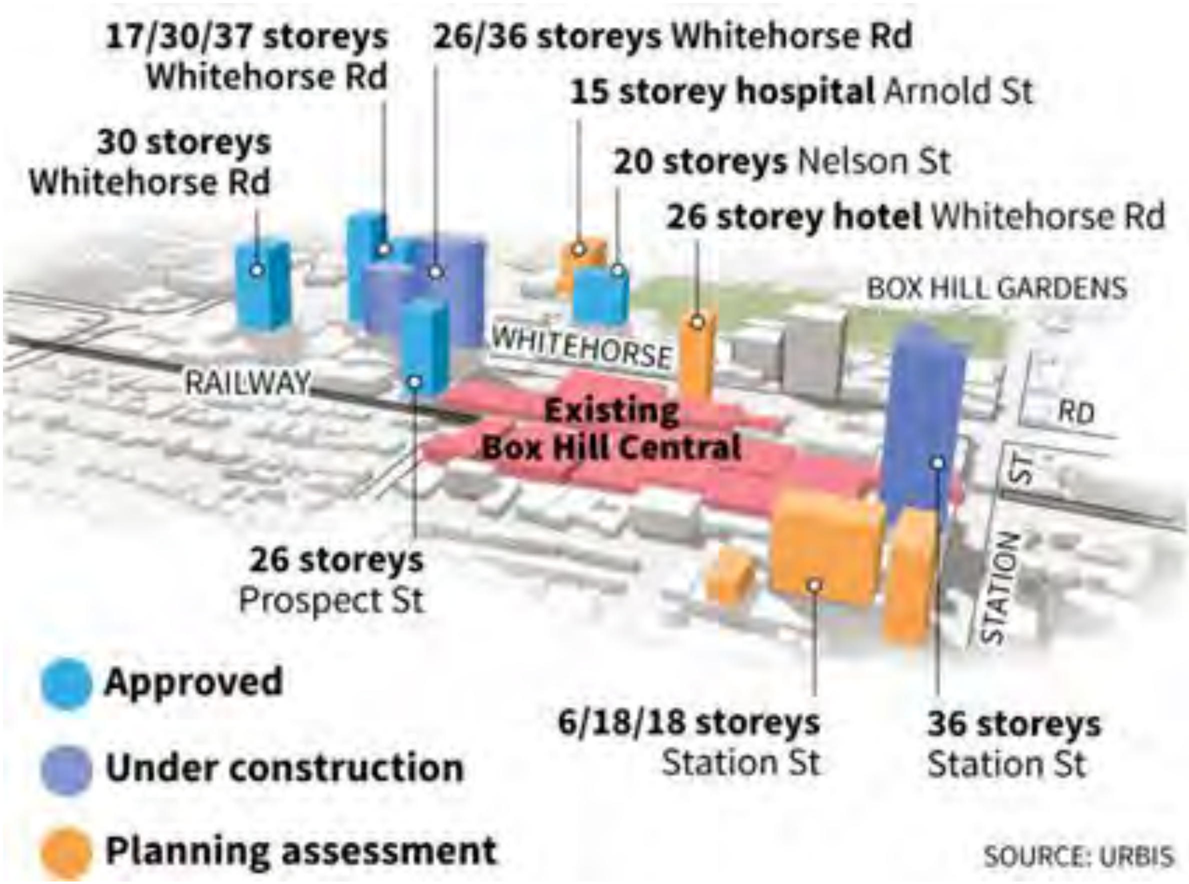
A.1.4 High-density developments

The photos below also provide an example of how multi-storey high-density apartments are driving demand growth in the existing urbanised areas by replacing the existing low-density dwellings.

Figure 12 High-density developments: before and after

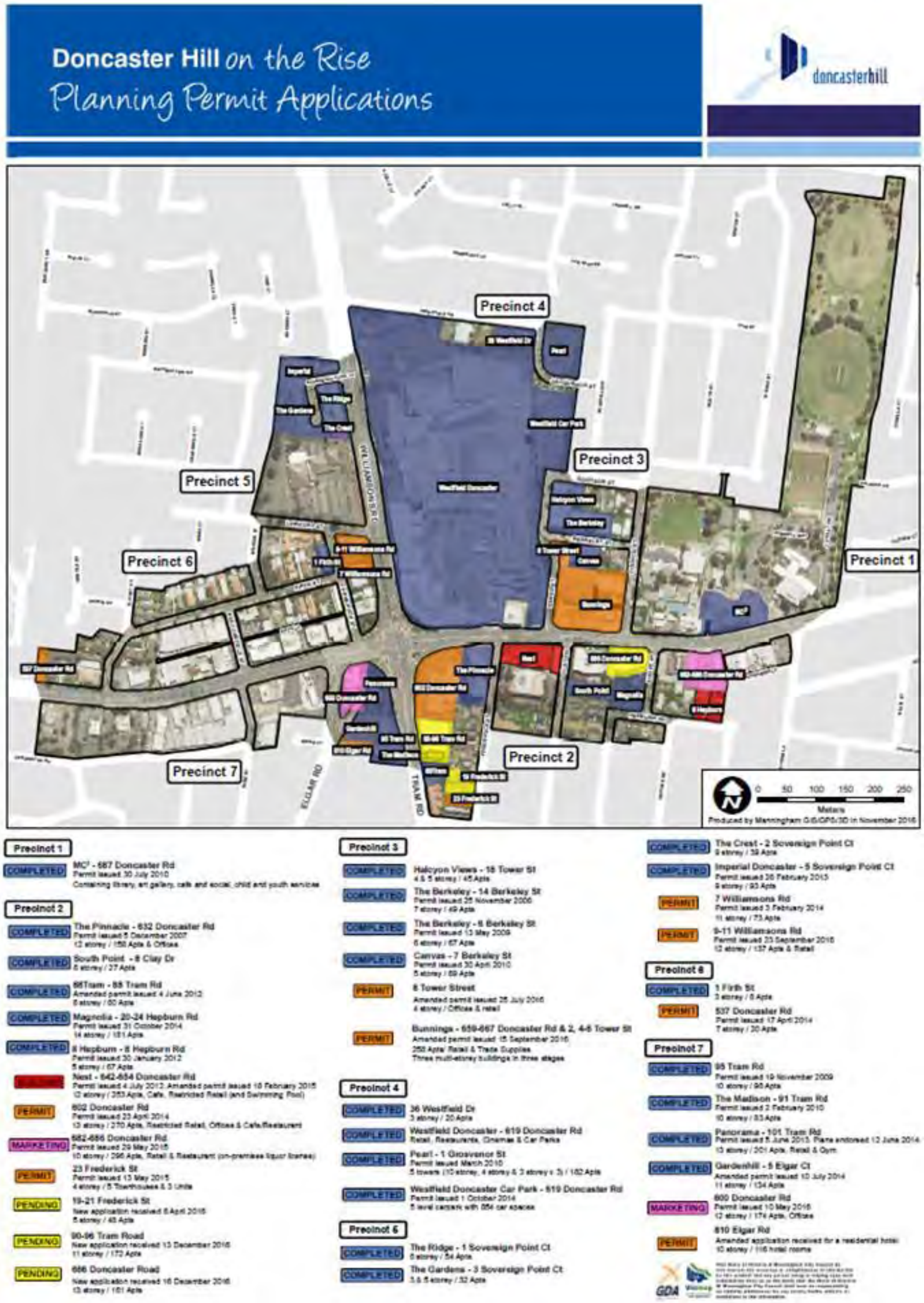
Source: Google Maps

A.2 New developments: Box Hill Central



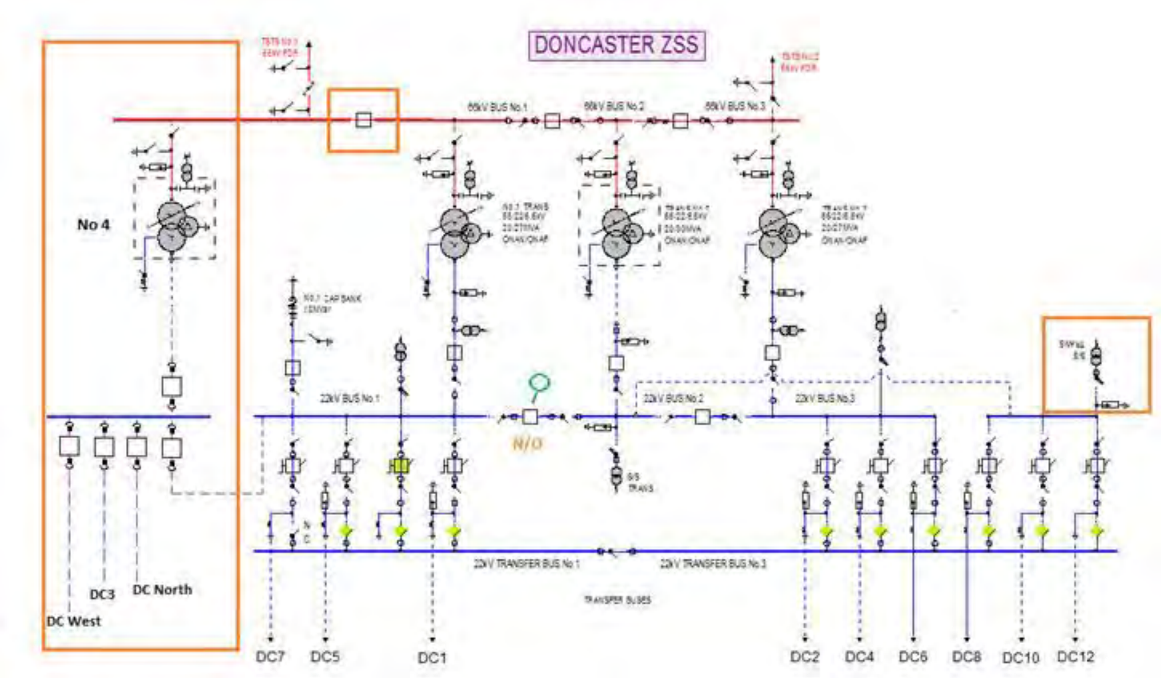
Source: Urbis

A.3 New developments: Doncaster Hill



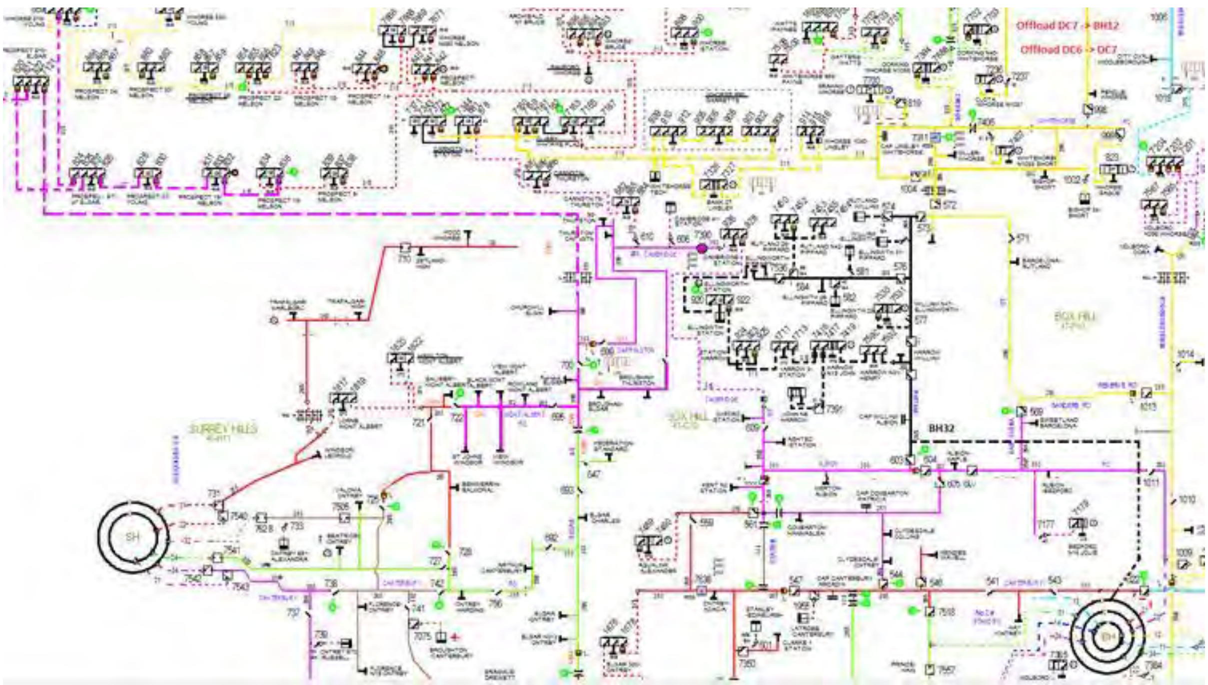
B Design of preferred option

Figure 13 Proposed DC zone substation arrangement



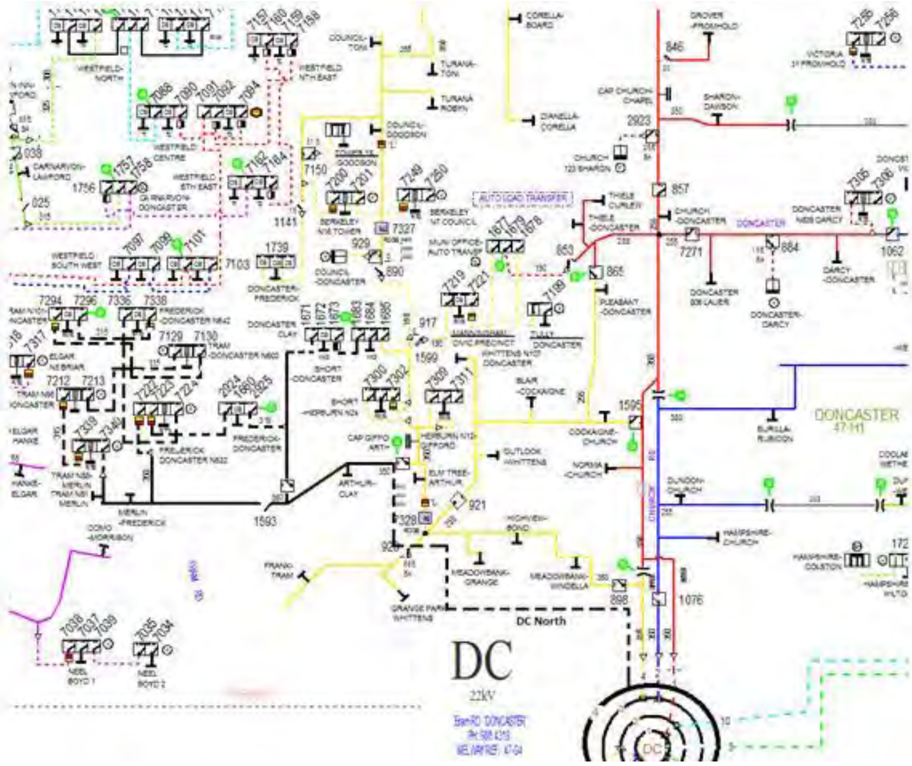
Source: United Energy

Figure 14 Proposed BH feeder (in black)



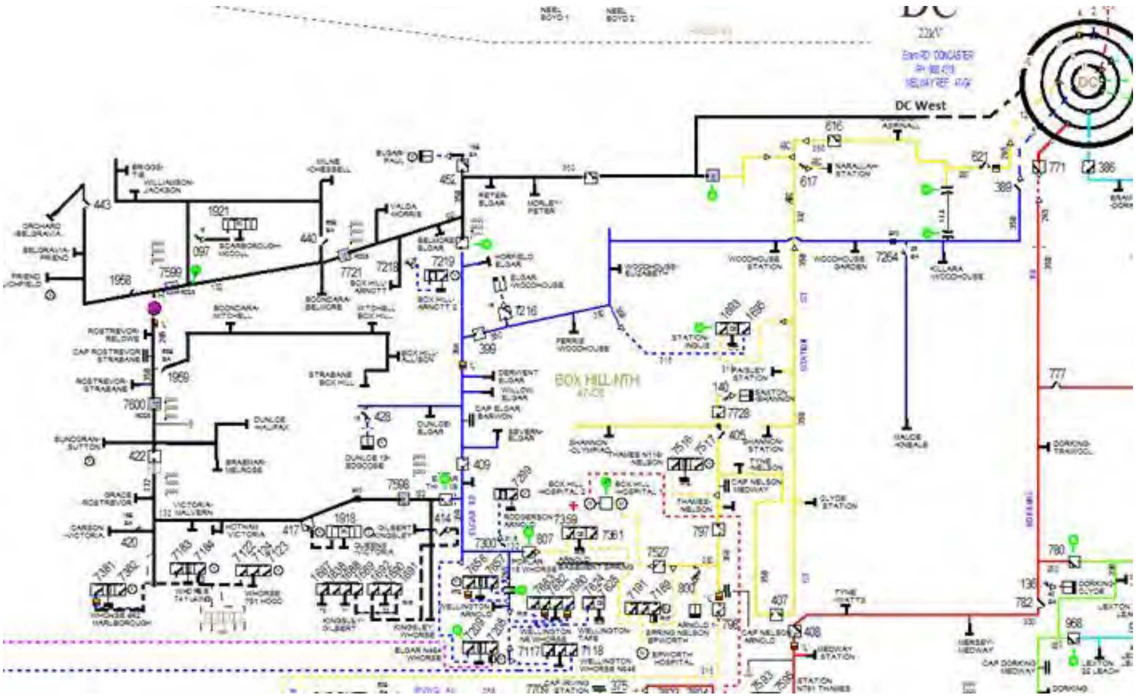
Source: United Energy

Figure 15 Proposed DC feeder north (in black)



Source: United Energy

Figure 16 Proposed DC feeder west (in black)



Source: United Energy