Augmentation expenditure: major projects

Revised negotiating position for the Customer Forum

8 October 2018

1. Negotiation scope

The augmentation expenditure (augex) for major projects is in scope of the proposed expenditure negotiations between AusNet Services and the Customer Forum and is also in scope of the negotiations that will be oversighted by the Australian Energy Regulator (AER).

AusNet Services is seeking to negotiate with the Customer Forum on options for two major augex projects in the 2021-25 period to address network constraints in key growth corridors at Clyde North and Doreen. The options include a preferred network option and alternatives (including deferral of the network augmentation and non-network options).

The Customer Forum's input is sought on their preferred price-service trade-off, based on their understanding of AusNet Services' customer preferences. If the Customer Forum chooses options that have a poorer reliability outcome relative to the preferred network project, AusNet Services would seek to make an appropriate adjustment to its Service Target Performance Incentive Scheme (STPIS) targets.

Additional questions have been posed by AusNet Services to the Customer Forum as part of the negotiation process in relation to the augex major projects. These are shown below. The expectation is that the Customer Forum will answer these questions as part of the negotiation process.

Box 1: Questions for the Customer Forum

- Do the proposed projects (i.e. the preferred network options) strike the right balance between cost and reliable supply to customers?
- Would customers be willing to consider project deferrals that would reduce costs but reduce network reliability?
- Have the customer outcomes of a range of network and non-network options been sufficiently considered?
- Do you have any comments about the design of non-network options, including non-network options that involve customer participation or impacts such as demand management/response or appliance control?
- Is further research and/or engagement, beyond which is planned, required to form a view on this issue?

2. Project options to address constraints

AusNet Services is proposing augmentation expenditure in two areas of its network that are experiencing strong population growth and hence growth in peak demand. These areas are Clyde North and Doreen. Expenditure is needed to secure reliable supply to the growing customer base in these areas. Figure 1 shows the location of these areas in relation to Melbourne's growth corridors.

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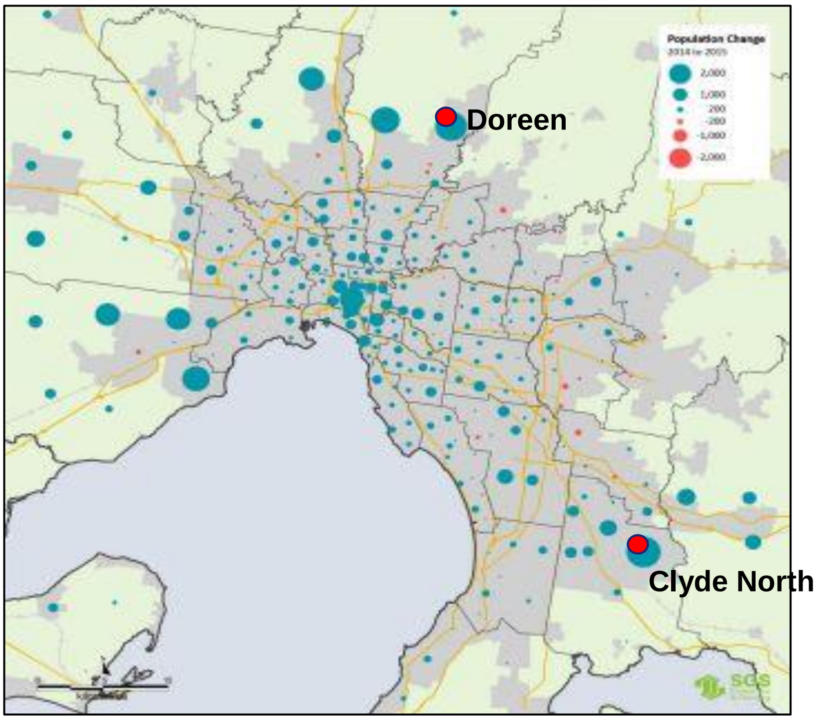
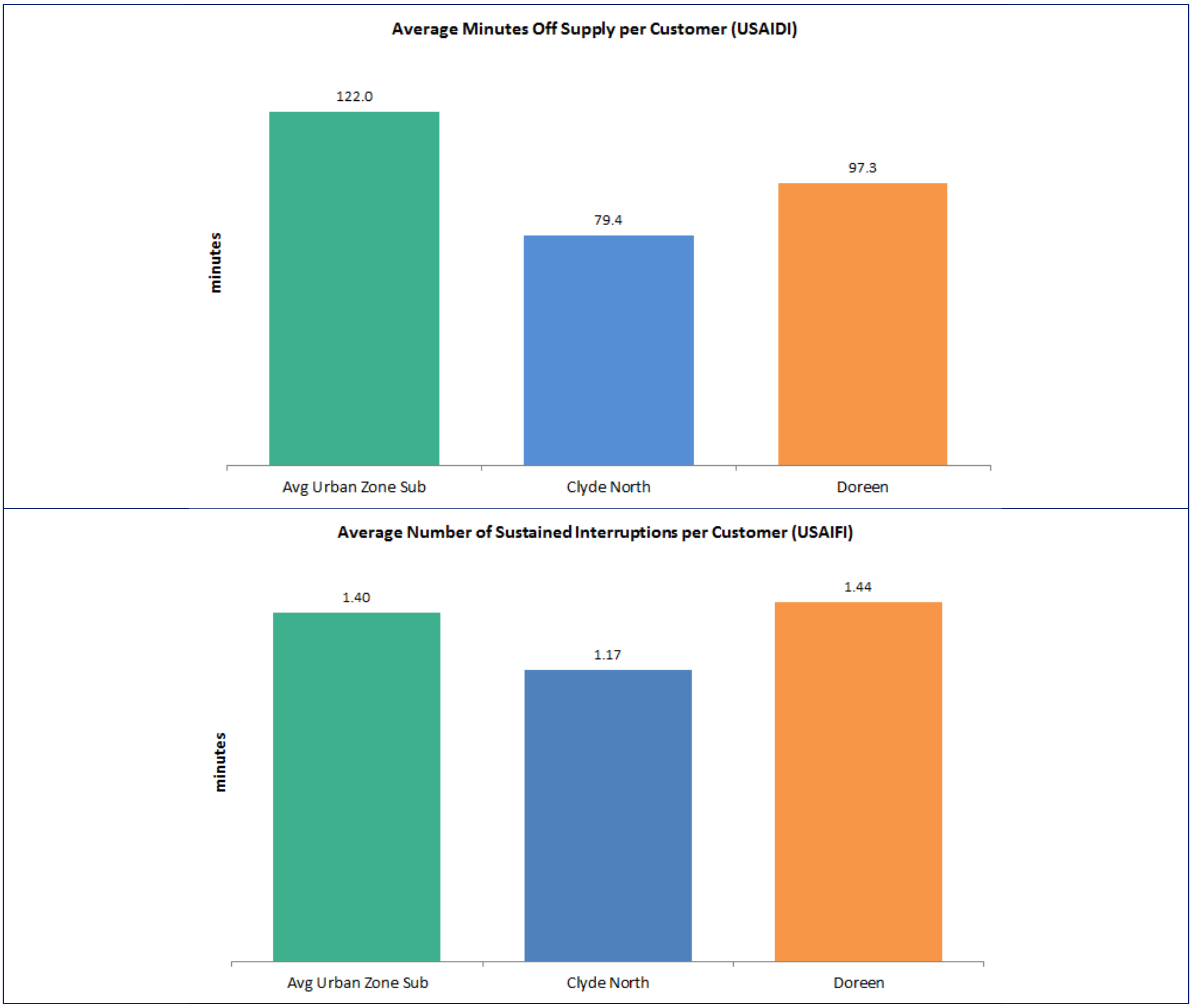
Figure 1: Melbourne's population growth



Source: SGS Economics and Planning 2016

Past reliability performance at the Clyde North and Doreen zone substations in terms of outage duration and frequency, compared to the average across urban zone substations, is shown in Figure 2. While customers at Clyde North and Doreen have experienced relatively good reliability over 2013-17 compared to customers at other urban zone sub-stations, the augmentation projects are required due to the rapid population increase that is occurring in these areas, impacting the consequence of an outage (i.e. the amount of lost load).

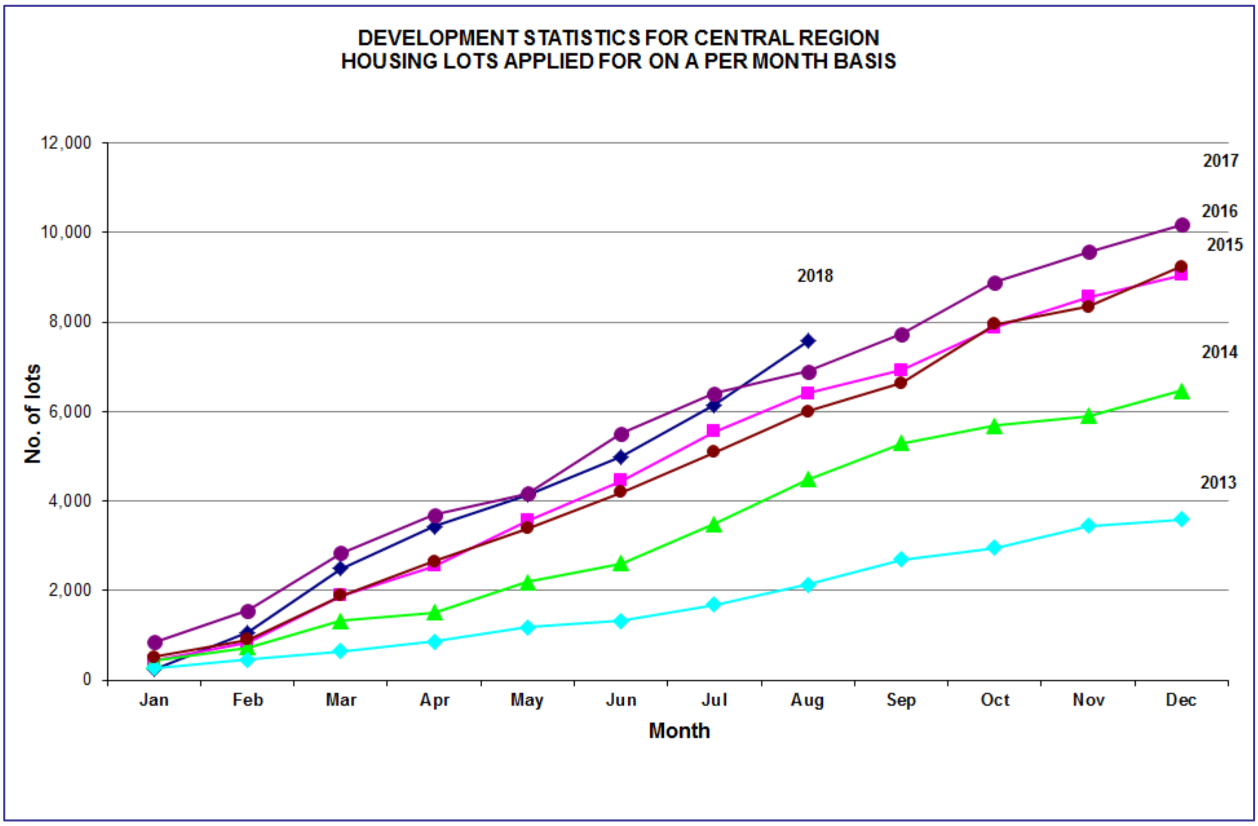
Figure 2: Average Outage Duration (mins) and average outage frequency (no.): 2013-2017 average



Note: This USAIDI (unplanned system average interruption duration index) shown in the top half of this figure is the average for each station over a 5-year period from 2013-17. USAIDI accounts for unplanned customer outage events that arise from a variety of causes such as possums, fallen trees, or equipment failure. The outage duration data shown in Tables 3 and 6 below are different to USAIDI. The outage data in the tables is limited to outages arising from expected equipment outages at the zone substations under the different augmentation scenarios.

While specific information is provided on growth in the Clyde North and Doreen corridors below, a leading indicator of growth is housing lot connection applications. Applications for supply to new lots are typically 12 months ahead of actual network demand in the area. In 2018 there has been strong growth in applications in AusNet Services' Central Region, which includes Clyde North and Doreen.

Figure 3: Housing lot applications Central Region



The chart of lot applications shows very strong growth in 2018. AusNet Services has received applications for 7,574 lots for the 2018 year (8 months) compared to 6,898 for the same period in 2017. This is a 9% increase from 2017. Based on a monthly application average of 946 lots this year, we expect to receive 11,352 lot applications for the 2018 calendar year compared to 10,172 in 2017 and 9,232 in 2016.

The south-east Clyde North /Pakenham growth corridor of the Central Region is currently developing more quickly than the northern corridor of the Central Region where the Doreen growth corridor is located.

2.1 Clyde North

Requirement for augmentation

The existing zone substation at Clyde North was commissioned in 2005 to meet load growth in the South-Eastern growth corridor of metropolitan Melbourne. The station was constructed with two 66/22 kV transformers to meet demand at that time, with room for a third transformation installation in the future. Demand at the station is growing at rate above 4 Mega Volt Amps (MVA) per annum, reaching the firm capacity of the station. As shown in the following figures, this trend is expected to continue.

Figure 4 shows that the customer growth at Clyde North has been substantially higher than on average across our network.

Augmentation expenditure: major projects

Figure 4: Clyde North customer growth 2012-17

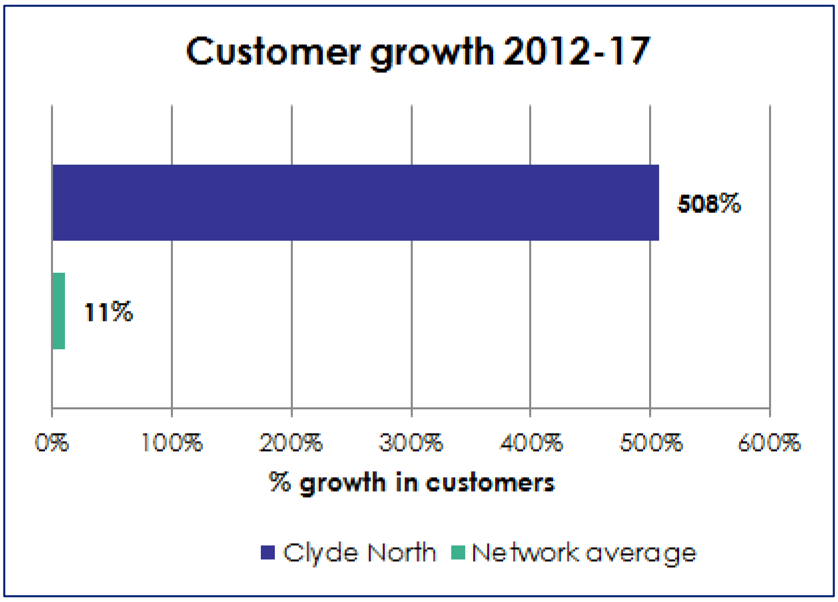
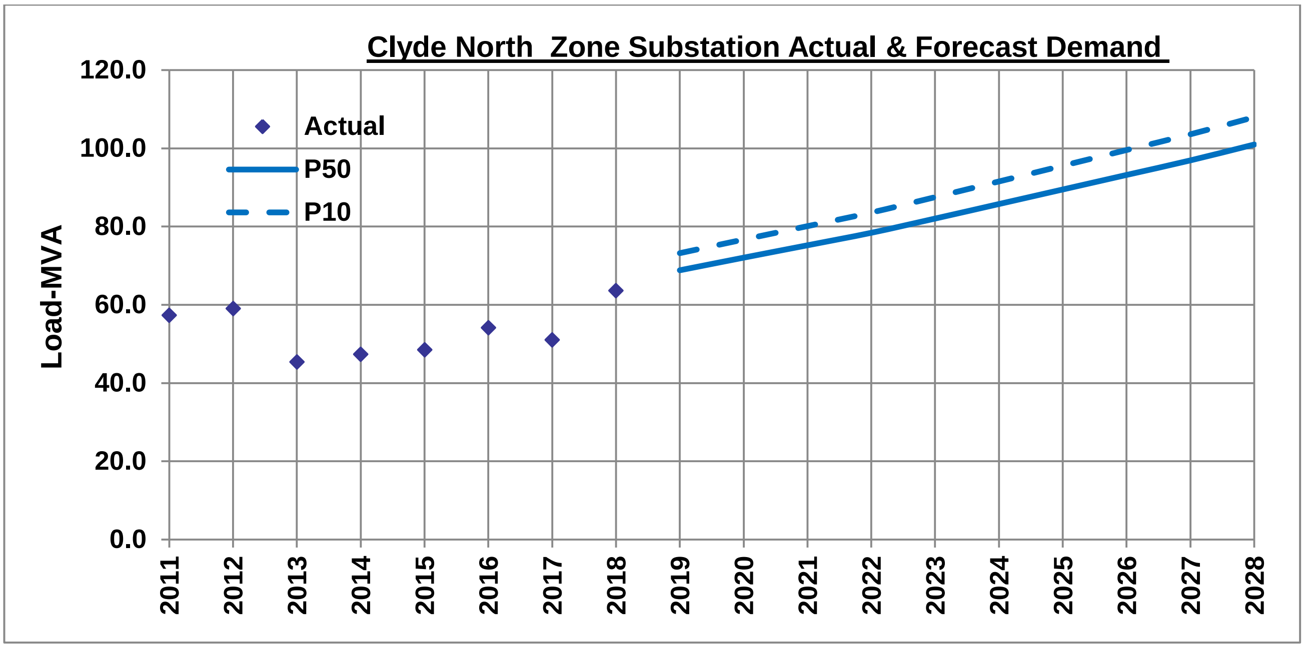


Figure 5 shows that the high growth is expected to continue, driving increasing demand growth. Figure 3 provides two demand forecasts:

- 50 POE: This demand forecast has a 50% probability of exceedance. That is, it is expected to be exceeded on average, 5 years in 10. This means this is a lower, more conservative forecast;
- 10 POE: This demand forecast has a 10% probability of exceedance. That is, it is expected to be exceeded on average, 1 year in 10. This means this is a higher, more aggressive forecast that is less likely to be exceeded.

Even the lower 50 POE forecast shows strong expected demand growth over the period to 2025 and beyond.

Figure 5: Clyde North forecast maximum demand– Actual, 10 and 50 POE



Augmentation expenditure: major projects

Underlying the strong growth in demand is expected strong growth in customer numbers. Historical and forecast customers by customer type are shown below. Customer numbers are forecast to increase by 34% from the end of 2020 to 2025, or average annual growth of 6%. Residential customers account for 98% of customers over the 2021-25 period.

Table 1: Clyde North customer number by customer type 2011 to 2025

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	13,677	14,684	16,179	17,912	19,640	21,783	23,503	25,253	27,003	28,753	30,503	32,565	34,627	36,689	38,751
Industrial	65	67	64	64	76	82	84	85	86	87	88	89	90	91	92
Commercial	437	450	484	501	522	543	538	549	560	571	582	594	606	618	630
Total	14,179	15,201	16,727	18,477	20,238	22,408	24,125	25,887	27,649	29,411	31,173	33,248	35,323	37,398	39,473

Note: Customer numbers from 2017 are forecast.

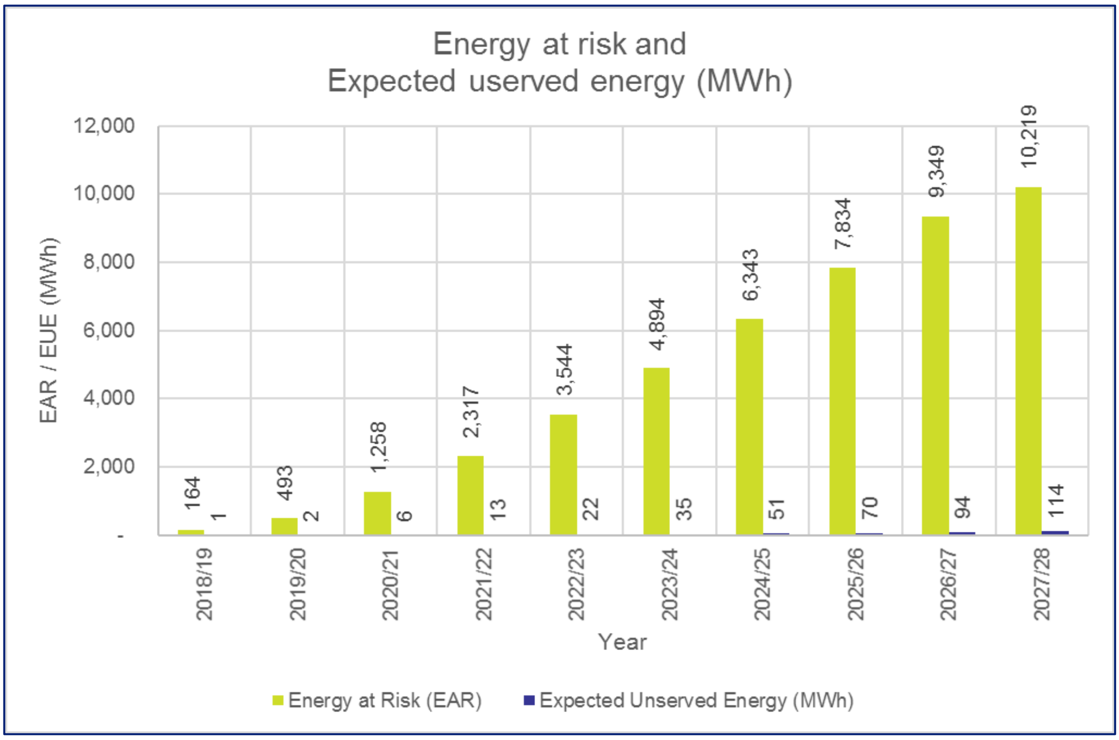
To prepare our customer and demand forecasts, AusNet Services uses official planning and population forecasts published by the Victorian Government. The relevant reports and data can be found here:

https://www.planning.vic.gov.au/land-use-and-population-research/victoria-in-future-2016

In the absence of augmentation, the energy at risk (or the amount of energy demanded by customers that may not be supplied) rises. This is shown in Figure 6.

In the figure, the energy at risk (EAR) represents the energy that would not be supplied if one transformer was out of service for the entire year. By 2025, this reaches 7,834 MWh if no investment is made to increase the capacity of the zone substation.

Figure 6: Base Case- Clyde North energy at risk and expected unserved energy



If an outage did occur due to a transformer failure, significant time is typically needed to repair or replace the transformer. Two spare transformers are available in the Central and East region (which have 120 power transformers). If repairs are possible, the time taken to repair the transformer will depend on a number of factors including the nature of the failure. At least a month is typically needed to replace a transformer with a spare. If a spare transformer is unavailable, accessing a new transformer has a lead time of at least nine months as they are made to order. More detail on transformer outages and time out of service is provided in an attachment to this note.

Lengthy outages for connected customers are typically able to be avoided or minimised through a range of actions. However, there is a much higher customer risk if another transformer at site was to develop a problem. Outages are typically experienced when the fault first occurs before the faulty transformer is isolated. Once this is done, the load may be able to be met by the remaining transformer capacity. Where this is not possible or there is a lengthy outage of the transformer while it is repaired or replaced, outages are minimised by a combination of:

- temporary load transfers between zone substations;
- rotating the feeders off supply to ensure that no feeder is shed for more than two hours at a time[1]; and
- installing diesel generators to provide network support.

When planning for investments to augment the zone substations, the likelihood or probably of this kind of transformer failure is also considered. The probability weighted expected unserved energy (EUE) is much lower due to the low probability of a transformer being unavailable for service.

The expected unserved energy per year is forecast to increase from around 1 MWh in 2018/19 to 114 MWh in 2027/28. This represents approximately 7,600 customers off supply for an entire day in that year. However, in reality, either the extended outage would occur (as described above) or no outage would occur.

Investment to expand the capacity of the Clyde North zone substation is economically justified by 2023. A third power transformer is proposed for the zone substation to increase capacity and to address the reliability risk to customers.

Augmentation options

Based on the timing and extent of demand growth and risk to customer supply reliability, AusNet Services' preferred network solution is to augment the Clyde North substation capacity by installing a third transformer in 2023.

Additional options, with different price-reliability trade-offs are presented for consideration by the Customer Forum. The alternative options are to:

- Do nothing;
- Defer the transformer project by:
  - one year; or
  - by two years;
- Use non-network solutions:
  - embedded generation (diesel generation);
  - large scale storage (batteries); and
- Implement a hybrid network/non-network option that uses demand response and behind the meter batteries from 2021 to 2025 to manage the risk of an outage, deferring the 3rd transformer out of the regulatory period to 2026.

The options are shown in Table 2.

[1] The number of feeders off supply depends on various factors including the customer demand, the amount of load shedding required at the time and any restrictions on shedding particular feeders, such as those providing critical supplies.

Table 2: Clyde North augmentation options

Option	Description
Base Case Option: Do Nothing	No investment is made to augment the Clyde North zone substation or to undertake alternative works
Network options	
Preferred option: Install 3rd 20/33 MVA transformer by 2023	The preferred option is to install a 3rd and final transformer at Clyde North Zone substation and a 3rd switchboard. Works would be undertaken over the 2021 to 2023 period with the new transformer and switchboard commissioned in 2023. **Note:** The previous costs of this project included a larger scope of works that also included the installation of a new feeder. The feeder is proceeding but is a customer funded project that is not dependent on or related to the transformer replacement .
Install 3rd 20/33 MVA transformer by 2024	1-year deferral of the preferred option. Works would be undertaken over the 2022 to 2024 period with the new transformer and switchboard commissioned in 2024.
Install 3rd 20/33 MVA transformer by 2025	2-year deferral of the preferred option. Works would be undertaken over the 2023 to 2025 period with the new transformer and switchboard commissioned in 2025.
Non-network options	
Embedded generation	20 MW diesel generation – this is mobile generation owned by AusNet Services providing network support Assumed cost: CAPEX - $0.5 million / MW OPEX - $0.5 million / MW for fuel costs etc.
Energy storage (battery)	20MW/ 20 MWh – Network battery generation owned by AusNet Services providing network support. Assumed cost: $4 million /MWh (based on previous experience with grid scale energy storage). Note: this assumes 20 MW is available for 1 hour. However peak lasts for ~4hrs so this will not address all risk.
Hybrid Network/Non-network option	
Demand response and network support contracted from an aggregator from 2021 and 3rd transformer deferred to 2026	10% of customers deliver a 40% demand reduction – informed by the Peak Partners trial (described below).

Augmentation expenditure: major projects

Option	Description
	$5,000 /MW of demand reduction capacity. 2 MW / 8 MWh of network support from an aggregator (e.g. of behind the meter solar/battery that can deliver 2MW at peak for four hours before it is discharged). Assumed cost: $20,000 /MW (based on previous experience with grid scale energy storage). Delays the installation of 3rd transformer at Clyde North Zone substation to 2026.

Peak Partners

Over the 2017-18 summer, AusNet Services undertook a demand management trial in Clyde North. This was funded by the Demand Management Innovation Allowance. The following demand management offerings were tested:

- Behavioural response to a Critical Peak Rebate incentive, with AMI data portal (delayed data);
- Behavioural response to a Critical Peak Rebate incentive, with real-time data portal;
- Air conditioning load control (marketed as 'Autopilot) via Demand Response Enabling Device;
- Supply Capacity Control (marketed as 'Essential Power') via the AMI smart meter.

Overall, 82 customers were enrolled across the four offerings, sourced from a local primary school, a letter-drop and emails to myHomeEnergy customers.

The results from the Critical Peak Rebate trial were strong and averaged a 40% reduction in demand across the 72 customers enrolled for the Critical Peak Rebate on the 3 hottest days of the project. The incentive rate was set to $5/kWh, and payments to customers varied widely from around $5 to $30 per event.

Only 5 customers were enrolled in the AutoPilot and Essential Power offerings respectively, which was too small a sample to draw robust conclusions around the degree of response. Technical learnings were achieved.

AusNet Services is currently assessing potential demand response initiatives for this summer. A key information gap is the degree to which customers' response will be sustained if the program is repeated over time. However, even where there is a diminishing response over time. In the context of deferring network augmentation, demand management is a short term solution that provides option value.

As shown in Table 3, the options for Clyde North have varying impacts on both cost to customers (over the short and long term) and reliability impacts. These trade-offs are plotted in the charts below, so the options can be readily compared.

Augmentation expenditure: major projects

Table 3: Comparison of Clyde North augmentation options

	Option (real $2020)	Capital cost ($M)	OPEX per annum ($M)	Present Value (PV) Project Cost ($M)	PV cost over 50 year asset life/ customer [1]	Average annual cost/ customer [2] (2021-25)	Total expected outage duration 2021-25 (minutes)
1	**Base Case Option:** Do Nothing	-	-	-	-	-	761
	Network options						
2	Preferred option: Transformer by 2023	$7.77	-	$6.82	$8.70	$0.35	224
3	1 year deferral (2024)	$7.84	-	$6.39	$8.41	$0.24	379
4	2 year deferral (2025)	$7.96	-	$6.42	$8.19	$0.14	556
	Non-network options						
5	Embedded generation	$10.73	$0.40	$12.25	$17.26	$1.03	224
6	Energy storage (battery)	$85.81	$0.43	$76.94	$110.33	$4.18	224
	Hybrid Network/Non-network option						
7	Demand response and network support contracted from an aggregator from 2021 and 3rd transformer deferred to 2026	$9.69	$0.58	$9.69	$14.12	$0.79	577

Notes:

1. The PV of cost over the 50 year asset life represents the revenue associated with the projects (i.e. opex and return on and return of capital), in present value terms.
2. The average annual cost per customer represents the revenue associated with the projects (i.e. opex and return on and return of capital) and is an annual average over 2021-25.
3. The final column shows the expected outage duration over the 5 year regulatory period due to an inability to meet demand in the event of a transformer failure. It is calculated by multiplying the number of minutes that the station would not be able to meet the demand in the event of a transformer failure by the probability of a transformer failure (assuming no load cycling between feeders) and average transformer outage duration. The number of customer that would be impacted by the outage would depend on how the outage is managed in practice.

The current level of supply reliability associated with the equipment at Clyde North is consistent with the preferred option (Option 2), i.e. 23 minutes in 2018.

Figure 7 plots the cost and reliability impact for customers during 2021-25. Note that the cost impact affects all customers, while the reliability impacts are only experienced by the 27,310 customers (99% residential) connected to Clyde North zone substation.

Augmentation expenditure: major projects

The figure shows that:

- The best reliability outcome is achieved by installing the 3rd transformer by 2025 (Option 2). This is the preferred option;
- While Options 3 and 4, the one and two year deferrals, have a lower short term cost than Option 2, the reliability impacts on the connected customers are relatively high;
- The non-network options have either far higher short term cost impacts (Options 5 and 6), or far worse reliability impacts (Option 7).

Figure 7: Price reliability trade-off – Clyde North - Short term

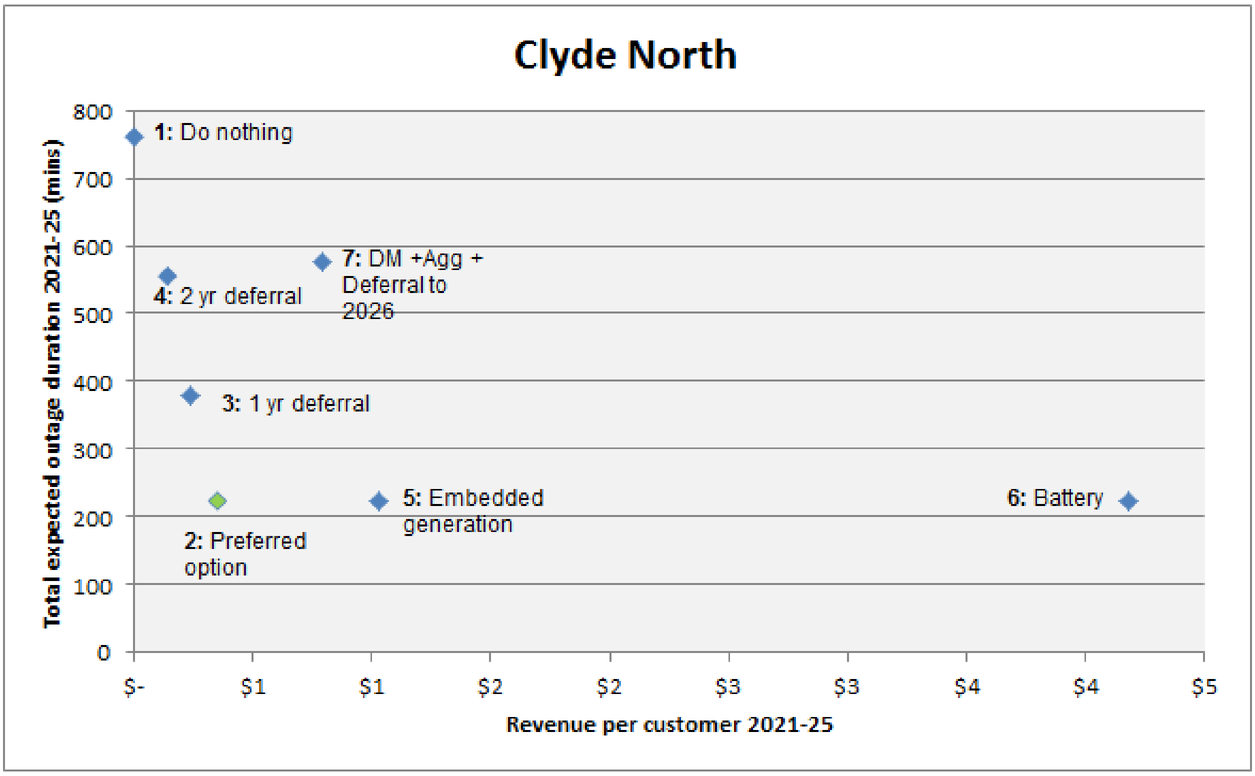
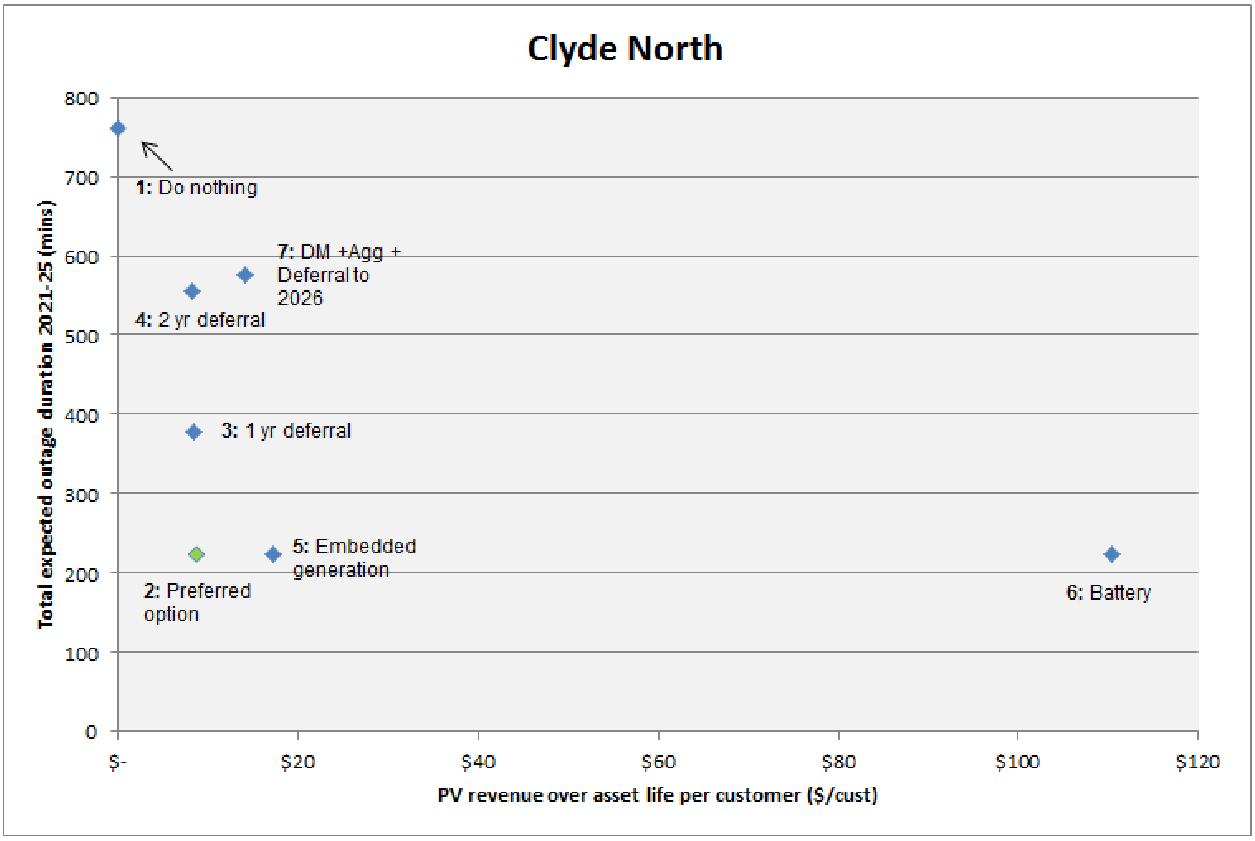


Figure 8 plots the long-term cost (revenue associated with the projects in present value terms) and reliability impact for customers during 2021-25 of the various options for Clyde North. This shows that:

- Over the long term, Option 2 (the preferred option) is the lowest cost to customers and equal first (with Options 5 and 6) for reliability;
- The one or two year deferral options (Options 3 and 4 respectively) has a very similar cost to customers over the long term as Option 2 (the preferred option), but are far worse for reliability;
- Non-network options are either have higher long-term cost impacts (Options 5 and 6) or far worse reliability impacts (Option 7).

Figure 8: Price reliability trade-off – Clyde North - Long term



2.2 Doreen

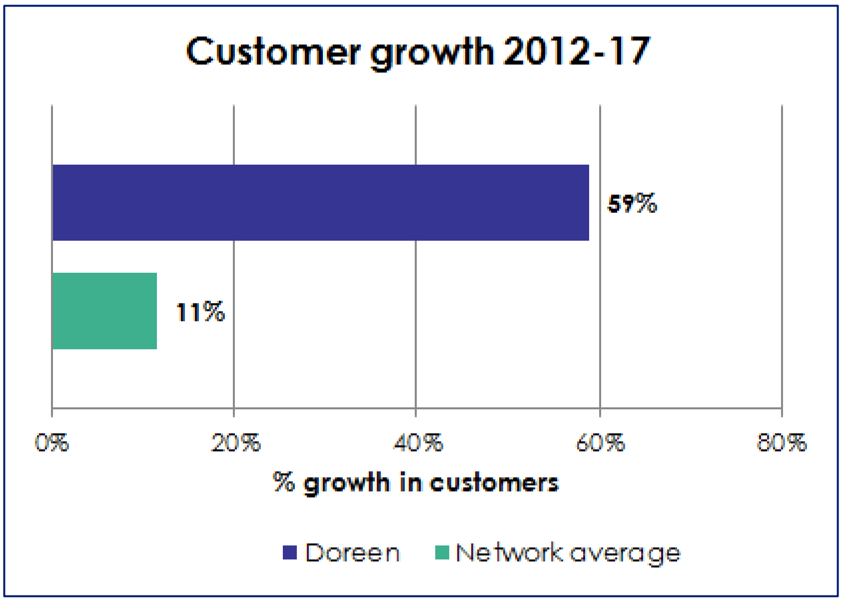
Requirement for augmentation

The Doreen Zone Substation, similar to the Clyde North Zone Substation, was constructed in 2006 to address residential population growth in the Northern Growth Corridor of Metropolitan Melbourne. The station was constructed with only two of the ultimate three 66/22 kV power transformers, as required by the demand experienced at the time.

Demand at the station is growing at rate of 2 MVA per annum reaching the firm capacity of the station. As shown in the following figures, this trend is expected to continue.

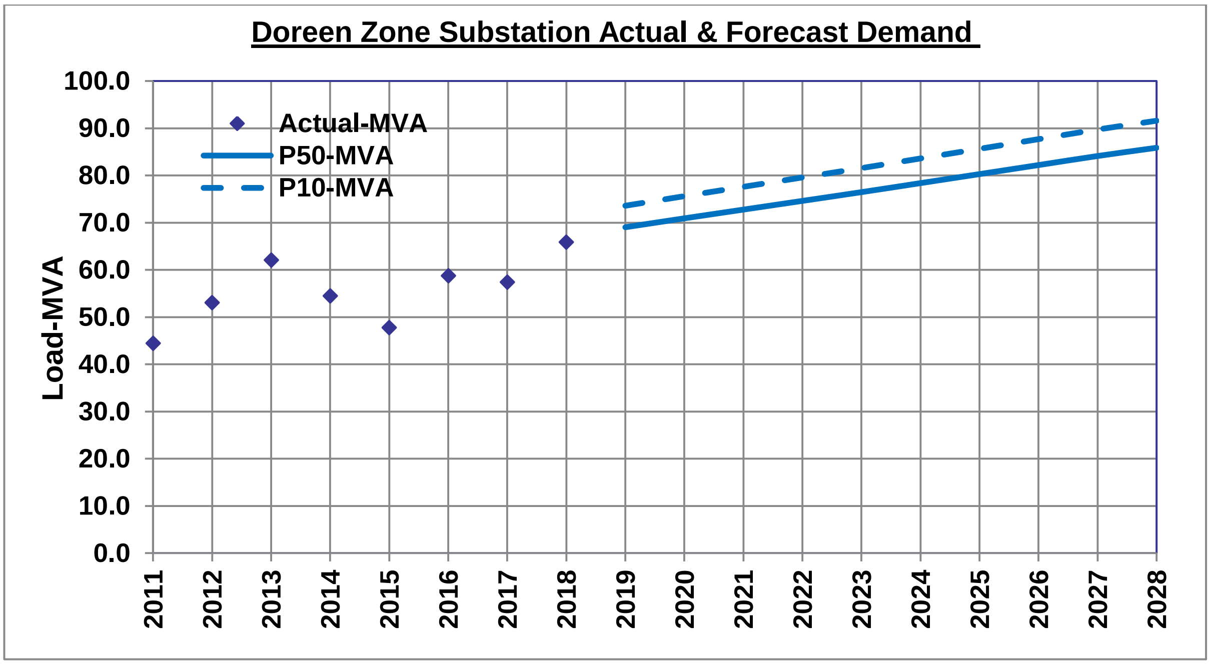
Figure 9 shows that the customer growth at Doreen has been substantially higher than on average across our network, though the growth is not as high as at Clyde North.

Figure 9: Doreen customer growth 2012-17



As shown in Figure 10, the high growth is expected to continue, driving increasing demand growth over the period to 2025 and beyond.

Figure 10: Doreen forecast maximum demand (zone sub coincident peak demand?) – 10 and 50 POE



Note: 50 POE: This demand forecast has a 50% probability of exceedance. 10 POE: This demand forecast has a 10% probability of exceedance.

Augmentation expenditure: major projects

Underlying the strong growth in demand is expected strong growth in customer numbers. Historical and forecast customers by customer type are shown below. Customer numbers are forecast to increase by 16% from the end of 2020 to 2025, or average annual growth of 3%. Residential customers account for 97% of customers over the 2021-25 period.

Table 4: Doreen customer number by customer type 2011 to 2025

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	18,581	20,211	21,332	22,558	24,165	25,214	26,159	27,136	28,113	29,090	30,067	31,009	31,951	32,893	33,835
Industrial	76	77	80	76	78	79	80	81	82	83	84	86	88	90	92
Commercial	771	827	832	856	884	872	886	895	904	913	922	931	940	949	958
Total	19,428	21,115	22,244	23,490	25,127	26,165	27,125	28,112	29,099	30,086	31,073	32,026	32,979	33,932	34,885

Note: Customer numbers from 2017 are forecast.

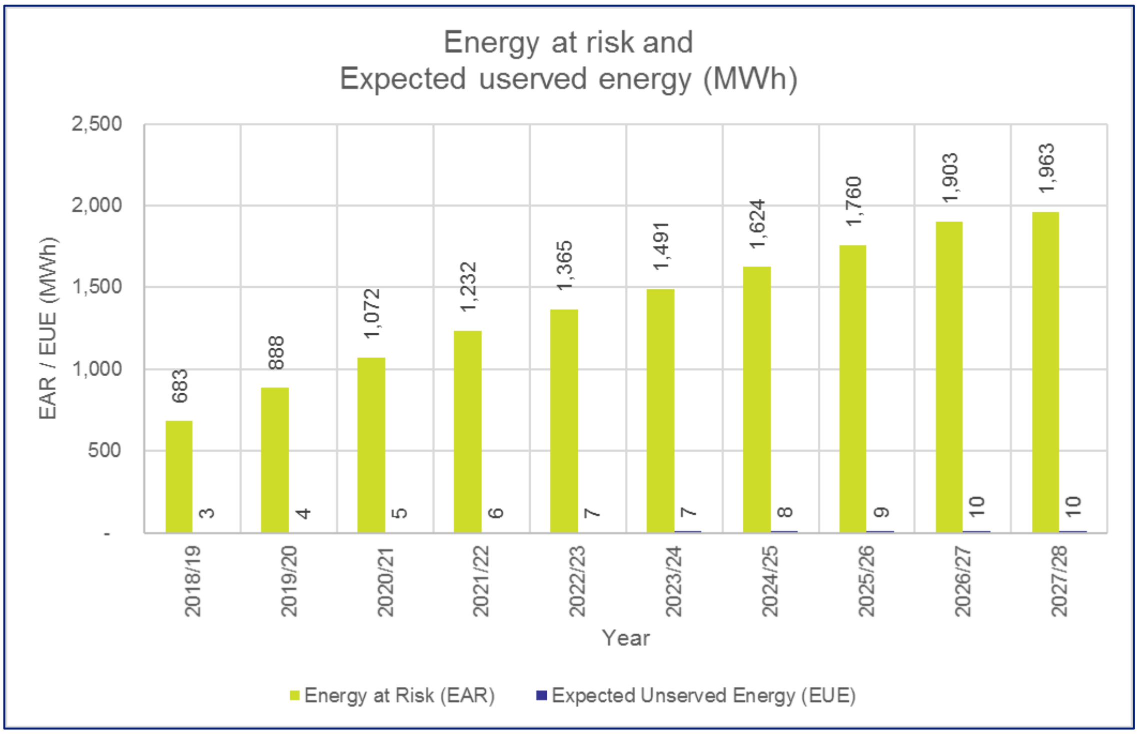
In the absence of augmentation, the energy at risk (or the amount of energy demanded by customers that may not be supplied) rises. This is shown in Figure 11.

In the figure, the energy at risk (EAR) represents the energy that we would not able to supply if one transformer was out of service for the entire year. By 2025, this reaches 1,760 MWh (if no investment is made to increase the capacity of the zone substation). As with Clyde North, if a transformer did fail, an extended outage could occur, which need to be managed reactively at a high cost.

When planning for investments to augment the zone substations, the likelihood or probably of this kind of transformer failure is also considered. The probability weighted expected unserved energy (EUE) is much lower due to the low probability of a transformer being unavailable for service.

The expected unserved energy per year is forecast to increase from around 3 MWh in 2018/19 to 10 MWh in 2027/28. This represents approximately 670 customers off supply for an entire day in that year (although, as above, this scenario is not particularly meaningful as either the extended outage, or no outage, would occur).

Figure 11: Base Case- Doreen energy at risk and expected unserved energy



Augmentation options

Based on the timing and extent of demand growth and risk to customer supply reliability, AusNet Services' preferred network augment option is to install the third transformer in 2023. Additional options, with different price-reliability trade-offs are presented for consideration by the Customer Forum. The alternative options are to:

- Defer the transformer project by two years;
- Use non-network solutions:
  - embedded generation (diesel generation);
  - large scale storage (batteries); and
- A hybrid network/non-network option that uses demand response and behind the meter batteries from 2021 to 2025 to manage the risk of an outage, deferring the 3rd transformer out of the regulatory period to 2026.

The options are shown in Table 5.

Table 5: Doreen augmentation options

Option	Description
Base Case Option: Do Nothing	No investment is made to augment the Doreen zone substation or to undertake alternative works.
Network options	
Preferred option: Install 3rd 20/33 MVA transformer by 2025	Install a 3rd and final transformer at Doreen Zone substation. Works over 2024-2025, commissioned in 2025.
Install 3rd 20/33 MVA transformer by 2027 (2 year deferral out of period)	2-year deferral Works over 2026-2027, commissioned in 2027. Note: this option has the same impact as "Do Nothing" within the 2021-25 period but has different cost and outage impacts over the longer term.
Non-network options	
Embedded generation	20 MW diesel generation Assumed cost: CAPEX - $0.5 million /MW OPEX - $0.5 million /MW for fuel costs etc.
Energy storage (battery)	20MW / 20 MWh. Assumed cost: $4 million /MWh (based on previous experience with grid scale energy storage). Note: this assumes 20 MW available for 1 hour. However peak lasts for ~4hrs so this will not address all risk.

Augmentation expenditure: major projects

Option	Description
Hybrid Network/Non-network options	
Demand response and network support contracted from an aggregator from 2021 and 3rd transformer deferred to 2026	10% of customers deliver a 40% demand reduction. $5,000 /MW of demand reduction capacity. 2 MW / 8 MWh of network support from an aggregator (e.g. of behind the meter solar/battery that can deliver 2MW at peak for four hours before it is discharged). Assumed cost: $20,000/MW (based on previous experience with grid scale energy storage). Delays the installation of 3rd transformer at Doreen Zone substation to 2026.

As shown in Table 6, the options for Doreen have varying impacts on both cost to customers (over the short and long term) and reliability impacts. These trade-offs are plotted in the charts below, so the options can be readily compared.

Table 6: Comparison of Doreen augmentation options

	Option	Capital cost ($M)	OPEX per annum ($M)	Present Value (PV) Project Cost ($M)	PV cost over 50 year asset life/ customer [1]	Average annual cost/ customer [2] (2021-25)	Total expected outage duration 2021-25 (minutes)
1	**Base Case Option:** Do Nothing	-	-	-	-	-	138
	Network options						
2	Preferred option: Transformer by 2025	$5.12	-	$3.95	$5.12	$0.03	108
3	2 year deferral out of period (2027)	$5.16	-	$3.66	$5.52	$0.00	138
	Non-network options						
4	Embedded generation	$10.72	$0.1	$9.77	$14.29	$0.14	108
5	Energy storage (battery)	$85.79	$0.1	$66.68	$99.15	$0.16	108
	Hybrid Network/Non-network options						
6	Demand response and network support contracted from an aggregator from 2021 and 3rd transformer deferred to 2026	$5.87	$0.11	$4.77	$7.10	$0.15	129

Notes:

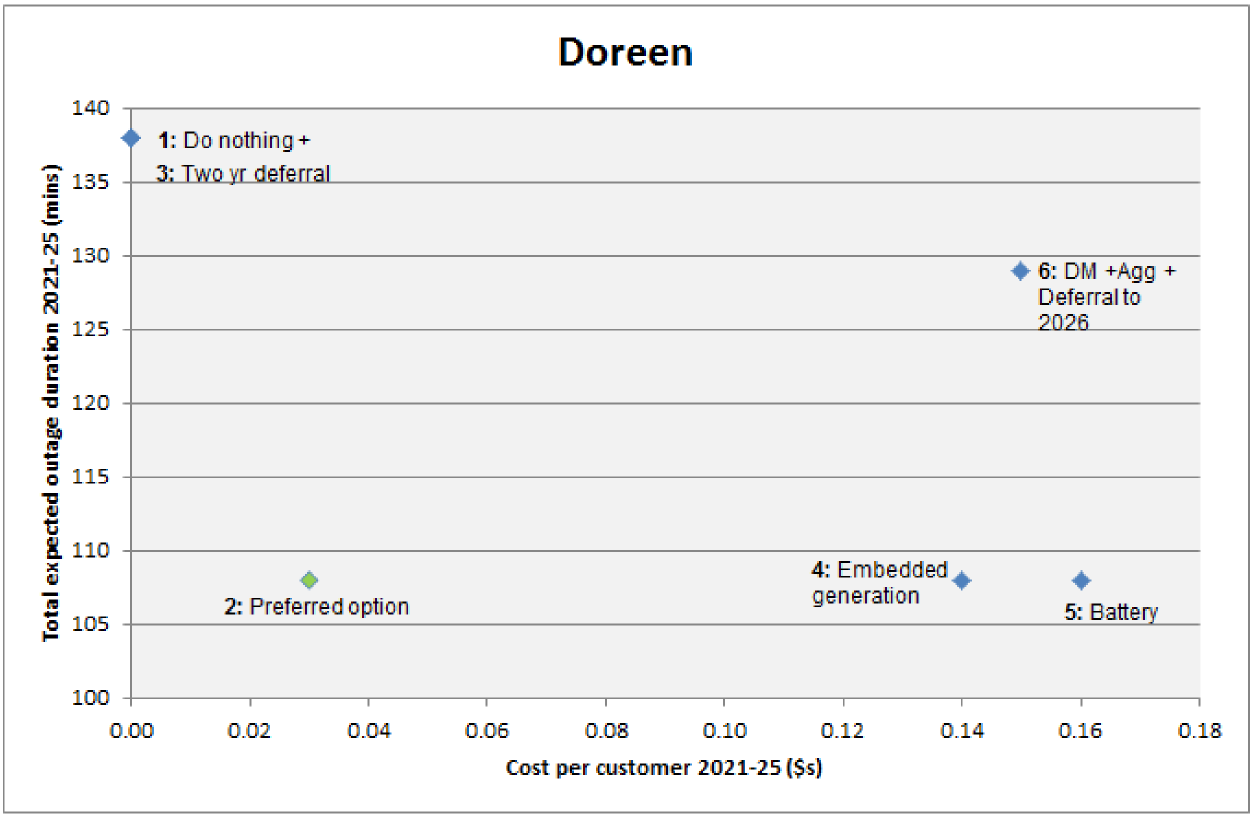
1. The PV of cost over the 50 year asset life represents the revenue associated with the projects (i.e. opex and return on and return of capital), in present value terms.
2. The average annual cost per customer represents the revenue associated with the projects (i.e. opex and return on and return of capital) and is an annual average over 2021-25.
3. The final column shows the expected outage duration over the 5 year regulatory period due to an inability to meet demand in the event of a transformer failure. It is calculated by multiplying the number of minutes that the station would not be able to meet the demand in the event of a transformer failure by the probability of a transformer failure (assuming no load cycling between feeders) and average transformer outage duration. The number of customer that would be impacted by the outage would depend on how the outage is managed in practice.

The current level of supply reliability associated with the equipment at Doreen is consistent with the preferred option (Option 2), i.e. 14 minutes in 2018.

Short Term

Figure 12 plots the cost and reliability impact for customers during 2021-25. Note that the cost impact affects all customers, while the reliability impacts are only experienced by the 27,970 customers (96% residential) connected to Doreen zone substation.

Figure 12: Price reliability trade-off – Doreen - Short term cost



The figure shows that:

- The best reliability outcome is achieved by installing the 3rd transformer by 2025 (Option 2). This is the preferred option;
- Within the 2021-25 period, the outcomes for the do nothing (Option 1) and two-year deferral (Option 3) are the same, with significantly worse reliability outcomes;

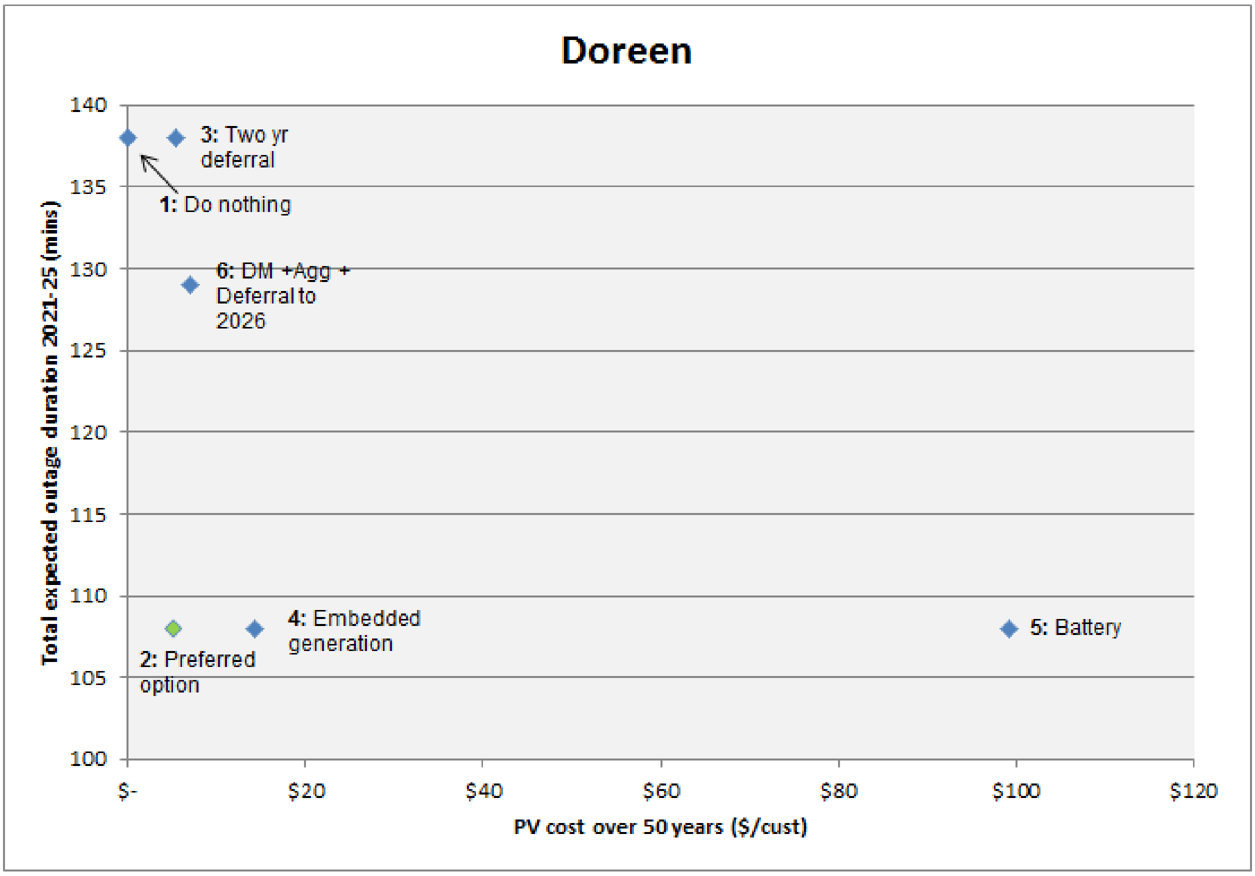
- The non-network options have either far higher short term cost impacts (Options 4, 5 and 6), or far worse reliability impacts (Option 6).

Long Term

Figure 13 plots the long-term cost (revenue associated with the projects in present value terms) and reliability impact for customers during 2021-25 of the various options for Doreen. This shows that:

- Over the long term, Option 2 (the preferred option) is the lowest cost to customers and equal first (with Options 4 and 5) for reliability;
- The two year deferral (Option 3) has a very similar cost to customers over the long term as Option 2 (the preferred option), but is far worse for reliability;
- Non-network options are either have far higher long-term cost impacts (Options 4 and 5) or far worse reliability impacts (Option 6).

Figure 13: Price reliability trade-off – Doreen - Long term cost



3. Customer research

Two areas of relevant customer research are provided below. The first is research concerning customer's price-reliability preference. The second is similar research that is specific to customers located in the Clyde North and Doreen growth corridors, where the augmentation projects are located.

Customer's preferences concerning price-reliability trade-offs

Augmentation expenditure: major projects

The following table summarises key messages from the customer research concerning customer's preferences on price-reliability trade-offs.

The research shows strong concern about affordability, but also that provision of reliable supply is strongly valued, particularly by small to medium businesses.

Table 7: Customer research insights

Small to Medium Businesses (AusNet Services' Survey)	Households (RMIT Survey)
Price/affordability • The issue of electricity affordability as a result of recent and significant prices increases was voiced as a major, if not the most salient, concern for all stakeholders. **Reliability** • Reliability is a priority concern for small to medium businesses.	**Price/affordability** • Nearly all households were concerned about electricity price rises and current costs. **Reliability** • The residential customers interviewed were satisfied with the current reliability of their electricity supply.
Residential and SME (Quantum Survey)	**Residential and SME (New Gate Research)**
Price/affordability • Around two-thirds of customers (67% residential and 64% SME) felt that their electricity bills have increased over the last 2 years. • More than a quarter feel that they have increased a lot (35% residential, 28% SME) • 31% of residential and 23% of SME consider that their electricity provided poor or very poor affordability. **Reliability** • An annual outage was considered acceptable by 63% of residential customers, but more frequent outages acceptable to only 31% of residential customers • For small to medium businesses, even an annual blackout was considered unacceptable by 38% of customers	**Price/affordability** • Costs and prices were "top of mind"; 37% rate value for money at 4 or less out of 10 • Providing a reliable, continuous supply was the most highly valued service. While the majority felt that supply was quite reliable, (58% rated this at 7+ out of 10), a fairly large portion, around one in five (22%) gave a low rating of 4 or less. **Reliability** • Most participants had a high level of tolerance for outages as long as they were well informed.

Additional localised customer research

Further telephone survey work has been undertaken in recent weeks to determine the views of customers in Clyde North and Doreen. To date, approximately 100 customers have been surveyed by Field Works in each location.

Key findings show that the majority of surveyed customers support investment to maintain reliability and a willingness to participate in shorter term demand management schemes:

Augmentation expenditure: major projects

- Almost all customers in both Clyde North (94%) and Doreen (87%) believe it to be very important that current reliability is maintained. No respondents reported this as being unimportant.
- Almost all customers in Clyde North (92%) and Doreen (90%) believe that AusNet Services should be addressing reliability issues in the next 5–7 years.
- The majority of customers in Clyde North (90%) and Doreen (92%) would be unhappy if AusNet Services did nothing to address reliability issues.
- Most customers (Clyde North, 73%; Doreen, 78%) would be willing to pay an additional cost to reduce their risk of an outage.
- There is a general consensus among customers in Clyde North (74%) and Doreen (75%) that it is fair to charge all AusNet Services customers an additional charge to avoid the risk of outages.
- Some verbatim reasons for the above answer:
    - 'It's such a minimum amount it's not going to break the bank.'
    - 'We have all got to chip in somehow and work together.'
    - 'It's a small amount and if it's going to mean that there are aren't the power shortages then it's worthwhile.'
- A greater proportion of Customer in both Clyde North and Doreen seem show a greater level of support for demand management projects in the short term (1 – 2 years) as opposed to the long term (3 – 7 years)
- A greater proportion of customers in Doreen (57%) indicated that they had heard of incentives offered to reduce usage during peak times compared to customers in Clyde North (40%).
- Many customers in Doreen stated that they would participate in demand management simply to reduce the risk of blackouts in their community (77%). This sentiment was slightly stronger among customers in Clyde north (73%).

Augmentation expenditure: major projects

Attachment: Transformer outages

This attachment provides information about our experience with transformer outages and how these are managed in practice. Specific questions raised by the Customer Forum in relation to the original negotiating note were:

1. What is the realistic risk of transformer failure?
2. Would a transformer be out of service for 9 months? Do we have spares?
3. Have we had a 9 month transformer outage in practice?
4. What is the number of transformer outages as a proportion of the transformer fleet.

1 Realistic risk of transformer failure?

In most years there is at least one transformer failure (even with a replacement program).

2 Would a transformer be out of service for 9 months? Do we have spares?

Outage period

Any internal problem with a power transformer requires lengthy outages even for repairs. The actual outage duration is dependent on the specific design of transformer, the failure mode and location, and site accessibility if a spare replacement is required.

Spares

The Central and East region have 120 power transformers and two spares. The North region has 28 transformers and one spare. The probability of a spare transformer being available is factored into the economic modelling. [2]

It usually takes at least a month to install a spare transformer, longer if any modifications need to be made to the foundation to accommodate the transformer. Therefore the replacement time will usually be less than 9 months.

Delivery time for new transformer

In the event a spare transformer is not available, the nine month delivery period indicated in the negotiating position note is realistic. In practice the delivery time can often be longer than nine months. Additional time is typically needed up front for the transformer design and procurement and after delivery for installation and testing.

As transformers are designed and manufactured to an order the delivery time will depend on how busy the manufacturer is with other orders. Transformer manufacturers are also dependent on component suppliers.

Our most recent order for standard 20/33MVA power transformer for the new Morwell zone substation has taken more than a year (the third example in the box below). Additional examples of actual delivery times are provided below.

[2] For example, based on 120 power transformers in the Central and East regions, two spares, the average failure rate based on the transformer condition and a provisioning time of 9 months for a spare, the probability of a spare being available is 0.84.

Examples of transformer delivery times

PS ZSS : 35 MVA, 66/11 kV, OCTS, ONAN

This transformer is an electrical repeat of a unit supplied in 2015, but with an updated specification. The contract was signed on 15 June 2018 and delivery to site is expected 10 April 2019. That is just short of 10 months which excludes the tender process which normally takes about 3 months.

MWE ZSS : 10 MVA, 66/6.6 kV, OCTS, ONAN

The contract has a commencement date of 20 Oct 2017 and the unit was ready for delivery to site on 28 June 2018. This is 8 months after contract commencement which excludes the tender process which normally takes about 3 months and the site installation, testing and commissioning which could be 1 month. This is also a smaller unit with that does not have an on load tap changer. Tap changers are normally the longest lead time components for transformers and their delivery is often 6 months.

MWL ZSS: 33 MVA, 66/22 kV, OLTC, ODAF

This unit is more representative of our zone substation fleet. The contract commencement was 31 Oct 2017 and the initial promised delivery was 3 May 2018. However, delivery has been delayed to 2 Oct 2018. This transformer will be delivered 11 months after contract commencement and will only be ready for service in 12 months. Add the tender process to this and the transformer will be ready for service 15 months from when the decision was made that this transformer was required.

In the case of an emergency, there are some actions that can be taken to reduce the time between ordering and commissioning such as by:

- approaching a single supplier though this would typically increase the cost
- paying for fast tracking (cost of between 25% to 50% of the transformer price)
- supply our own bushings – however we then carry the risk of bushing failure for testing as well as the warranty period.

How is the outage managed for customers

Transformer failures result in some customer outages until the field operations/first response gets to the site to isolate the faulty transformer.

In circumstances where there is a lengthy outage of a transformer, in most cases load can still be supplied as it remains under the transformer rating. However, there is a much higher customer risk if another transformer at site was to develop a problem.

Other solutions that have been used to maintain supply are load transfers (where this is possible) and embedded diesel generators placed on the network during the extended outage.

3 Have we had a 9 month transformer outage in practice?

No.

4. Number of transformer outages as a proportion of the transformer fleet?

Information on major zone substation and terminal station transformer outages in recent years is provided below. As noted above, across our three service regions we have 148 power transformers. Of the examples at zone substations, the longest outage was at Doreen.

Table 8: Zone substation transformer outages

Zone Sub	Trans No.	Date	Failure	Response	Time to return to Service (Days)
Ringwood North	No 3	29/01/2014	Internal Flashover	Replace Transformer with Spare , held on site	19
Doreen	No 2	14/03/2017	Internal Flashover	Repair HV Bushing lead inside tank	63
Bayswater	No 2	6/09/2017	Overheating connection	Repair connection	6
Wonthaggi	No 3	19/01/2018	Bushing failure	Replace 66kV Bushings	15

Table 9: Terminal station transformer outages

Terminal Station	Trans No.	Date	Failure	Response	Time to return to Service (Days)
BATS	B1	1/07/2016	Internal Flashover	Replace Transformer with Spare	21
FBTS	B1	17/11/2016	Internal Flashover	Replace Transformer with Spare	35
SMTS	F2	x/11/2017	Tap changer investigation	Repair of tap changer	27
SMTS	H1	18/06/2018	Tap changer investigation	Repair of tap changer	14