AusNet Electricity Services Pty Ltd

Electricity Distribution Price Review 2022-26

Part III

Submitted: 31 January 2020

About AusNet Services

AusNet Services owns and operates key regulated electricity transmission and electricity and gas distribution assets located in Victoria, Australia. These assets include:

- A 6,685 kilometre electricity transmission network that services all electricity consumers across Victoria;
- An electricity distribution network delivering electricity to approximately 737,000 customer connection points in an area of more than 80,000 square kilometres of eastern Victoria; and
- A gas distribution network delivering gas to approximately 710,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

AusNet Services' vision is to create energising futures by delivering value to our customers, communities and partners.

For more information visit: www.ausnetservices.com.au

Contact

This document is the responsibility of the Regulated Energy Services division of AusNet Services. Please contact the indicated owner of the document below with any inquiries.

Charlotte Eddy
Manager Economic Regulation
AusNet Services
Level 31, 2 Southbank Boulevard
Melbourne Victoria 3006
Tel: (03) 9695 6000

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6 Network characteristics

6.1 Key points

- We operate and manage one of the two rural distribution networks in Victoria.
- Split by the Great Dividing Range, our network spans from the northern and eastern suburbs of Melbourne eastward to Mallacoota, and north to the Murray River. It covers heavily forested and mountainous areas, as well as the low lying and coastal regions of Gippsland. This area includes alpine regions, rural areas, high growth suburbs of Melbourne, coastal areas and forested areas with few customers.
- Low customer density, difficult terrain and obligations to manage extreme bushfire risk makes it comparatively expensive to serve our customers. Despite these challenges, we have recently delivered record reliability performance and are cost efficient.
- Bushfire risk in our service area is among the highest in the world[1], with the potential for catastrophic losses to life and property as seen during the current bushfire emergency impacting on large parts of our network. In accordance with the obligations determined by the Victorian Government, we have made significant investments in mitigating bushfire risk. At present this involves investment in Rapid Earth Fault Current Limiter (REFCL) technology. We also undertake more frequent asset inspections and vegetation management than interstate electricity distribution network service providers (DNSPs) in accordance with Victoria's bushfire regulations.
- The Australian Energy Regulator's (AER) annual benchmarking reports do not currently account for safety expenditure, which differs markedly across distributors due to difference in their regulatory obligations. As a result, the AER's rankings of DNSP performance disadvantages those companies, such as AusNet Services, that operate in particularly severe bushfire prone areas. It is important that further work is undertaken to address this issue.
- Our network has the highest proportion of residential customers among the distribution businesses in the National Electricity Market (NEM). As a result, our network must be capable of meeting the peaks and troughs of residential demand each day (noting that commercial and industrial demand is more constant over the course of the day). In addition, a higher proportion of residential customers have installed rooftop solar than commercial and industrial customers (though this may change in the future). This means that the impact of solar uptake is amplified on our network.
- Reflecting these trends, the data shows that peak demand on our network is continuing to grow, while energy consumption has declined. These trends are important factors in developing our forecasts for the 2022-26 regulatory period.

6.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 6.3 provides key statistics regarding our network and the typical volume of our annual maintenance and renewal activities;
- Section 6.4 discusses the physical and environmental challenges in our network area including harsh terrain, low customer density and significant bushfire and flooding risk. These

[1] Blong, R., Sinai, D., & Packham, C. (2000). Natural Perils in Australia and New Zealand. Melbourne, Australia: Swiss Re Australia.

factors impact our capital and operating costs and highlight the importance of taking account of relevant operating environment measures in cost benchmarking;

- Section 6.5 provides information on solar penetration in our network; and
- Section 6.6 provides information on customer demographics and trends in network usage.

6.3 Key network statistics

We provide distribution services to approximately 737,000 customers. Around 90% of our customers are households and around 60% of our customers are in rural areas.

The electricity network comprises a 'sub-transmission' network that consists of predominantly overhead lines that operate at 66 kV, with zone substations transforming the voltage and providing the feeder exit points for the 'distribution' network, which generally operates at a voltage of 22 kV and consists mainly of overhead lines but also includes underground cables. Some customers in remote and low population density rural areas are supplied by Single Wire Earth Return (SWER) Medium Voltage (12.7 kV) distribution networks. Most of our customers are supplied at low voltage from distribution substations on the 22 kV network.

Our distribution system includes:

- 62 zone substations;
- 61,000 distribution substations;
- 420,000 power poles; and
- 46,400 kilometers of underground cable and overhead lines.

Each year our renewal and maintenance activities typically include approximately:

- 115,000 poles and pole tops being inspected;
- 3,000 poles being replaced;
- 4,000 cross-arms being replaced;
- 220 km overhead conductors being replaced; and
- 35,000 streetlights being replaced.

A key change for the operation of the distribution network is the increasing penetration and impact of distributed energy resources, particularly rooftop solar.

Our expenditure requirements are unavoidably affected by the physical and environmental attributes of our service area, which are discussed in the next section.

6.4 Physical and environmental characteristics

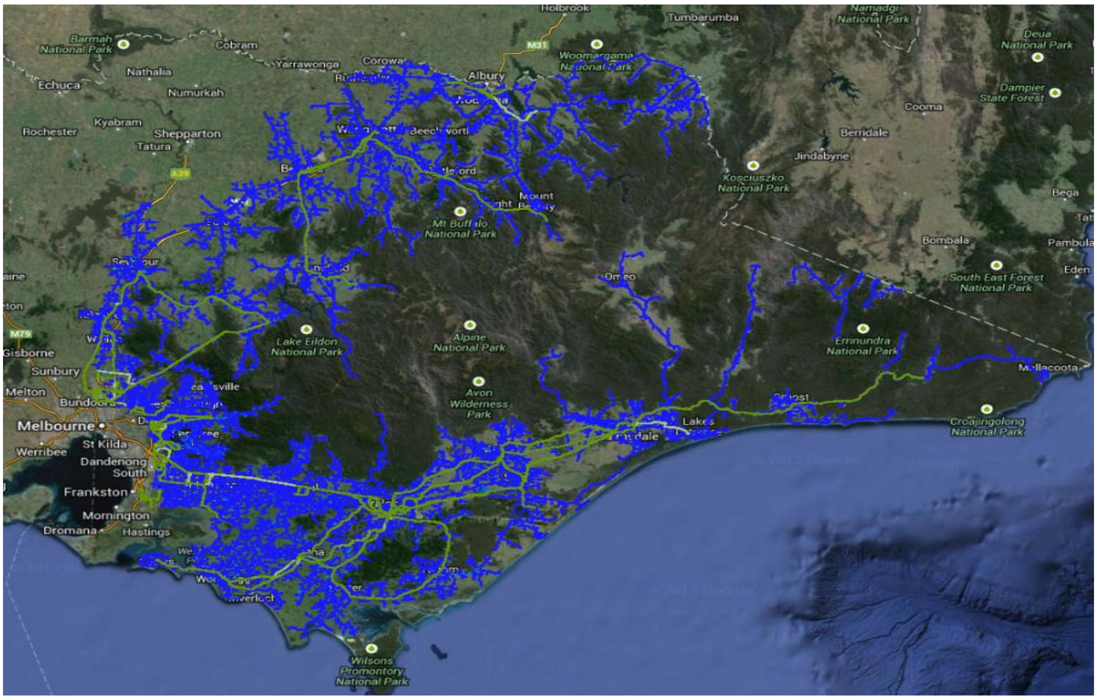
Our network has several physical and environmental characteristics that pose significant challenges to reliable service provision and impose higher costs on our business than on networks without these characteristics. These characteristics include:

- the physical separation of the network by the Great Dividing Range and associated harsh terrain;
- a rural network with resulting low customer density; and
- climate, terrain and vegetation that contribute to a high risk of bushfire and floods.

6.4.1 Physical separation of network and harsh terrain

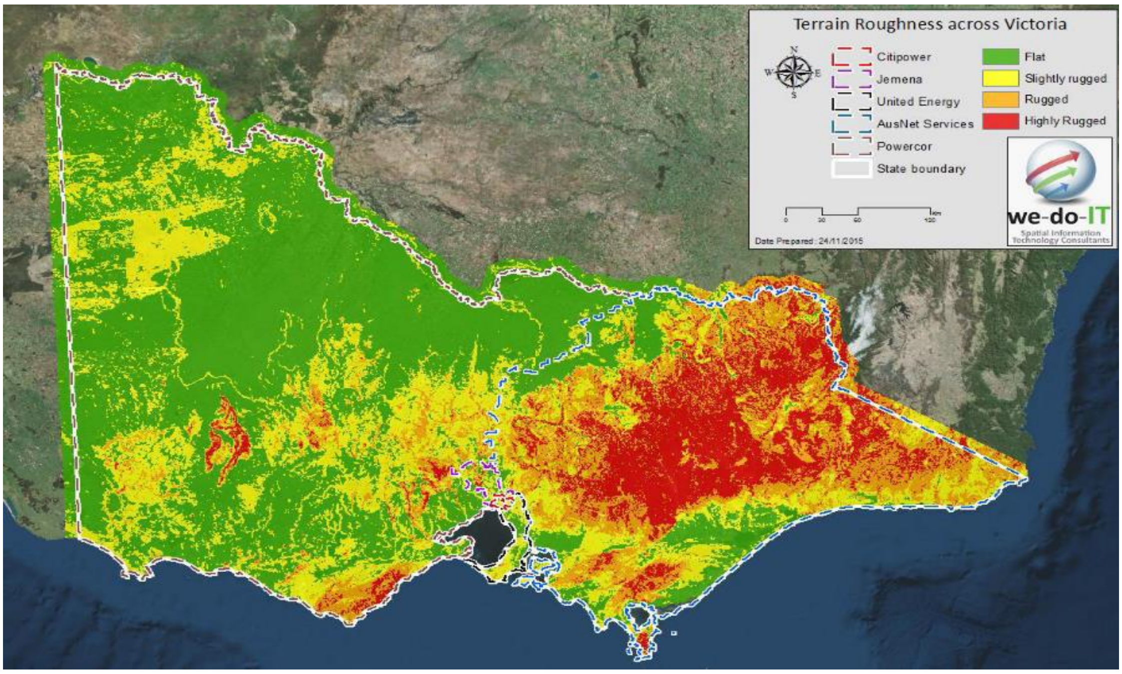
The footprint of our network is physically separated by the Great Dividing Range. Given this topography, we operate two service delivery regions, the East Region and North Region. This ensures our regional centres are appropriately resourced and that we can address challenges in an expedient manner. Consequently, our service centres tend to have lower levels of resource utilisation than other rural networks. In addition, our service teams operate across service areas that are affected by difficult terrain, as illustrated in the figures below.

Figure 6-1: AusNet Services' distribution network separated by the Great Dividing Range



Source: AusNet Services.

Figure 6-2: Harsh terrain affects network operations



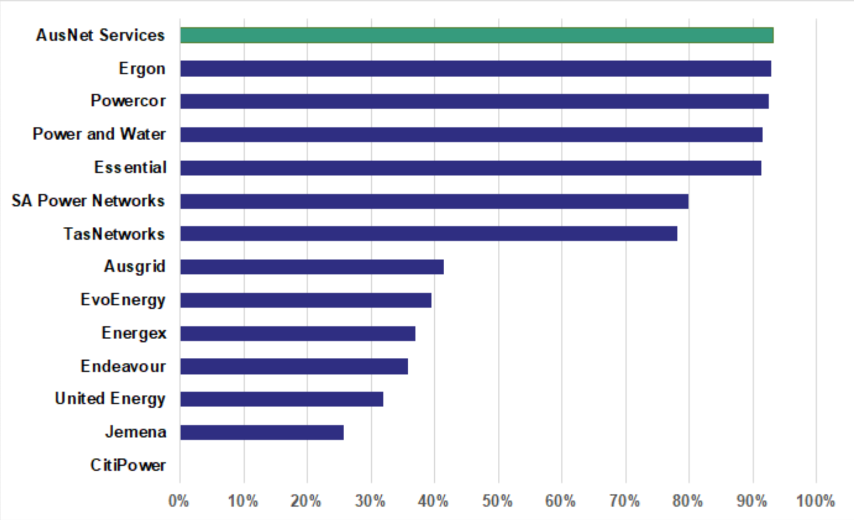
Source: AusNet Services.

6.4.2 Rural network with low customer density

The rural nature and physical characteristics of the topology of our network area also mean that we have low customer density compared to other DNSPs.

As shown below, over 90% of our network (by line length km) is in rural areas. More than 80% of this is in high bushfire risk areas (HBRA).

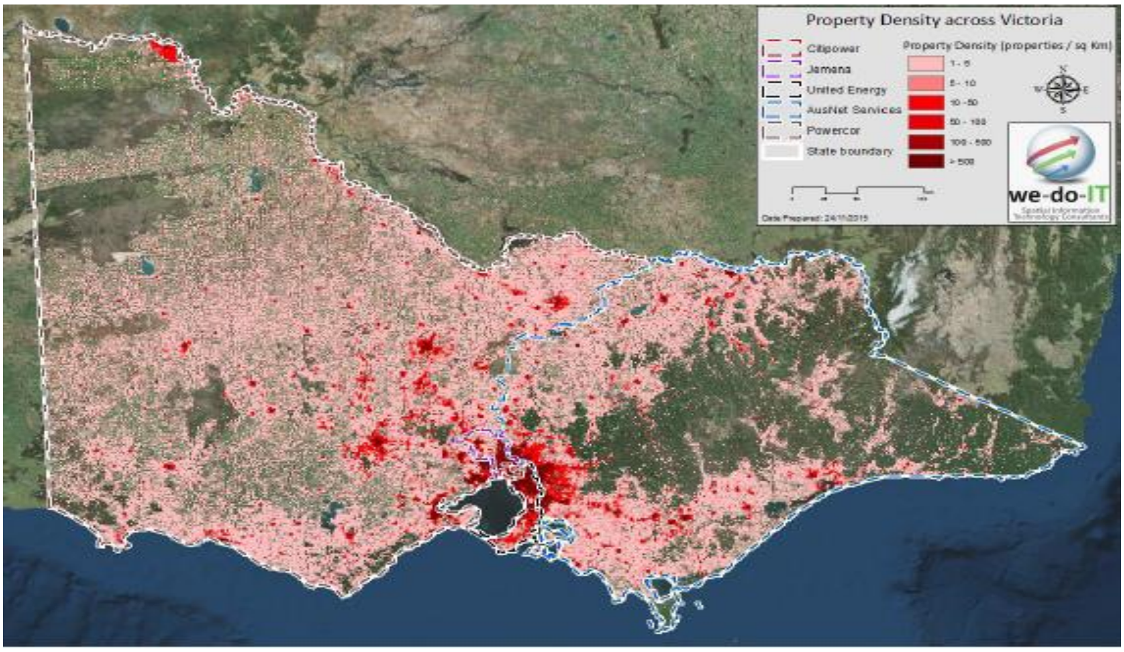
Figure 6-3: Proportion of network in rural area (km line length) in 2018



Source: Electricity Benchmarking RINs, 3.7 Operating Environment Terrain Factor Rural Proportion %.

The figure below shows that our service area has much lower customer density than our Victorian peers and results in a higher costs per customer, as noted by the AER.

Figure 6-4: Low population density



Source: AusNet Services.

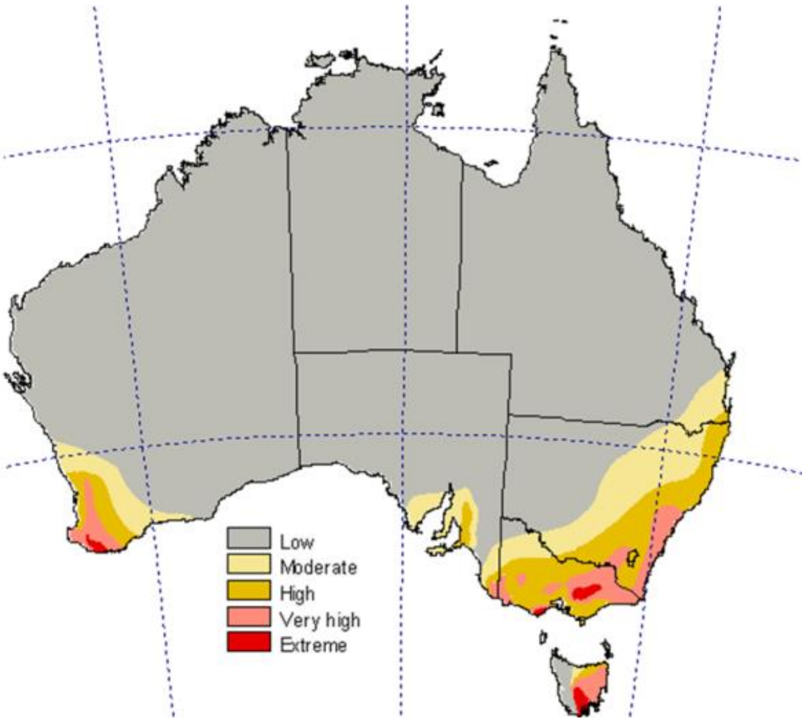
A large proportion of feeders supply low density customer areas, which is defined as lot sizes exceeding 2000 square meters (m^2). Furthermore, 29% of our distribution feeders have less than 10 customers for each km of line length.

6.4.3 High bushfire risk

The climate, terrain and vegetation of eastern Victoria contribute to the region's high level of bushfire risk. Accordingly, our service area is exposed to a particularly high level of bushfire risk, as evidenced by recent bushfire activity in our network area (including Gippsland and Alpine regions) and the catastrophic 2009 Black Saturday bushfires.

The figure below shows the high level of bushfire risk in eastern Victoria relative to other jurisdictions. The level of bushfire risk is defined as, for a given ignition source, the likelihood of a bushfire developing multiplied by the consequence of a bushfire in that area.

Figure 6-5: Bushfire risk in Australia



Source: Blong, R., Sinai, D., & Packham, C. (2000). Natural Perils in Australia and New Zealand. Melbourne, Australia: Swiss Re Australia.

Substantial communities are settled within eastern Victoria, including in areas where there is an 'extreme' level of bushfire risk. As a result, our service area is one of the world's worst areas for bushfires with the potential to cause catastrophic losses to life and property.

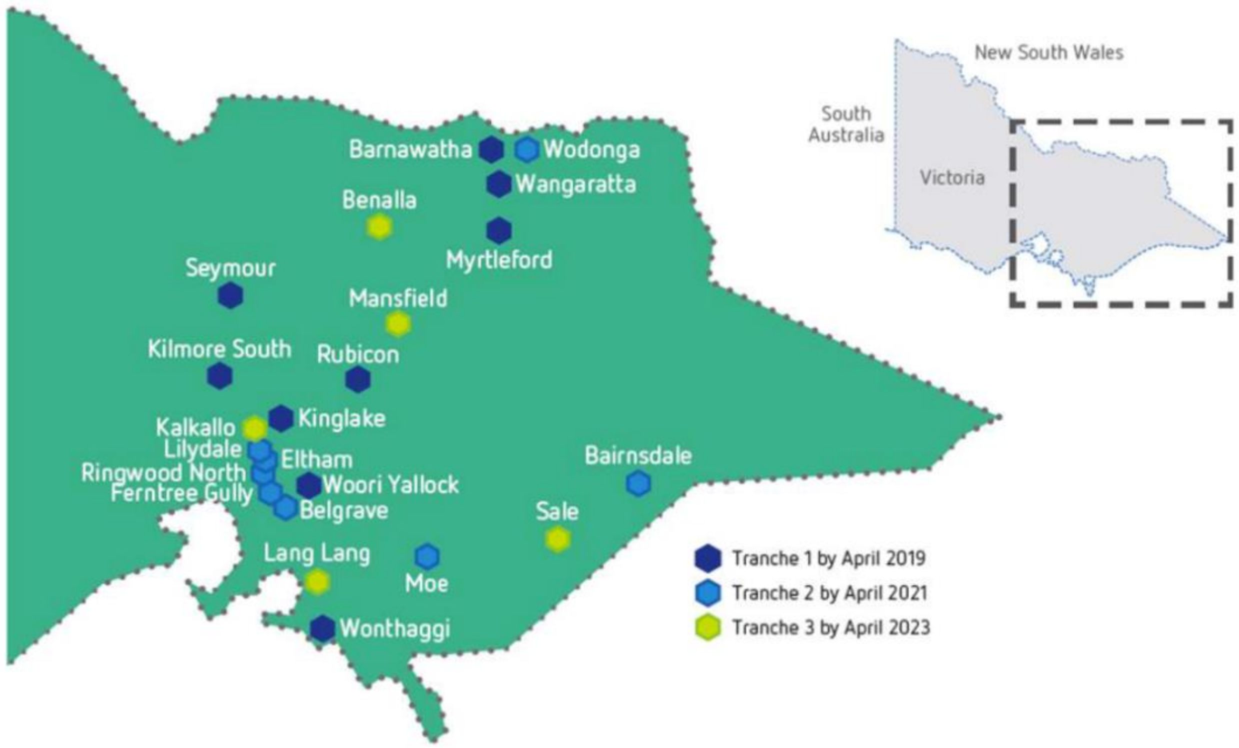
Our policy is to implement a bushfire mitigation management strategy that complies with legislative requirements and creates a harmonious balance for community safety, preservation of the environment and cost effectiveness. Specifically, we aim to:

- minimise the risk, to as low as reasonably practicable, of fire ignitions by our distribution network assets that could become a wildfire and threaten public safety and property;
- meet the requirements of the Electricity Safety Act 1998, all relevant regulations and the Victorian Electricity Distribution Code;
- regularly review and develop management programs, processes, practices, methods and implement efficiencies for the benefit of customers and other stakeholders;
- minimise the frequency and length of disruptions to the general public;
- be committed to the safety of the community and employees engaged in the provision of services;
- preserve and enhance the environment; and
- raise awareness of all aspects of bushfire mitigation through increased communication.

In 2016, bushfire mitigation regulations were introduced that require us to meet new performance standards for lines originating from 22 selected zone substations. The installation of REFCL is the only technically feasible solution capable of meeting the specified performance requirements. This electrical protection technology is designed to minimise the fault current (energy) dissipated from phase to earth (wire to ground) faults on the 22 kV network to reduce the risk of fire ignition associated with network incidents.

The REFCL program is being implemented in three tranches, with the third tranche completed in April 2023, as shown in the figure below.

Figure 6-6: REFCL program



Source: AusNet Services.

In addition to delivering the REFCL program, bushfire risk in our service area is mitigated through our asset inspection and vegetation management programs. For example, we have approximately 210,000 poles in areas designated as hazardous bushfire risk. Inspection of these assets occurs at intervals of less than 37 months through a combination of ground (test and inspection) and an aerial-based inspection cycles.

Vegetation clearances adjacent to overhead powerlines are managed in accordance with the Electricity Safety (Electric Line Clearance) Regulations. In addition, our Vegetation Management Plan is provided annually to Energy Safe Victoria for its review and acceptance. This plan includes procedures for the cyclic inspection, customer notification and consultation and the pruning and removal of vegetation to maintain the prescribed clearance spaces. Each year, approximately 268,000 powerline spans are inspected for vegetation and 5,000 hazardous trees are removed.

6.4.4 Flooding risk

Our distribution network is in areas where the average annual rainfall ranges from 600 millimeters (mm) to 1,200 mm. Some parts of the network in the Northern and Eastern regions are also affected by flooding hazards. For example, approximately 35% of all network feeders have some parts in flood hazardous areas. Furthermore, around two-thirds of the distribution network is in areas designated as ‘bushfire prone’.

6.4.5 Operating environment needs to be accounted for in cost benchmarking

The highly rural nature of our network and the bushfire safety regulatory obligations we must comply with need to be considered when comparing our expenditure against other DNSPs. The

AER has recognised that cost comparisons between networks must be conducted with caution as costs are unavoidably affected by the inherent characteristics of each network:

> *… on a 'per customer' metric, large rural DNSPs will perform poorly relative to DNSPs in suburban and metropolitan areas. Typically, the longer and sparser a DNSP's network, the more assets it must operate and maintain per customer. The 'per MW' metric exhibits a similar pattern. Conversely, on 'per km' metrics, large rural DNSPs will perform better because their costs are spread over a longer network.*[2]

Evidently, the costs of delivering safe and reliable distribution services are substantially higher in service areas affected by bushfire risk. Unfortunately, the AER's benchmarking analysis does not yet account for the impact of safety expenditure on productivity performance appropriately because it:

- treats all vegetation management and inspection-driven costs as an input; and
- it does not capture safety as an output.

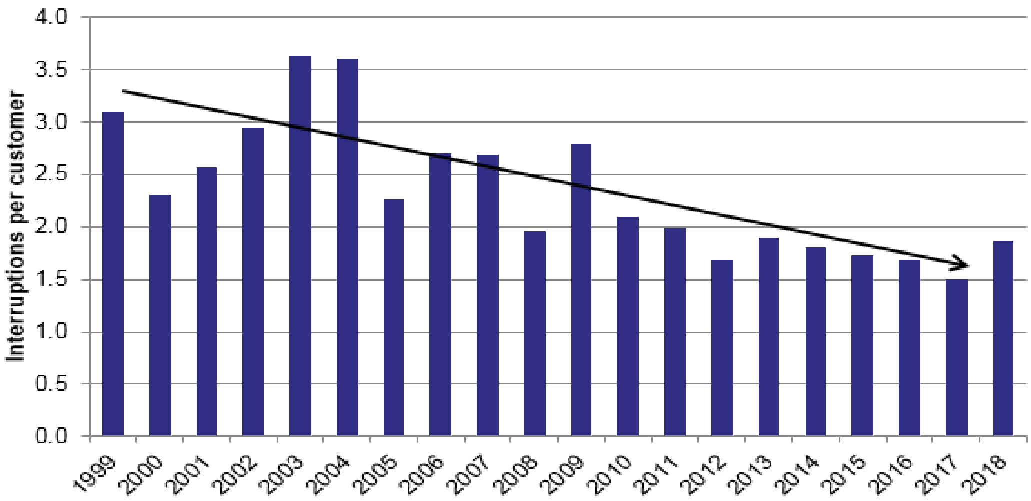
In the absence of techniques that account for safety expenditure appropriately, the AER's benchmarking results will understate our productivity performance compared to other network companies with less challenging operating environments. We have previously raised this issue with the AER[3] as we are concerned that the company rankings presented in its annual benchmarking report do not accurately reflect relative performance.

Nevertheless, we are the lowest opex cost rural distributor in Australia as measured by opex per customer (which is a closer reflection of the actual amount on the bill rather than the modified opex comparisons used in the benchmarking). In addition to our on-going efforts to drive efficiency savings, this outcome reflects the impact of our 'cost-out' program which commenced in 2017. Further information on this program is in Chapter 10.

6.4.6 Maintaining strong reliability performance in the face of challenges

Despite the inherent challenges associated with our service area, our performance has improved over time and we achieved record reliability in 2017 (see figure below). While relatively mild weather contributed to that outcome, it also reflects the significant effort we have put into providing a reliable network service.

Figure 6-7: Driving reliability improvements (1999 – 2018)



Source: AusNet Services.

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2 AER, Annual benchmarking report, Electricity distribution network service providers, November 2018, p. 34.

3 Letter from Tom Hallam to Evan Lutton, Re: Draft AER Benchmarking Reports, 17 October 2018.

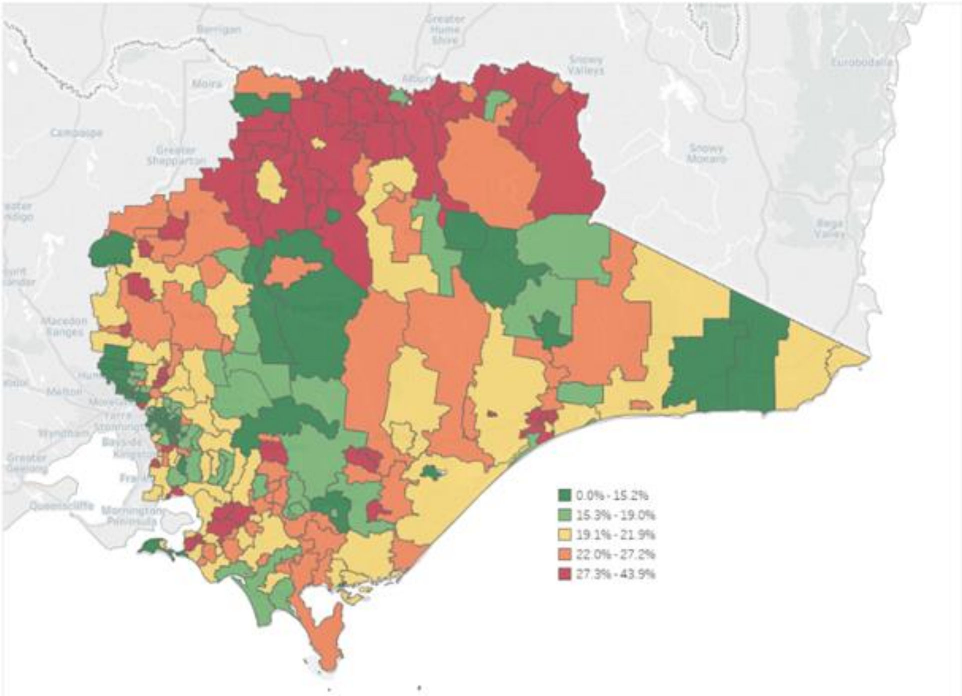
Note: Total number of unplanned interruptions per customer (excluding major storm events).

6.5 Solar penetration

Over 140,000 of our customers already have solar installations and we forecast that this number is forecast to be around 225,500 by 2026, an increase of around 60%. Also, with the size of solar systems getting larger, the solar energy produced is forecast to double in size.

The figure below shows that the level of solar penetration varies across our network. However, there are areas of our network with solar penetration greater than 27% (the red areas in the figure below), which is as high as areas in South Australia and Queensland.

Figure 6-8: Residential solar penetration by postcode



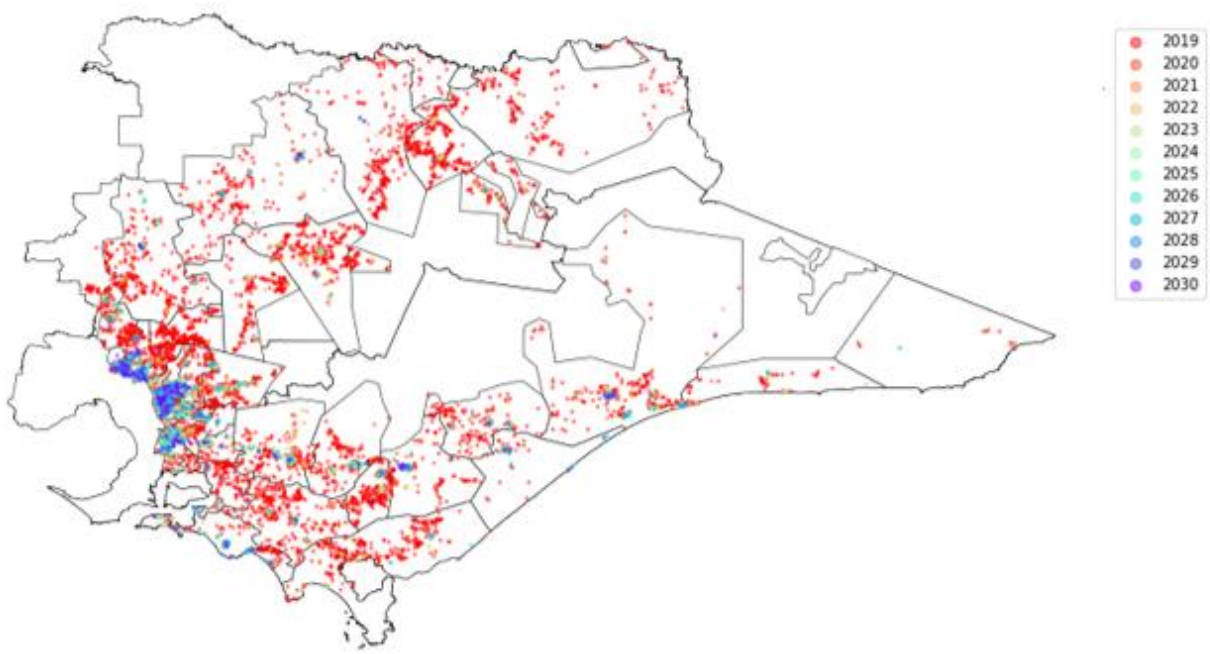
Source: AusNet Services.

This increase in the size and quantity of solar is creating some challenges on our network. For example, voltage rises, if not managed, can damage customers' appliances (for solar and non-solar customers). High voltage can also cause solar systems to shut off. One way of managing this problem is to prevent customers from connecting solar to the network or exporting their solar energy onto the network. However, neither of these solutions is acceptable to customers.[4]

The figure below shows the location of existing constraints and future emerging constraints. This shows that the limitations are relatively evenly spread across the rural and urban parts of the network. Weaker parts of the network are currently experiencing constraints, but 'stronger' areas will increasingly be impacted.

4 This lack or loss of control is a particularly important issue for our customers and is discussed in more detail in Chapter 9.

Figure 6-9: Forecast distribution substation limitations



Source: AusNet Services.

As outlined in Chapter 9, our proposal outlines a way to allow more solar to be added to a network at an acceptable cost. This modest investment will also:

- reduce the voltage problems that would be experienced by many of our customers;
- reduce wholesale electricity costs for all customers; and
- reduce carbon and air pollution.

6.6 Customer demographics and trends

Residential customers account for around 90% of our customer base, which is the highest proportion in the NEM. As noted earlier, this means that the pattern of demand is relatively less constant, varying more over the course of the day and experiencing significant peaks when in the early evening when households need to use the most electricity. In addition, it is the residential customers that have been investing most in rooftop solar.

As previously explained, the electricity industry in Australia is undergoing significant transformation, driven by changes in customer preferences and technology advancements in renewable and distributed energy resources. These changes are enabling customers and their agents to participate in energy services and markets in an unprecedented manner.

As our customer base is dominated by residential customers, the impact of these changes is amplified on our network. For example, energy consumption per customer has declined in recent years as a result of improvements in energy efficiency and the increasing penetration of solar photovoltaics (PVs). In contrast, peak demand has continued to increase in response to population growth and increasing air conditioning load.

In the next chapter, we examine how the recent trends in our customers' network usage are expected to drive our peak demand and energy consumption over the 2022-26 regulatory period.

7 Demand and energy forecasts

7.1 Key points

- Accurate customer numbers and maximum demand forecasts are essential to prudently and efficiently meet our customer's needs in a dynamic and ever-changing environment. The forecasts also underpin operating expenditure and major growth capital expenditure (augex) expenditure proposals that have been negotiated and agreed with the Customer Forum.
- Our customer base is forecast to grow steadily by around 1.8% per annum, in line with the Victorian Government's 2016 Victoria in Future planning document.
- Maximum demand is forecast to continue growing, albeit at a slower rate than recorded over the current regulatory period.
- Energy use from the network is expected to continue to fall, with declines in residential and commercial energy consumption per capita being driven by improvements in energy efficiency, the renewed growth of solar installations and other price-responsive changes in customer behaviour.
- We are carefully managing the uncertainty associated with new and emerging distributed energy resources (DER) and their subsequent impact on our network.

Table 7.1: Demand, energy and customer forecasts

	2021-22	2022-23	2023-24	2024-25	2025-26
Customer numbers	769,586	782,596	795,734	809,066	822,443
Energy consumption (GWh)	7,300	7,259	7,229	7,204	7,183
Maximum demand (MW)	2,016	2,043	2,071	2,098	2,125

7.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 7.3 describes the enhancements we have made to our forecasting capability during the current regulatory period;
- Section 7.4 explains our forecasting methodology for customer numbers and the historical and forecast data for residential, small / medium commercial and industrial customers;
- Section 7.5 explains our forecasting methodology for energy consumption and the historical and forecast data;
- Section 7.6 explains our forecasting methodology and data for maximum demand. A comparison with the Australian Energy Market Operator's (AEMO) forecasts is also provided;
- Section 7.7 explains how our forecasts satisfy the requirements in the Rules; and
- Section 7.8 sets out the supporting documents for the matters discussed in this chapter.

7.3 Enhanced forecasting capability

The role of the traditional network is being transformed as customers take up new technologies, such as rooftop solar generation, battery storage and, to a lesser degree, electric vehicles.

According to both Energy Networks Australia and the CSIRO, the pace of change will continue to increase over the next 10 years as customers adopt new technologies.[1] Consequently, accurate demand and energy forecasts are essential to prudently and efficiently meet our customers' needs in a dynamic and ever-changing environment. We have been required to improve our forecasting capability because the drivers of network utilisation are changing significantly.

Recognising this, we invested additional resources during the current regulatory period to improve our forecasting capability. That investment was essential notwithstanding the positive feedback received on our forecasting methodology from the Victorian Energy Consumer and User Alliance (VECUA) and the AER in the 2016-20 review process.[2] Our improved forecasting capability has also been supported by improved accuracy of consumption data provided by smart meters and the modernisation of key information and communication technology (ICT) platforms, which are now available to the forecasting team.

In broad terms, our forecasting approach is now more granular, and we can now better model the underlying drivers that affect movement in customer numbers, including energy consumption and maximum demand at various locations. This is essential as the new operating environment is one where customer behaviour is increasingly more adaptive and flexible due to continued growth in solar photovoltaics (PV) and battery storage.

Our forecasting capability now involves:

- A bottom-up granular approach utilising advanced metering infrastructure (AMI) data and analytics, as opposed to a top-down approach, which has delivered more detail involving:
    - temperature-energy correlations, which can now be calculated with a significantly higher degree of accuracy due to interval data;
    - energy profiles for houses of different ages, which illustrates the impact of energy efficiency technologies;
    - energy profiles for solar and non-solar customers, which allows us to quantify the impact of energy savings from solar installations and the impact of solar at periods of peak demand; and
    - the impact of different price structures on different customers;
- Customer loads being categorised by customer class which allows temperature impacts to be applied to residential customers only; and
- Maximum demand data being correlated to the cumulative temperatures preceding a maximum demand day, which has a stronger relationship with maximum demand than the peak temperature on that day.

We are also continually reviewing and refining our demand forecasting methodology to ensure it is incorporating current analytical models and techniques. Further detail on our forecasting methodologies for customer numbers, energy and maximum demand are provided in sections 7.4 to 7.6.

7.4 Customer number forecasts

7.4.1 Customer forecast methodology

Customer connection expenditure is the cost associated with connecting new customers to our network at the customer's request. The total forecast expenditure is the product of new customer volumes and connection cost unit rates. Thus, customer growth is a key input in forecasting connections-related capital expenditure (capex). Customer number forecasts also form the basis for

1 CSIRO and Energy Networks Australia April 2017, Electricity Network Transformation Roadmap: Final Report.

2 AER, Attachment 6 – Capital expenditure, AusNet Services Preliminary Decision 2016-20, p. 95.

both demand and energy forecasts, since the number of customers on the network is a key determinant of both demand and energy. Our residential customer forecasts are developed at the LV feeder for granularity and then zone substation level for aggregation.

We use an independent assessment of the projected growth in customers over the forecast horizon which is the Victorian Government's Victoria in Future (VIF) publication. The VIF report provides five-yearly snapshot forecasts of population and dwelling numbers for regions defined as Victoria in Future Small Areas (VIFSA). Since many dwellings are connected to our network, these dwelling projections can be used as a starting point for the growth in residential electricity customers.

Customer growth rates by zone substation are a key input into the demand forecasts. Given the importance of customer growth rates by zone substation, we have developed customised, in-house algorithms that predict a feeder's point in the growth cycle.

The VIFSA level forecasts can be approximately mapped to zone substation regions and then up and down to feeders and terminal stations. Below the zone substation level, feeders are also apportioned to the nearest VIFSA (or multiple VIFSAs) to derive forecast customer numbers. Particularly in growth corridors, we assume that feeders are extended over time with a consistent spread of geographic capture of each relevant VIFSA. This approach is considered adequate where the VIF projections are shown to be accurate.

Where there is evidence of VIF projections not reflecting actual growth, the VIF forecasts are adjusted to reflect our view of the likely growth. Any adjustment to a forecast that is made is based on recent trends and an assessment of local conditions. For example, by utilising the expert knowledge of network planners responsible for particular regions or other using information garnered from other sources, such as specific connection inquiries and/or information made available by housing developers and industry bodies.

Our internal analysis suggests that the approach to forecasting customer numbers is correctly predicting where network growth will occur. Since customer number forecasts are integral to maximum demand and capex planning, the improved accuracy of customer forecasts also improves the accuracy of these forecasts.

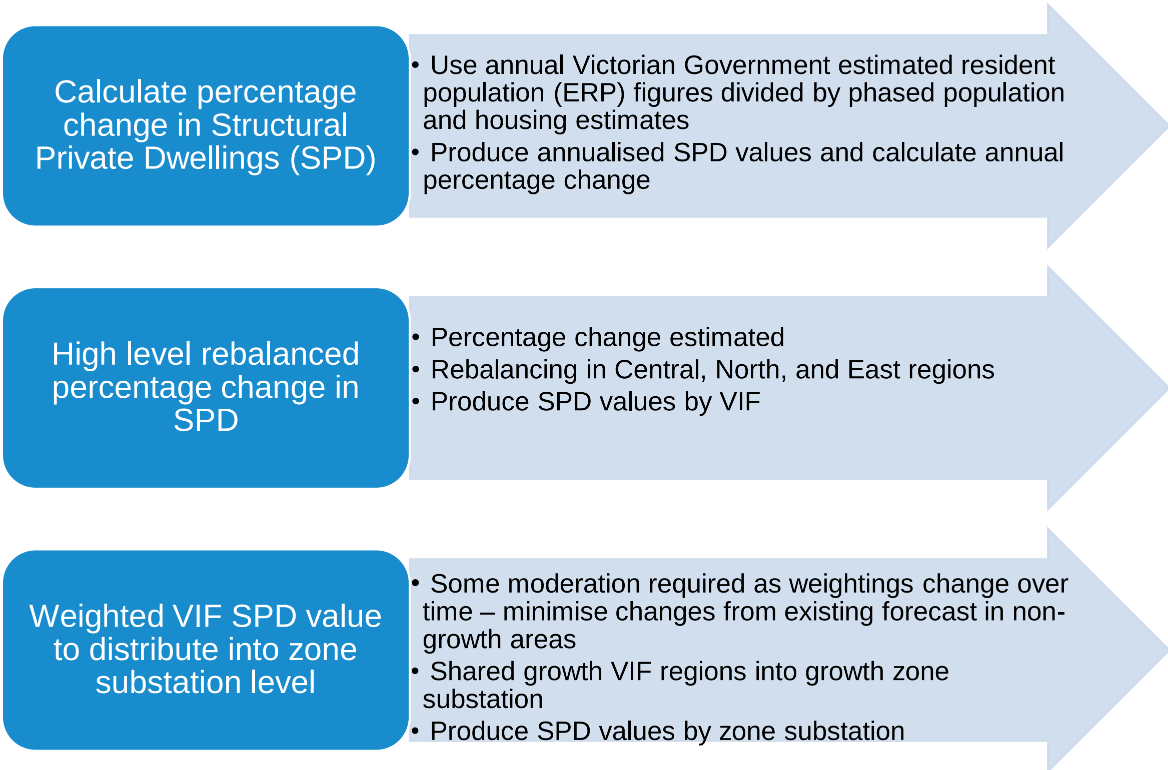
While the VIF publication is the primary data source for forecasting residential customers, it does not contain projections for commercial or industrial customers. As there is no dependable data source on which to base trends for these customers, we:

- determine the historical relationship factors between the residential base against each of the commercial and industrial bases; and
- apply these factors, as a constant, to the residential customer number growth rate to produce starting forecasts.

The general data trends available for larger commercial and industrial customers are then considered and we manually apply these to adjust the starting forecasts. This approach is adopted to improve accuracy because these customer types usually have more pronounced trends.

Figure 7-1 (below) shows the high-level methodology for forecasting residential customers on our network.

Figure 7-1: High-level methodology of customer forecasting at the zone substation level



Once the customer number forecasts for the various network elements have been developed, we review them against historical growth rates as a top-down check that the forecast growth rates are consistent with the trend for the specific network element. For example, if a feeder is showing signs of an initial ramp up in growth rates, the forecast will be reviewed to ensure the growth over the short to medium term (and into the long term) is reflective of relative growth rates geographically and into the future.

7.4.2 Customer numbers – historical and forecast

As illustrated by the table below, our total customer base has been growing by approximately 1.8% per annum during the current regulatory period.

Table 7.2: Actual (billed) customer numbers 1 Jul 2014 to 30 Jun 2019

Customer type	2014-15	2015-16	2016-17	2017-18	2018-19	Growth rate p.a.
Residential	612,057	624,248	636,741	649,069	661,659	2.0%
Commercial	68,084	67,899	67,952	68,186	68,426	0.1%
Industrial	2,416	2,486	2,562	2,628	2,678	2.6%
Total	**682,557**	**694,633**	**707,255**	**719,883**	**732,763**	**1.8%**

Residential customers comprise approximately 90% of our total customer base. During the last 4 years, we have experienced an annual growth rate of 2.0% for this customer type. At the same time, industrial customer growth has kept pace, particularly large (predominantly low voltage) businesses such as supermarkets and home/hardware stores, and which are more energy-intensive than the commercial segment. These large customers have been connecting to service the steady growth in the residential customer base.

The trend for commercial customers in the first two years of the current regulatory period was negative, indicating that commercial disconnections outpaced new connections. However, economic conditions subsequently improved, evidenced by a subsequent incremental increase in the number of small businesses within our network.

We forecast that our customer base would grow at 1.7% per annum during the 2016-2020 regulatory period. This is in line with the actual growth reported in Table 7.2 (above).

Over the 2022-26 regulatory period we expect the total customer base to increase by 1.6% per year, which means connecting more than 62,000 new customers over the period. Table 7.3 (below) shows the detailed breakdown of our forecast. The total number of customers on our network is forecast to increase to over 820,000 by 2025-26.

Table 7.3: Customer number forecasts 1 Jul 2021 to 30 June 2026

Customer type	2021-22	2022-23	2023-24	2024-25	2025-26	Growth rate p.a.
Residential	697,378	710,108	722,978	736,043	749,148	1.8%
Commercial	69,202	69,429	69,644	69,859	70,082	0.3%
Industrial	3,006	3,059	3,112	3,164	3,214	1.7%
Total	**769,586**	**782,596**	**795,734**	**809,066**	**822,443**	**1.7%**

For residential customers, we expect an increase of 7.4% by the end of the upcoming regulatory period. This primarily reflects projected growth within the VIF publication.[3] Consequently, this trend in population will be reflected in our network via a rise in the number of households. Given that our distribution network includes growth corridors with significant population and development projections, our customer numbers are expected to increase.

The growth is concentrated in key urban local government areas such as Whittlesea and Casey, which are located on the northern and south-eastern fringes of our metropolitan Melbourne network. Within our rural regions, the Shire of Baw Baw is also expected to grow strongly, thus contributing to a residential customer number increase.[4] Additionally, there are no local government areas within our network where the VIF publication has projected a decline in population.

While there has historically been low to nil growth in the commercial customer base, there is a likelihood for an upturn in economic activity within the 2022-26 regulatory period, which would encourage new entrants in this sector. As a result, the commercial customer segment is expected to increase marginally.

Overall, a steady customer growth of approximately 1.7% per annum is forecast over the 2022-26 regulatory period.[5] This growth will be led primarily by the residential and industrial sectors. The forecast suggests that industrial businesses will connect in response to the growth in residential customers.

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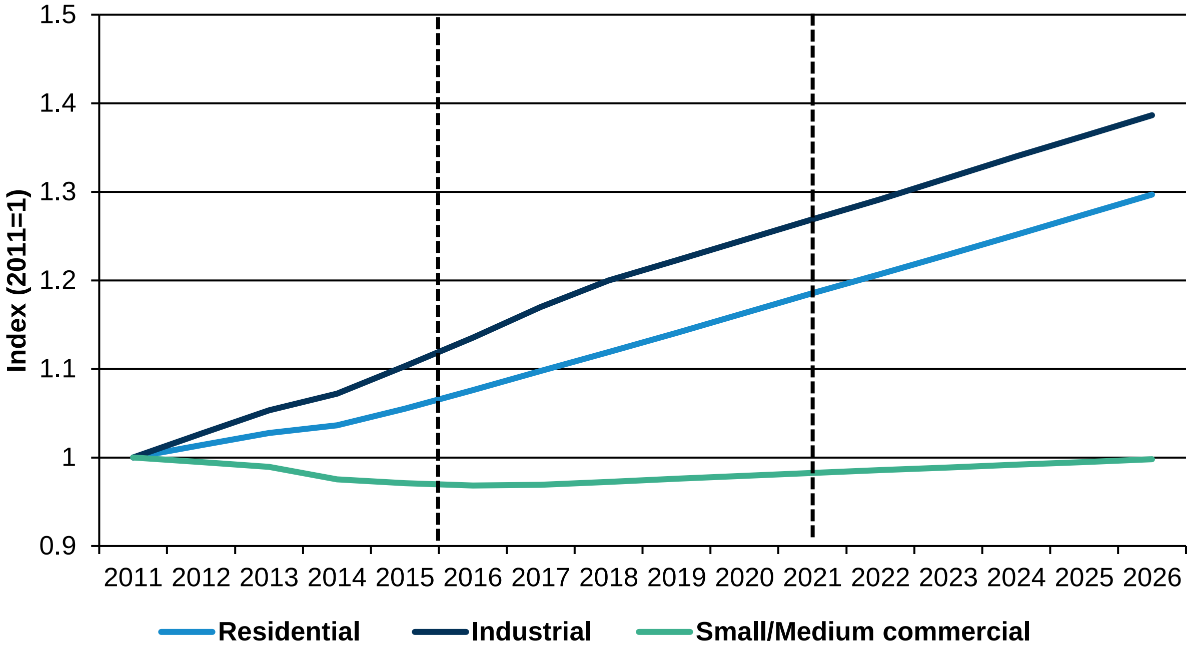
3 The State of Victoria Department of Environment, Land, Water and Planning, *Victoria in Future 2016*, p. 4.

4 Ibid.

5 This number is calculated as the total number of new connections less abolishments (disconnections). These customer forecasts, and the resulting demand forecasts in section 7.6, are key inputs to our augex forecasts (Chapter 9). Capex on new connections rely on 'gross' customer connections, while demand and energy forecasts use 'net' connections, with the number of abolishments being the difference between the two. Furthermore, connections capex is based on the number of physical connections, rather than the number of customers. This is particularly relevant for non-residential connections. For example, a new shopping centre will count as one 'connection' for capital expenditure forecasting purposes, but many new 'customers' for energy forecasting purposes. Therefore, the 'connections' in regulatory template 2.5 will not equal the 'customers' in our demand and energy forecast models.

The historical and forecast growth rate for each customer group since 2011 is depicted in Figure 7-2. Because of the large differences in the customer numbers across segments, Figure 7-2 is presented as an index, with each customer segment's growth baselined at 1 in 2011.

Figure 7-2: Customer growth 2011-2026 (financial years, index)



Source: AusNet Services.

7.5 Energy consumption forecasts

7.5.1 Energy consumption forecast methodology

Energy consumption is the measure of total energy used by all customers over a period of time. Energy consumed is measured in watt hours (or multiples of) over a defined period. In the current environment, most of our tariffs are 'energy-based'. That is, network tariffs are based on the amount of energy consumed by customers over a given timeframe.

Energy consumption does not drive our capex requirements, but it is relevant for setting network tariffs that include consumption-based charges. Under the current revenue control mechanism, consumption forecasts are used to determine the forecast price path associated with the revenue cap. However, any gains or shortfalls in revenue due to differences in actual and forecast energy consumption are automatically adjusted for when the subsequent year's prices are approved. Therefore, inaccurate forecasts can lead to variances in annual revenue and year-to-year volatility in customer prices. As a result, accurate energy consumption forecasts need to account for the potential magnitude of growth, but also the possibility of a decline.

Due to improvements in energy efficiency (including more energy efficient appliances and industrial processes), adoption of rooftop solar and customers' responses to higher overall electricity prices, the total amount of electricity consumed by our customers from the network has declined. Energy forecasts are separately formulated for residential and non-residential customers, given their different consumption characteristics such as sensitivity to weather. When the impacts of technologies and government policies[6] are known with enough confidence, they are factored into annual energy forecasts.

[6] Such as the Victorian Solar Homes Package.

Energy sales forecasts are broadly based on several factors:

- economic growth;
- electricity prices;
- weather conditions;
- government policies; and
- changes in the use of DER.

Our forecasts also consider the increasing penetration of rooftop solar panels, which reduces energy consumption across the network. Climate change trends are considered to have a negligible impact over the forecast outlook period and so this is not included as an adjustment.

Figure 7-3: AusNet Services' detailed approach to energy forecasting

Forecast customer numbers by individual tariff

- The net growth in customers in each of our tariff codes, including any transfers between tariffs.

Weather correlations

- Regression analysis is used to determine the relationship between weather and energy consumption, at the tariff level. As a result, each tariff code has its own correlation which is used to profile energy consumption over the year.

New v. existing customers

- Smart meter data tells us that new customers use less energy per capita than the existing average customer. Therefore, any new customers added to the model are modelled, using lower energy per customer volumes.

Impact of solar PV uptake

- We forecast the number of customers who will install solar PV over the period, and the associated reduction in energy delivered from the network at times of solar generation.

Price elasticity

- Retail electricity price forecasts are sourced from AEMO and price elasticities for residential, commercial and industrial customers are applied to these prices. We model each category separately, which results in a more robust forecast.

Future energy efficiency impact

- Any continued energy efficiency improvements and/or schemes are separately modelled.

Impact of new technologies/policies

- The energy forecast model contains modules to include the impacts of emerging technologies on energy consumption.

7.5.2 Historical and forecast – energy consumption

Energy consumption from the network has been declining since 2010. There are several factors influencing this decline, including:

- greater access to energy efficient electrical appliances;[7]
- the impact of improved building standards, which require 6-star energy ratings in the design and build of new homes and major extensions;
- energy efficiency policies focused on the residential and commercial sector;
- growth in the number of rooftop solar PV installations and other DER;
- changes in consumer behaviour stemming from increasing electricity prices and demand management opportunities;
- education on greenhouse emissions and other environmental impacts; and
- weak economic conditions for the commercial and industrial sectors.

Under the revenue cap form of price control, annual changes in prices will correct for any differences between actual and forecast revenue in the preceding tariff year. Our annual energy forecast accuracy is high and minimises price impacts for customers from over or under-forecasting electricity volumes. Table 7.4 (below) shows the historical energy consumption for the previous three years, compared to the AER-approved forecast. It is evident that our forecast has been extremely close to actual consumption, particularly for 2018.

Table 7.4: Actual versus forecast energy consumption 2015-18 (GWh)

	2015-16	2016-17	2017-18
Actual	7,594	7,579	7,459
Forecast	7,457	7,458	7,453
Difference	**1.8%**	**1.6%**	**0.1%**

The recent Solar Homes Package[8] offered by the Victorian Government is a major contributing factor to the forecast for residential customer energy consumption. This is because the increase in the installation of solar PV and a preference towards battery storage should result in customers using less energy transported by the network in comparison to historical levels. Additionally, the energy-based retail tariffs for solar should act as an incentive for residents to increase their proportion of self-usage behind the meter.

We consider that each of the above factors are highly likely to affect the amount of energy distributed over the 2022-26 regulatory period. Furthermore, some of these issues will result in higher energy usage (e.g. electric vehicles, fewer gas connections) while others may result in lower energy (e.g. solar combined with storage). The number of solar customers is expected to increase by around 60% between now and 2026 and, considering the size and mix of each system, we expect the installed solar capacity to double in size as seen in Figure 7-4.

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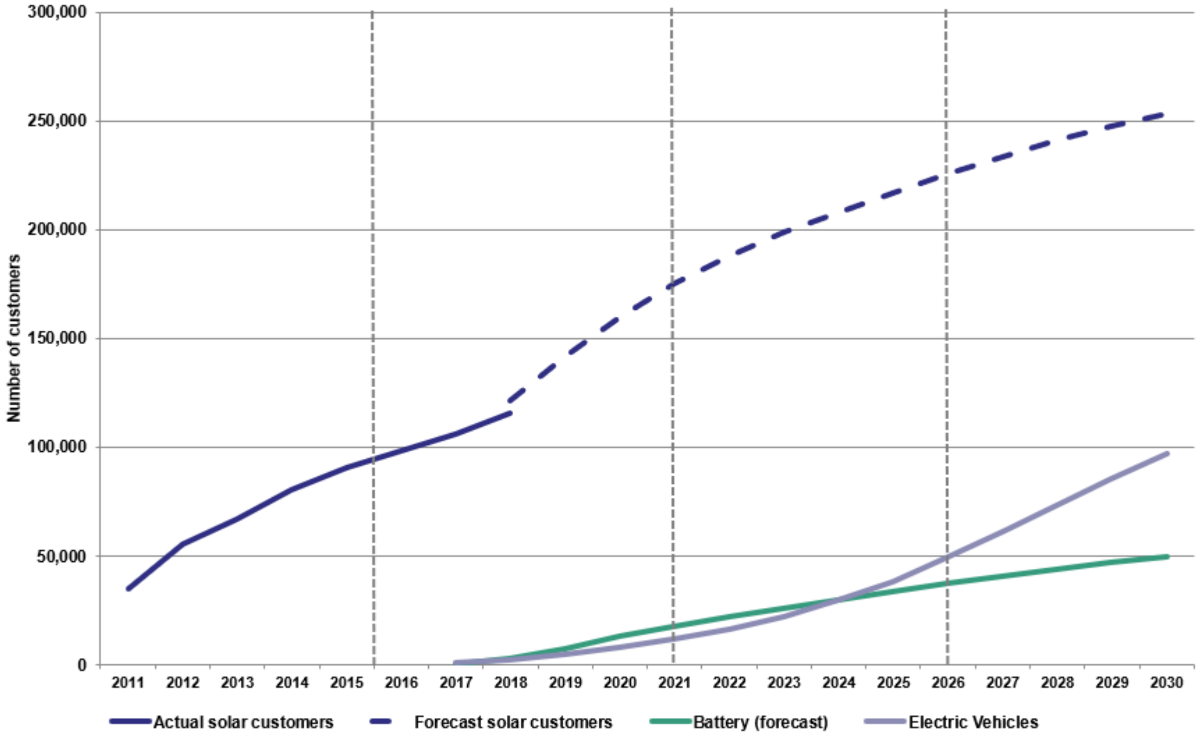
[7] Victorian Energy Upgrades government program that gives households and businesses rebates or discounts on energy saving products.

[8] Eligible households can claim a rebate up to $2,225 on the cost of a solar panel system.

Figure 7-4: Forecast solar customer numbers, batteries and electric vehicles



Source: AusNet Services

Over the 2022-26 regulatory period, we are forecasting electricity consumption to resume its gradual decline. The rapid growth in solar connections, plus the ongoing effects of energy efficiency, will continue to drive reduction in residential and commercial energy consumption on both a total and per customer basis, moderated by a small increase in consumption by low voltage industrial customers who are servicing residential customer growth. The forecast energy over the 2022-26 regulatory period is disaggregated into customer segments below.

Table 7.5: Electricity volume forecasts 1 Jul 2021 to 30 June 2026 (GWh)

Customer type	2021-22	2022-23	2023-24	2024-25	2025-26	Rate p.a.
Residential	2,898	2,848	2,805	2,767	2,733	-1.5%
Commercial	1,320	1,311	1,305	1,299	1,293	-0.5%
Industrial	3,082	3,099	3,119	3,138	3,157	0.6%
Total	**7,300**	**7,259**	**7,229**	**7,204**	**7,183**	**-0.4%**

The increasing number of solar customers on our network is a clear, but not the sole, underlying factor in the decline of energy consumption. Increased price responsiveness and a lower reliance in the macro economy on energy-intensive sectors have also played a role in the decline of energy usage. Overall, our forecasts are in line with the medium-term forecast of annual electricity consumption published by AEMO, which forecasts Victorian energy consumption to fall from 42.3 TWh to 40.4 TWh in 2020 to 2026.[9]

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9 2019 Electricity Statement of Opportunities, AEMO (Central scenario).

7.6 Maximum demand forecasts

7.6.1 Maximum demand forecast methodology

Capacity constraints on the distribution network due to growth in maximum demand are relieved with network augmentation (augex) when the investment becomes the efficient solution; the construction of network assets to increase the network capacity. In this context, demand refers to the total volume of electricity or energy required to be available to customers, and 'maximum demand' is the highest rate of energy use that occurs at a single point in time.

The maximum demand for electricity on our network generally occurs on hot summer days when temperature sensitivities drive a spike in demand.[10] Accurate demand forecasts ensure efficient levels of network investment are undertaken. This applies not only to investment decisions on traditional network infrastructure but also to demand management technologies. Identifying the areas in which demand management offers the most efficient outcome for customers relies on accurate predictions of maximum demand.

Maximum demand is a fundamental driver of our forecast augex. We deliver electricity to our customers and must therefore build, operate and maintain our network to manage expected changes in demand for electricity. In our network, peak demand typically occurs for short intervals when it has been extremely hot over consecutive days. It is during these periods, when maximum demand approaches the capacity of network assets, that the continued safe and reliable electricity supply to all customers becomes paramount.

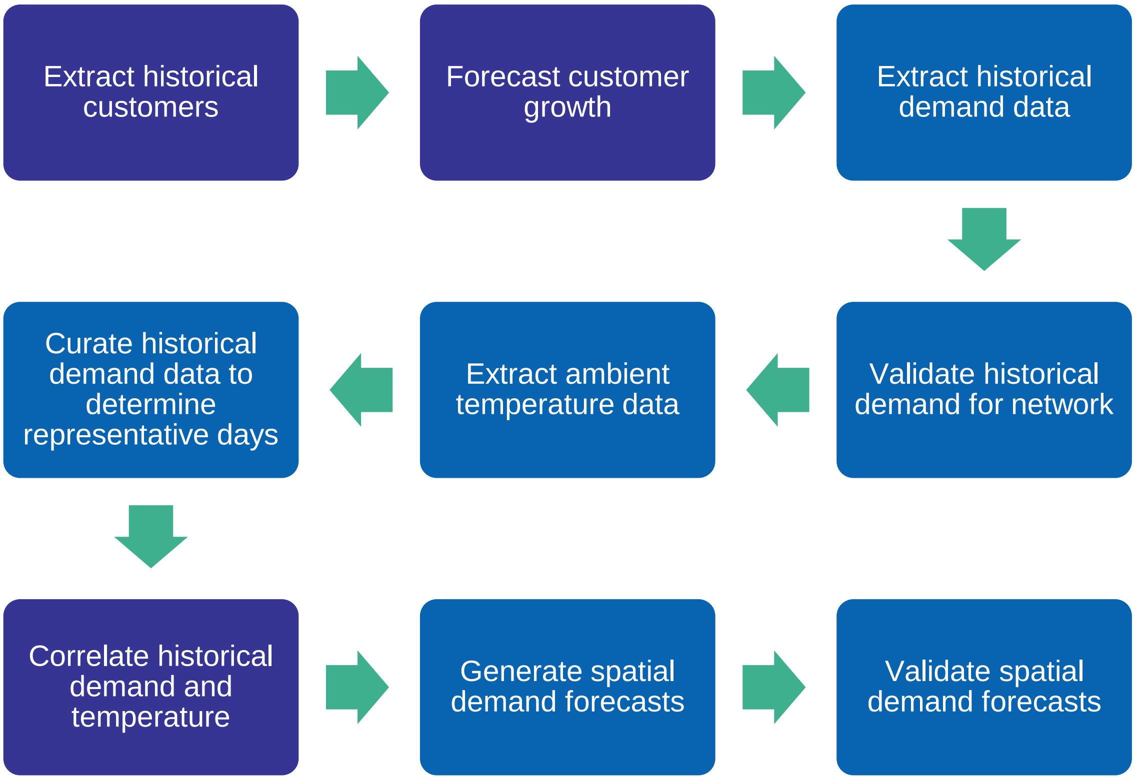
Peak demand trends are useful as lead indicators for network areas that require expenditure to accommodate growth in demand. When demand is forecast to be greater than the capacity of the network in an area, we must invest in the network, or implement demand management solutions to ensure the network can continue to match the peak demand required by our customers. This is to ensure that our customers do not experience interruptions to their supply when they need it most.

Our demand forecasts have been prepared using a robust process that combines detailed local knowledge with internal economic analysis. At a high level, the forecast is based on the key premise that higher demand is driven by higher cumulative temperatures. Analysis of historic customer loads and forecast customer growth are also important inputs to our demand forecasts, which are developed at the HV feeder, zone substation and terminal station levels.

The key steps involved in preparing demand forecasts are set out in Figure 7-5 (below).

10 We have a majority of summer peaking zone substations.

Figure 7-5: Overview of demand forecasting methodology



Source: AusNet Services.

Two key components of the demand forecasting methodology are (1) customer numbers[11] and (2) the relationship between temperature and demand. Population is one of the main drivers of growth in maximum demand, as it directly affects the number and type of customer connections. The most recent summer's actual demands (for summer peaking feeders) are used as the basis of the forecast. Due to the timing of the 2022-26 regulatory period submission, our demand forecast is based on the 2017-18 summer and 2018 winter maximum demands. Our revised proposal will include an updated forecast which considers the demand recorded (and the associated correlations with temperature) in the most recent summer.

As part of our continuous improvement processes, we engaged the Centre for International Economics (CIE) to conduct a review of our demand forecasting methodology. CIE prepared a comparison of our methodology and the methodology adopted by AEMO[12] and its findings is included as an appendix. CIE's review found that:

- our methodology was a reasonable approach to forecasting demand;
- our customer level data has almost complete coverage of the network and that this is likely to improve the quality of the forecasts as different approaches could be implemented for different customer types; and
- our approaches to population growth, economic growth, Cooling Degree Days (CDD) calculation, and energy efficiency were appropriate.

11 This includes all types of customers: residential, commercial and industrial.

12 AEMO Connection Point Forecasting Methodology, AEMO 2016.

The review recommended incorporating electricity prices into the model as our methodology may have overstated demand from 2000 to 2019 and may understate demand for the 2022-26 regulatory period when compared to AEMO forecasts.[13] However, in our view, the relationship between maximum demand and price is complex and quite different to the relationship between energy consumption and price.

Electricity prices have a more significant impact on energy consumption than peak demand. Our experience in developing demand management programs is that both residential and commercial customers place a high value on cooling during extreme temperature days and therefore display a price-inelastic behaviour at these times. Furthermore, AMI meter data suggests that annual changes in peak demand are not negatively correlated with annual changes in electricity prices. That is, we can discern no robust relationship between increasing electricity prices and decreasing maximum demand at the customer level.

Price trends are, therefore, not incorporated within the demand forecast methodology as the magnitude of changes in retail price that could be reasonably expected over the outlook period are not considered sufficient enough to drive material changes in peak demand.

CIE also recommended that we consider allowing for additional idiosyncratic variation in non-thermal factors during the curation and data cleaning process to avoid producing a sensitive starting point and potentially underestimating maximum demand. Our process seeks to identify outliers that may warrant being excluded, and to develop a curated set of data that is representative of the relationship between maximum demand and CDD. This ensures that the selected starting point contains a representative amount of non-temperature driven load and avoids any opportunity for the inflation of non-temperature effects adding into the starting values. It is important that non-temperature effects are not completely excluded from the methodology as these represent a portion of the load with a probability of occurring. The final revision step is to sense check the consistency of the forecasts against actual maximum demand values. Growth areas are reasonably expected to show increases in starting values while more established areas may have slight variations.

7.6.2 Historic and forecast maximum demand

In contrast to energy consumption, peak demand has increased significantly over the longer term (Figure 7-6). The historical data is heavily influenced by weather variation in the short term and demand forecasting involves normalising for this effect. Therefore, while demand declined between 2013 and 2015 (influenced by mild weather), it has grown since 2015.

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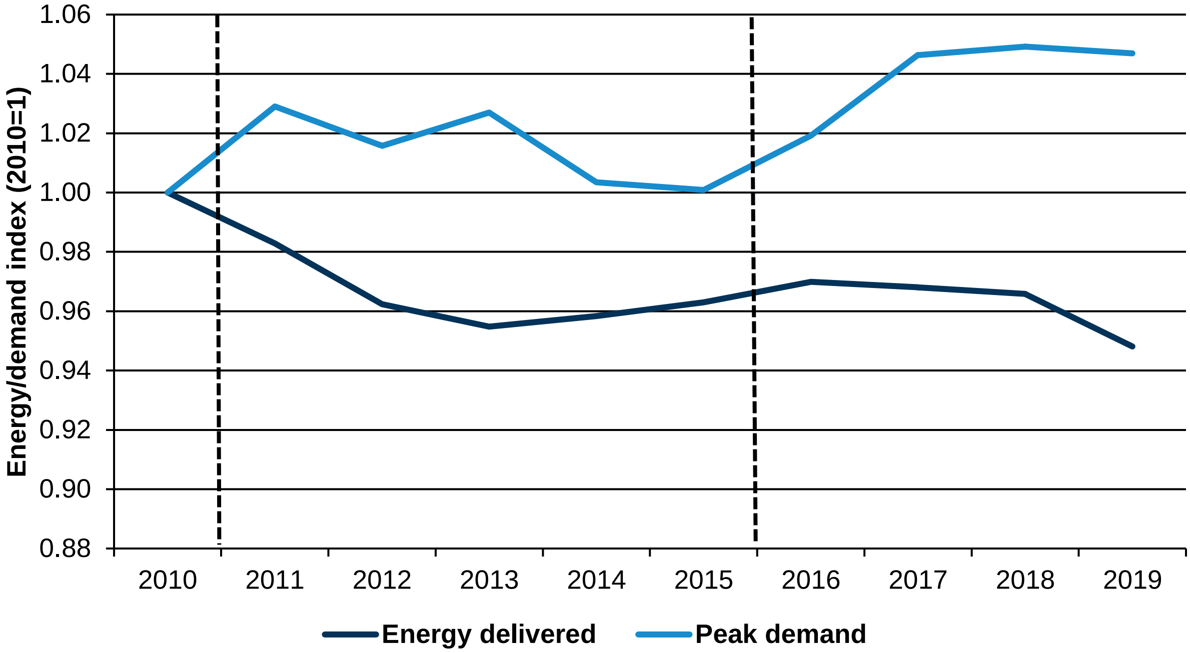
13 This is due to prices increasing in the 2000 to 2019 period, compared to AEMO's forecast of a decline in retail electricity prices in the forecast period.

Figure 7-6: Energy consumption/maximum demand index 2010-2019 (2010 = 1)



Source: AEMO and AusNet Services.

The growth in maximum demand since 2015 has been driven by customer growth and increased penetration of air conditioning units by both commercial business and residential households. Despite the recent improvements in energy efficiency and design, air conditioners remain relatively high-energy consuming appliances and generally contribute towards a significant amount of average customer energy bills.

As already noted, residential customers comprise a higher proportion of total energy consumed on our network compared to the other Victorian DNSPs.[14] Therefore, the impact of air conditioners at peak times is more pronounced in our network.

This also means that, at a network level, our time of peak demand is relatively late in the day compared to other networks. By the time our network reaches its demand peak, the output from solar PV installations is minimal, meaning that solar customers still rely on the network, rather than their solar panels, to meet their demand for electricity.

We have utilised AMI data to great effect to determine the impact of increasing energy efficiency and dwelling size on peak demand over time. As already noted, there is a trend towards lower energy consumption in newer houses, which are built to new energy efficiency standards and typically feature newer, more energy efficient appliances. Our work also explicitly recognises that new customers tend to be much more energy efficient than existing customers.[15]

However, AMI data shows that the impact of energy efficiency at the time of peak demand is showing signs of slowing, or even coming to an end. That is, at peak demand times, newer houses do not have an observably lower peak demand than houses constructed one or two years before. This is not the case for energy consumption, with new houses continuing to use less energy each year.

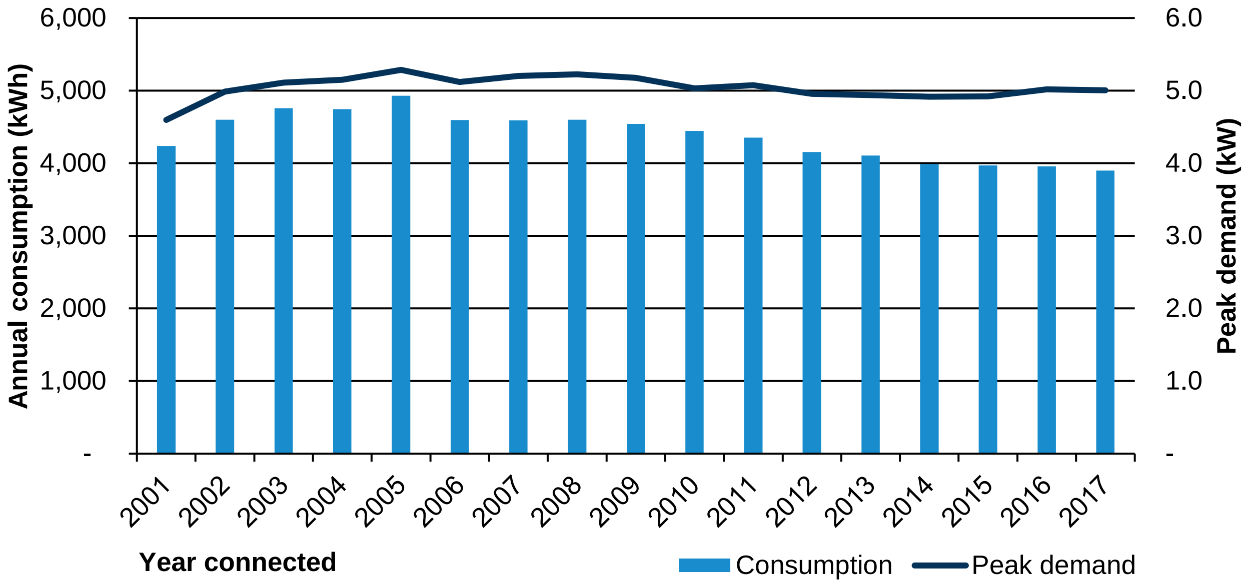
The impact of energy efficiency on consumption and peak demand is demonstrated in the next two charts. The first chart depicts non-solar dwellings, grouped into the year they connected. The data shows the average consumption and peak demand for these customers in 2018 and

14 Sourced from economic benchmarking data.

15 This is usually due to newer housing/dwelling types and the use of energy efficient appliances.

that while average consumption for newer houses is lower, there is very little difference in peak demand. As an example, a customer who connected in 2017 consumed 11% less energy, on average, than a customer who connected in 2011, but they both had the same average peak demand.

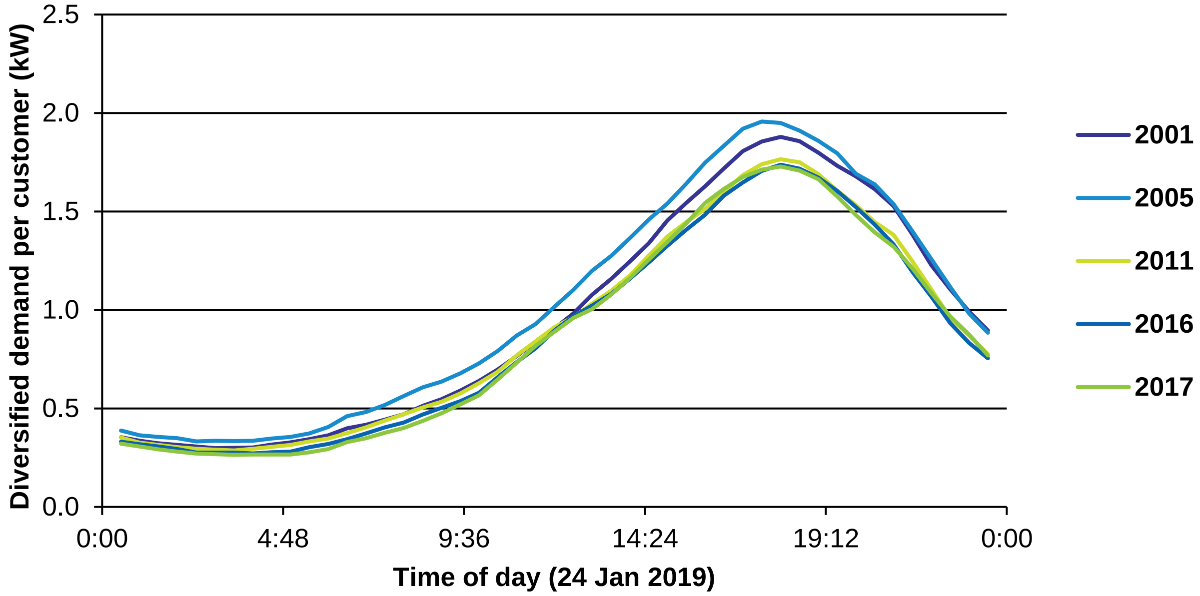
Figure 7-7: 2018 energy consumption and peak demand (non-solar) by year connected



Source: AusNet Services.

The next chart adds more evidence to the observation that energy efficiency at the time of peak demand is coming to an end. It is slightly different to the above chart in that the data is on a diversified (or coincident) basis on a peak demand day and therefore overall demand is lower. The data shows that on this day (24 Jan 2019), newer houses had the same peak demand as houses that connected to our network in 2011.

Figure 7-8: Residential demand profiles on 24 Jan 2019 by year connected



Source: AusNet Services.

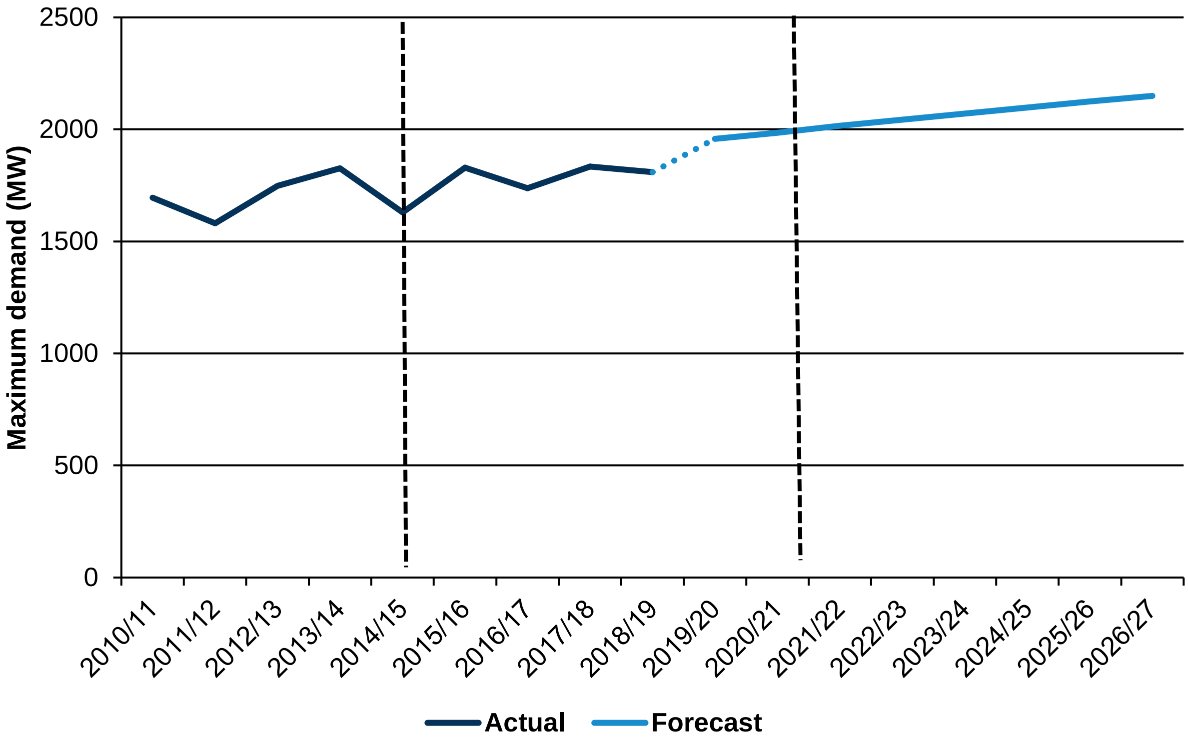
We forecast moderating growth in maximum demand over the forthcoming regulatory period, which is consistent with the trend in demand growth in the current regulatory period. Over the 2022-26 regulatory period, maximum demand is expected to grow at 1.3% per annum at the network level, as depicted in Table 7.6.

Table 7.6: Maximum demand: current and forecast regulatory period (non-coincidental, MW, at zone substation level, POE50)

	2016-17	2017-18	2018-19	*2019-20*	*2020-21*	*2021-22*	*2022-23*	*2023-24*	*2024-25*	*2025-26*
Demand	1,737	1,834	1,809	*1,962*	*1,989*	*2,016*	*2,043*	*2,071*	*2,098*	*2,125*
Growth rate	-5%	5.6%	-1.4%	*8.5%*	*1.4%*	*1.3%*	*1.3%*	*1.3%*	*1.3%*	*1.3%*

The maximum demand forecast for the 2022-26 regulatory period is slightly higher than the actuals for the 2016-20 regulatory period due to the combination of the increase in customer numbers and higher cumulative temperatures. Peak energy delivered from rooftop solar PV in summer coincides with peak network demand arising from air conditioning load. We do not expect demand to deviate greatly from the forecast unless there are extreme weather events.

Figure 7-9: Summer peak demand trend 2012 – 2026 (POE50, MW)[16]



Source: AusNet Services.

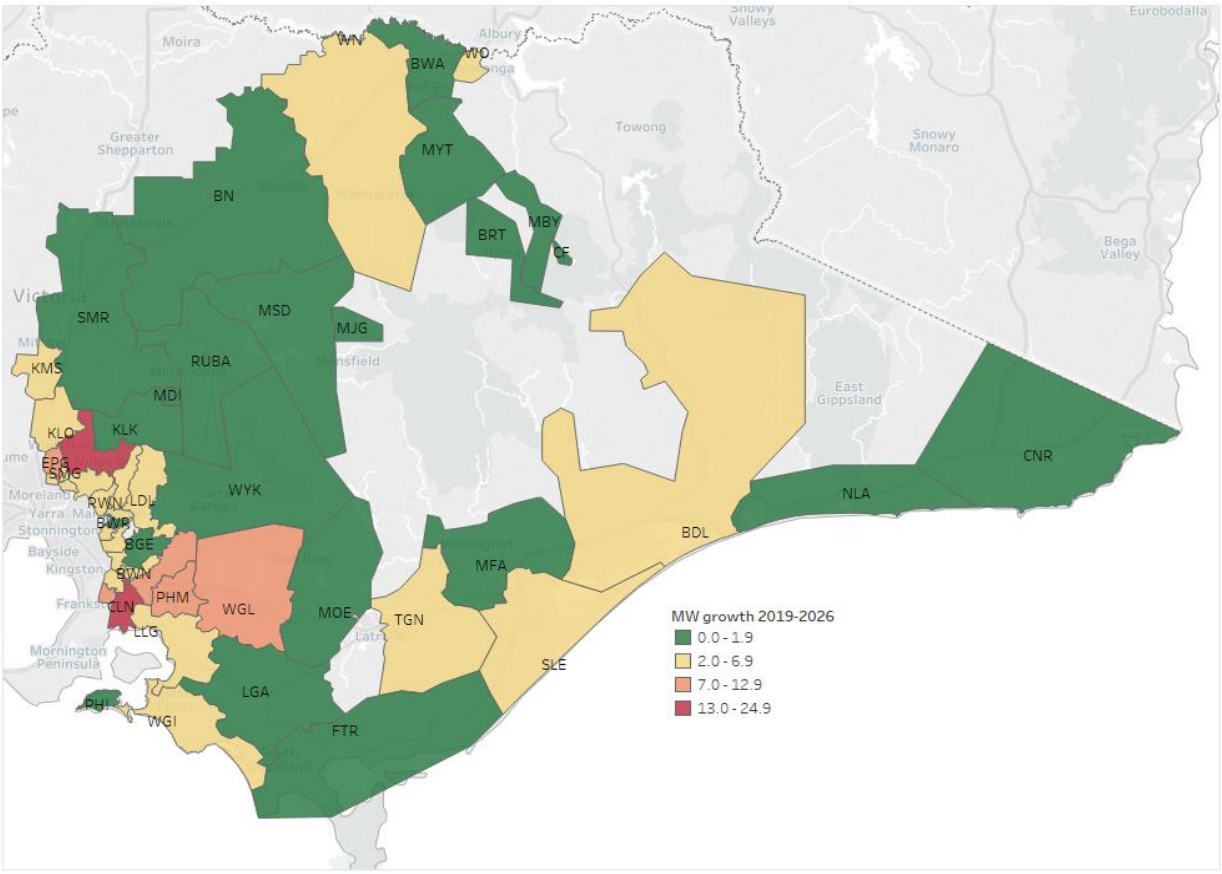
[16] POE is Probability of Exceedance of demand forecasts. The demand is expressed as the probability the forecast would be met or exceeded. A 50% POE implies there is a 50% probability of the forecast being met or exceeded.

Demand growth within the network is focused in two major growth corridors in Melbourne's north and southeast. More than two-thirds of growth in demand is in the population centres served by seven of our zone substations:

- Clyde North;
- Cranbourne;
- Officer;
- Pakenham;
- Warragul;
- Doreen; and
- Epping.

The red areas in the metropolitan area (Doreen and Clyde North zone substations) are our urban high growth corridors. The areas in orange also have significant demand growth. Figure 7-10 shows that most of our network is forecast to have a lower degree of growth in demand (green areas) over the 2022-26 regulatory period (approximately 1% per annum).

Figure 7-10: Maximum demand growth 2019-2026, by zone substation

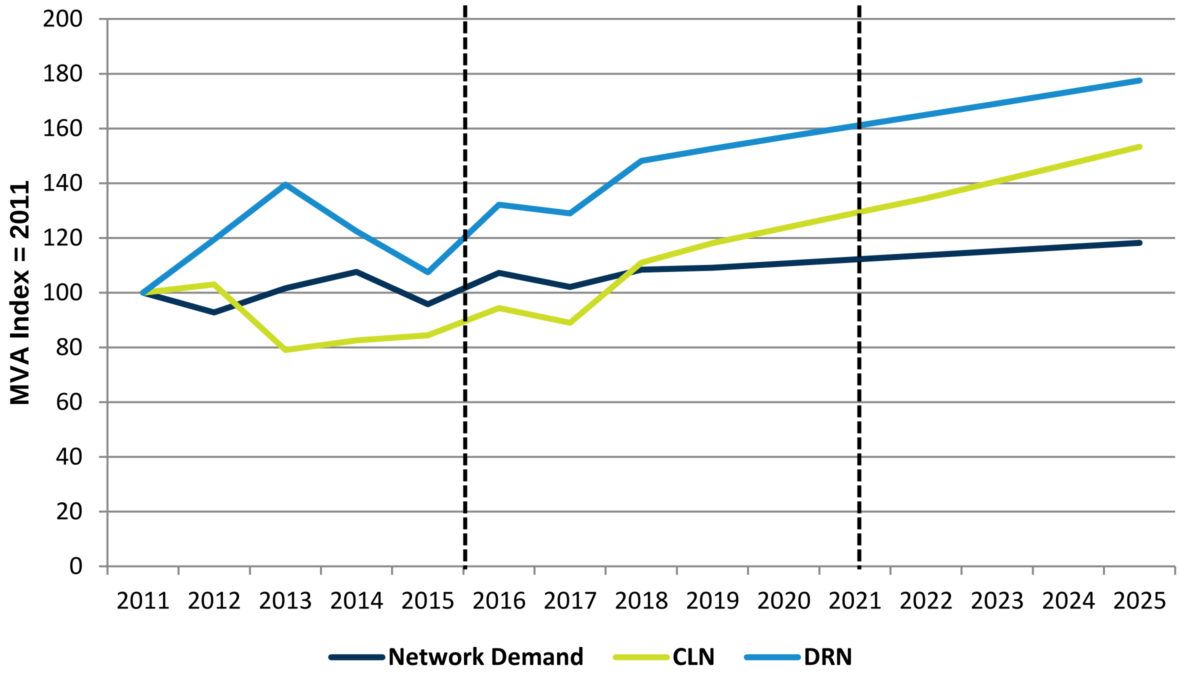


Source: AusNet Services.

There is also a significant concentration of peak demand in the key population growth corridors in Melbourne's north and south-east. Based on a 2011 index, the actual rate of growth in maximum demand in the Clyde North and Doreen zone substations outpaced network demand in 2017 (see Figure 7-11). This trend is forecast to continue throughout the 2022-26 regulatory period. In 2013, the commissioning of Cranbourne zone substation contributed to the fall in demand at Clyde North (i.e. a planned off-loading of Clyde North zone substation). Similarly, the maximum demand at Doreen fell as we commissioned South Morang zone substation. This reinforces the fact that growth in these areas has been significant relative to the rest of our network.

Clyde North and Doreen zone substations are of note as they were the focus of our initial augmentation capital expenditure negotiations with the Customer Forum. Our negotiations with the Customer Forum resulted in augmentation at Clyde North being included in our forecast, with a requirement to augment Doreen zone substation expected in the regulatory period beginning 1 July 2026. Further details on our capex proposals are in Chapter 9.

Figure 7-11: Network demand compared to Clyde North and Doreen (measured in MVA)



Source: AusNet Services.

7.6.3 Comparison to AEMO forecast

AEMO, in its role as the national transmission planner, produces an independent regional forecast and terminal station maximum demand forecast for each network region[17] over a 20-year timeframe.[18] AEMO forecasts maximum demand by season using a probabilistic methodology at the transmission connection point (TCP) level. We also use temperature corrected demand forecasts at 10% POE and 50% POE, depending on whether we are assessing our network under system normal conditions or with elements of plant out of service (N-1) respectively.

AEMO's 2019 TCP forecasts for our distribution area predicts that demand at our terminal stations will grow at an average annual rate of 0.4% between 2020 and 2026. This is a significant step down from AEMO's previous (2018) TCP forecasts, which projected average annual growth of 1.4% - in other words, in line with our own expectations.

[17] AEMO produces state-wide forecasts for Victoria.

[18] We prepare demand forecasts at three levels. The lowest level is feeder level, of which there are over 300 in number. The feeder forecasts are aggregated then roll up to the zone substation level which are in turn aggregated to the terminal station level. AEMO, which is responsible for planning decisions in Victoria's transmission network, produces forecasts only at the terminal station level.

With respect to AEMO's 2019 forecasts, we note:

- AEMO's maximum demand methodology was revised in 2019 and now uses an ensemble model approach to estimate base year distribution of demand and long-term forecasts. The magnitude of the above-mentioned change between the 2018 and 2019 forecasts suggests that further testing of the accuracy of AEMO's latest forecasts is required.[19]
- We understand that AEMO's energy efficiency assumptions for businesses have also markedly increased in 2019 based on the inclusion of savings from small and medium manufacturing enterprises under the Victorian Energy Upgrades program. We remain sceptical of the ability of commercial and industrial customers to significantly contribute to peak demand reductions in our residential-dominated network. AEMO has also factored in the potential for future government energy efficiency schemes during the regulatory period which are yet to be formally announced. If these schemes do not eventuate, this would overstate AEMO's energy efficiency forecast and subsequently understate the maximum demand forecast.
- AEMO utilises a different approach to weather normalisation to us, which result in our forecasts adopting different starting points. Additionally, AEMO produces state-wide demand forecasts and its reconciliation of these to individual terminal station forecasts can result in different demand growth rates.
- AEMO and us are forecasting growth in the Clyde North and Doreen zone substation areas (respectively supplied by the Cranbourne and South Morang terminal stations).

7.7 Why our forecasts satisfy the Rules requirements

The AER accepted our forecasts for customer numbers, energy consumption and maximum demand in the 2016-20 regulatory period. Since then, we have improved our forecasting practices to ensure they continue to result in prudent and efficient network investment decisions.

Our forecasts for customer numbers, energy consumption and maximum demand are a realistic reflection of expected demand during the 2022-26 regulatory period. Furthermore:

- our forecasting methodologies have been refined, building on our strong track record of preparing accurate forecasts;
- the most up to date available information have been adopted in preparing our forecasts, including the additional information obtained from smart meters;
- the forecast maximum demand trend is in line with a projected increase in customer numbers;
- our forecasting methodologies are demonstrably sound and capable of producing realistic forecasts; and
- our forecasting methodologies have been independently verified as a reasonable approach to forecasting demand by CIE.

7.8 Supporting documentation

We have included the following documents to support our maximum demand forecast:

- Appendix 7A: The CIE - Distribution Demand Forecasting Review - 191119 – PUBLIC; and
- Appendix 7B: Demand Forecasting Methodology - 130919 – PUBLIC.

[19] AEMO's TCP forecasts tend to fluctuate between growth and flat outlooks on a year-to-year basis. History suggests that just because the 2019 forecast is flatter than the 2018 forecast (but still growing), does not mean that the 2020 forecast will not return to a steeper growth profile.

8 Building Block / Revenue Requirement

The remainder of Part III of this regulatory proposal (including Chapters 8 through to 18) sets out the required revenue for Standard Control Services (SCS).

Standard Control Services are the primary distribution network services consumed by our customers and involve the provision of continuous connection and availability to the electricity grid. We are adopting the service classification set out in the AER's final Framework and Approach paper to determine which services are included in SCS.[24]

This chapter details the calculation of our annual revenue requirement, in accordance with the building block approach outlined in the NER and the AER's PTRM. A summary of the building block components, the unsmoothed and smoothed revenue for each year of the forthcoming regulatory period is presented, as well as the proposed cost pass throughs and the price control formula.

8.1 Key points

- The proposed revenue requirement is $3,420.5 million in unsmoothed nominal dollar terms.
- In real, smoothed dollar terms, the proposed revenue requirement is $3,186 million ($20201), or an average of $637 million, which is 2% below the expected revenue in 2016-20 regulatory period.

8.2 Chapter structure

The structure of the remainder of this chapter is:

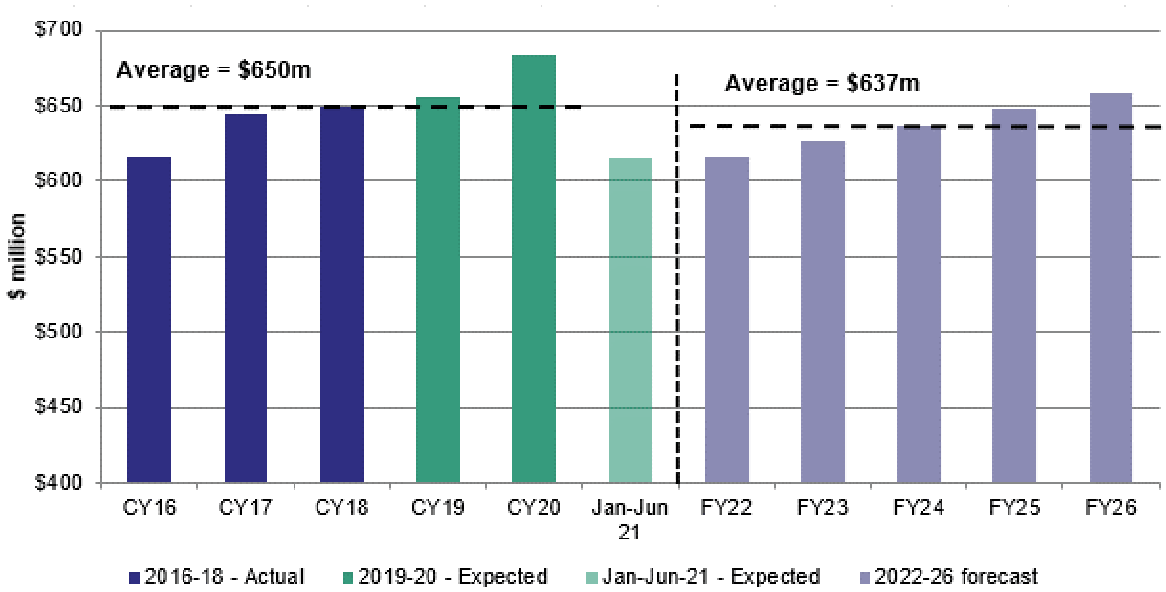
- Section 8.3 presents our revenue requirement;
- Section 8.4 presents a summary of the building block components of the revenue requirement;
- Section 8.5 presents our smoothed revenue requirement for each year of the forthcoming regulatory period, including a description of the X-factors adopted;
- Section 8.6 sets out the average price path for different customer types under the proposed revenue cap; and
- Section 8.7 sets out the relevant supporting documents for this chapter.

8.3 Summary of our revenue requirements

Based on the detailed inputs described and calculated in this proposal, our smoothed revenue requirements for 2022-26 is $637 million per annum ($2021).

[24] Appendix 8B – Service Classification Proposal.

Figure 8-1: Revenue requirement CY 2016 to FY 2026 ($m, real 2021)



Source: AusNet Services.

Note: The current regulatory period starting on 1 Jan 2016 has been extended by 6 months to include Jan to June 2021. For easier comparison, the Jan to June 2021 data is presented as an annual number on the chart.

8.4 Building block components of the revenue requirement

The building block components and our unsmoothed annual revenue requirements for each year of the forthcoming regulatory period are depicted in the table below.

Table 8-1: Unsmoothed Revenue Requirement ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Return on Capital	228.3	231.3	232.7	233.9	233.8	**1,160.0**
Regulatory Depreciation	138.2	149.8	156.2	165.5	174.4	**784.0**
Operating Expenditure	245.6	255.4	265.5	275.9	285.6	**1,327.9**
Revenue Adjustments	58.4	52.7	27.6	4.8	4.9	**148.5**
Net Tax Allowance	-	-	-	-	-	**-**
Unsmoothed revenue requirement	**670.6**	**689.1**	**682.0**	**680.0**	**698.7**	**3,420.5**

Source: AusNet Services PTRM.

The unsmoothed annual revenue requirement is calculated as the sum of the building block components, which are described in the sections below, and detailed in the chapters that follow.

8.4.1 Regulatory Asset Base

Our Regulatory Asset Base (RAB) has been calculated in accordance with the requirements of Clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capital expenditure (capex) forecasts set out in Chapter 9 of this proposal, the opening RAB based on expenditure in the current regulatory period as detailed in Chapter 12, and depreciation calculated in Chapter 13. The table below sets out a summary of the derivation of our RAB for the forthcoming regulatory period.

Table 8-2: Regulatory Asset Base ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	**4,715.1**	**4,898.9**	**5,061.6**	**5,225.3**	**5,370.5**
Net capital expenditure	321.9	312.6	319.8	310.7	319.9
Opening RAB inflation addition	115.5	120.0	124.0	128.0	131.6
Nominal depreciation	-253.7	-269.8	-280.2	-293.5	-306.0
Closing RAB	**4,898.9**	**5,061.6**	**5,225.3**	**5,370.5**	**5,516.0**

Source: AusNet Services PTRM.

8.4.2 Return on Capital

Consistent with the requirements of Clause 6.4.3(a)(2) of the NER, and in accordance with the AER's PTRM, the return on capital is calculated by applying the post-tax nominal vanilla WACC to the RAB for each year of the regulatory period. The table below illustrates the calculation of the return on capital building block. Full details of the WACC calculation are set out in Chapter 14.

Table 8-1: Return on capital allowance ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	4,715.1	4,898.9	5,061.6	5,225.3	5,370.5
WACC (% per annum)	4.84%	4.72%	4.60%	4.48%	4.35%
Return on capital	**228.3**	**231.2**	**232.7**	**233.9**	**233.8**

Source: AusNet Services PTRM.

8.4.3 Depreciation

The calculation of regulatory depreciation was carried out in accordance with the AER's PTRM and Clause 6.5.5 of the NER and is detailed in Chapter 13. Consistent with the requirements of Clause 6.4.3(a)(1) and (3) of the NER, we have incorporated an allowance for depreciation in its building block revenue requirement. The table below lists the regulatory depreciation building blocks for each year of the forthcoming regulatory period.

Table 8-2: Forecast depreciation ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26
Nominal depreciation	253.7	269.8	280.2	293.5	306.0
Less: indexation on opening RAB	115.5	120.0	124.0	128.0	131.6
Regulatory depreciation	**138.2**	**149.8**	**156.2**	**165.5**	**174.4**

Source: AusNet Services PTRM.

8.4.4 Operating expenditure

Consistent with the requirements of Clause 6.4.3(a)(7) of the NER, we have included a forecast of operating expenditure (opex) in its building block allowance. As explained in Chapter 10, the opex forecast has been prepared in accordance with all applicable requirements of the NER and the RIN.

Table 8-3: Forecast operating expenditure ($m real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Controllable opex (base, step and trend)	222.2	225.6	229.1	232.4	235.0	**1,144.2**
Guaranteed Service Levels	9.3	9.3	9.3	9.3	9.3	**46.7**
Metering systems reallocation	5.7	5.7	5.9	6.0	6.1	29.4
Innovation	0.2	0.2	0.2	0.2	0.2	1.2
Debt raising costs	2.3	2.3	2.4	2.4	2.4	11.8
Total	**239.8**	**243.3**	**246.9**	**250.4**	**253.0**	**1,233.4**

Source: AusNet Services Proposal Opex Model.

8.4.5 Other revenue adjustments

Consistent with the requirements of Clause 6.4.3(a)(5),(6) and (6A), we have incorporated the amounts that have been determined under the efficiency benefits sharing scheme (EBSS); the capital efficiency sharing scheme (CESS); and the shared assets guidelines. The detailed calculation of each of these building blocks was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 16 (Incentive Schemes), and Appendix 6A Shared Assets. The building block costs are listed in the table below.

Table 8-4: Incentive schemes and shared assets ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opex efficiencies (EBSS)	46.8	40.0	15.5	-5.8	-5.8	**90.7**
Capex efficiencies (CESS)	9.5	9.5	9.5	9.5	9.5	**47.5**
Shared Assets	0.0	0.0	0.0	0.0	0.0	**0.0**
Demand Management Innovation Allowance	0.7	0.7	0.7	0.7	0.7	**3.5**
Total	**57.0**	**50.2**	**25.7**	**4.4**	**4.4**	**141.7**

Note: AusNet Services PTRM.

8.4.6 Tax liability

Consistent with the requirements of Clause 6.4.3(a)(4) of the NER, we have incorporated an allowance for its benchmark tax liability into its building block allowance. The detailed calculation of the cost of tax is presented in Chapter 15 of this proposal. The cost of tax calculation accords with the requirements of Clause 6.5.3 of the NER and is summarised in the table below.

Table 8-5: Benchmark tax liability ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Tax payable	-	-	-	-	-	-
Less value of imputation credits	-	-	-	-	-	-
Net corporate income tax allowance	**-**	**-**	**-**	**-**	**-**	**-**

Source: AusNet Services PTRM.

8.5 Smoothed annual revenue requirement, X factor and revenue cap

The application of our X-factors in conjunction with our ‘Unsmoothed Revenue Requirement’ produces the following ‘Smoothed Revenue Requirement’.

Table 8-6: Annual building block revenue, X factors and maximum allowed revenue ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Annual building block revenue requirement (unsmoothed)	670.6	689.1	682.0	680.0	698.7	**3,420.5**
Annual expected MAR (smoothed)	631.2	657.6	685.0	713.6	743.4	**3,430.8**

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
X factor (%)	**4.18%**	**-1.69%**	**-1.69%**	**-1.69%**	**-1.69%**	n/a

Source: AusNet Services PTRM.

The PTRM Model attached to this proposal demonstrates that the smoothed and unsmoothed revenue requirements are equal in net present value terms in accordance with the requirements of Clause 6.5.9(b)(3) of the NER. The smoothed revenue for each year is also net of estimated non-tariff revenue from alternative control services.

The price path has been agreed with the Customer Forum. It delivers an initial reduction in prices, to deliver the full extent of the reduction at the start of the period, followed by annual price increases in line with inflation.

While Clause 6.5.9 requires the X factor to be set to minimise, as far as reasonably possible, the gap between smoothed and unsmoothed revenue in the final year of the regulatory period, we consider that the proposed price path satisfies this clause. It has not been reasonably possible to reduce the gap between smoothed and unsmoothed revenue in the final year of the regulatory period any further, given that this would not reflect the preferences of customers, or the agreement with the Customer Forum.

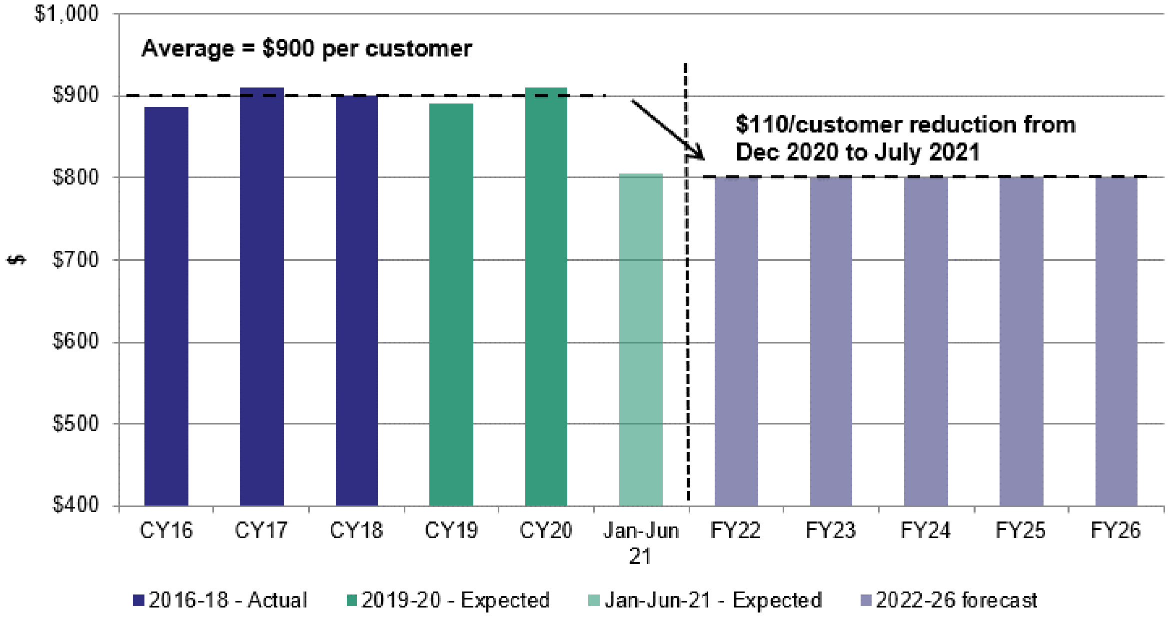
The revenue requirement will be subject to adjustments in accordance with the control mechanism (see Chapter 18) to account for:

- the actual CPI, in accordance with the provisions set out in Clause 6.2.6(a) of the NER;
- the annual return on debt update;
- our actual service standard performance, relative to its service standard targets, under the Service Target Performance Incentive Scheme; and
- any deemed cost pass though event, as nominated in Chapter 11 along with those pass through events specified in Cause 6.6.1 of the NER.

8.6 Average price path under the Proposed Revenue Cap

Revenue per customer will reduce in real terms by $110 between December 2020 and 2021-22 (i.e. ignoring the transitional period). It will then increase by inflation each year until the end of the regulatory period.

Figure 8-2: Revenue per customer ($, Real $Jun 2021)



Source: AusNet Services. Note: Jan to June 2021 is presented on an annualised basis.

8.7 Supporting documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following document is provided in support of this chapter:

- Appendix 8A – Shared assets.

9 Capital expenditure forecast

9.1 Key points

- In an increasingly complex environment, driven by unprecedented change and customers' new and evolving needs, our engagement with the Customer Forum and other stakeholders has helped shape our prudent and efficient capital expenditure (capex) proposal. We negotiated around 7% of our total net capex proposal with the Customer Forum and that negotiation, together with our broader stakeholder engagement, has helped ensure our capex proposal reflects significant savings and better reflects customers' preferences.
- We are proposing total net capex of $1,467.9 million ($2021) for the next financial year regulatory period (1 July 2021 to 30 June 26). This is 21% lower than our expected capex in the current calendar year regulatory period (2016-20) and will still allow us to meet our customers' needs, regulatory obligations and maintain the quality, reliability and security of supply. As such, our proposal should be accepted by the AER. Our prudent and efficient capex proposal is also a key output of the customer engagement we have undertaken over the last two years, including our trial of the New Reg process – a potentially precedent setting exercise that has necessitated significant resources and commitment to ensure its success.
- Our 2022-26 regulatory proposal builds on the outcomes we are achieving in the current regulatory period, where we are outperforming the AER's expenditure targets while maintaining reliability for customers and delivering significant programs that reduce, but not remove, the risk of bushfires.
- Ensuring our customers have safe and reliable energy is a key component of this regulatory proposal. We are achieving this by maintaining our ageing network and appropriately managing asset failure risk. Our replacement expenditure (repex) is $543.3 million ($2021), which is 14% higher than the expected repex ($476.3 million ($2021)) in the current regulatory period (noting that this information is presented on a basis that allows like-for-like comparison following some changes in cost categorisation). This proposed increase in repex is required to, among other factors, manage the unacceptable reliability and safety consequences of deteriorations in asset condition.
- Recognising that affordability is the primary concern for most of our customers, we have agreed with the Customer Forum to delay some of our major repex projects. We have done this only where the increase in reliability risk is relatively small. This approach has resulted in significant savings for customers – a significant (27%) fall from our initial proposal and a 3% fall from our Draft Regulatory Proposal. Our proposal for major project repex is now $75.7 million ($2021).
- Our augmentation capex (augex) proposal – capital needed to expand network capacity, including that associated with Distributed Energy Resources (DER) – is forecast to be $92.2 million ($2021). This is over a third lower (39%) lower than the augex we expect to incur in the current regulatory period and is largely driven by lower expected demand.
- Included in our augex proposal is $8 million ($2021) for a major project (Clyde North zone substation) that we proposed and agreed with the Customer Forum. This project is required to address growing customer needs (including reliability) from the large residential developments in Melbourne's urban growth corridors. Our proposal for major projects is significantly less (36%) than the augex proposal contained in our Draft Regulatory Proposal. This fall is largely due to the removal of a major zone substation project at Doreen (due to lower demand forecasts at the zone substation level).
- As our major bushfire safety investment program nears completion, we are proposing a reduction in our proposed safety related capex in the 2022-26 regulatory period. However, we

still require significant expenditure to complete Tranche 3 of the Rapid Earth Fault Current Limiters (REFCL) program and to maintain ongoing compliance with the REFCL legislation. Our proposal builds on the step change improvement in bushfire safety risk achieved in recent years and will ensure that safety risks continue to be managed in accordance with our legal obligations and our company values.

- Our information communications technology (ICT) proposal involves expenditure of $165.4 million ($2021). This is 12% lower than the ICT capex expected in the current regulatory period and is due to us leveraging technology and opportunities to reduce our costs. Our proposed ICT spend will help customers to continue to benefit from our services by replacing systems that are no longer fit-for-purpose and meeting regulatory obligations, including those associated with voltage variation and cyber security.
- Our ICT proposal will also help us deliver outcomes that we know our customers value. For example, our proposal includes targeted investment to accommodate the projected growth in export capacity from solar photovoltaics (PVs). It also includes a Customer Information Systems (CIS) program that will facilitate the provison of more personalised and tailored customer service, a very strong and consistent theme from our customer research, particularly from business customers.

9.2 Chapter structure

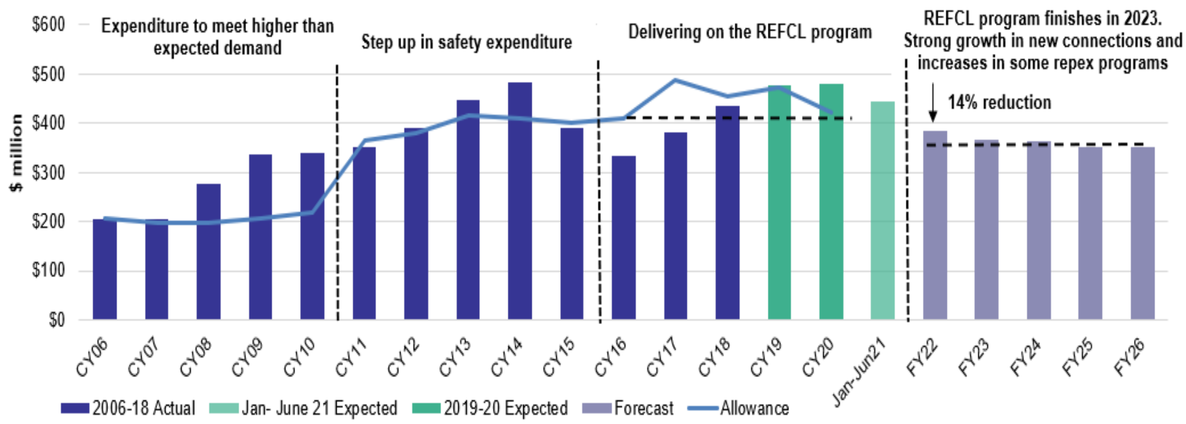
The structure of the remainder of this chapter is:

- Section 9.3 provides a summary of our capex forecasts, including a comparison with our historical expenditure by capex category.
- Section 9.4 discusses our customers' preferences in relation to capex outcomes, the feedback we received on our Draft Regulatory Proposal and how we have reflected this feedback, including customers' evolving needs, in this proposal.
- Section 9.5 sets out the key inputs and assumptions used in preparing our capex forecasts.
- Section 9.6 provides an overview of our forecasting approach, including our planning approach and our application of top-down adjustments to our forecasts.
- Section 9.7 summarises the scope of our capex negotiations with the Customer Forum and the negotiated outcomes.
- Sections 9.8 to 9.13 provides our forecast expenditure of our capex categories. For each category, we explain:
    - how our forecast compares with our historical expenditure;
    - the key drivers for the proposed expenditure;
    - the proposed projects and programs of work; and
    - how we tested and validated our proposed capex, including an explanation of any supporting modelling or benchmarking analysis.
- Section 9.14 explains our approach to delivering our proposed capex plans prudently and efficiently.
- Section 9.15 explains how our proposed capex satisfies the Rules requirements and therefore why the AER should accept it.
- Section 9.16 lists the key supporting documents for this chapter.

9.3 Summary of our capital expenditure forecasts

Following extensive engagement, including with the Customer Forum on agreed aspects of our capex proposal, we are proposing to invest (gross capital expenditure) $1,820.2 million ($2021) over the 2022-26 regulatory period. This is 14% or $287.4 million ($2021) lower than the expected capex in the 2016-20 regulatory period.

Figure 9-1: Gross capex, actual and forecast 2006 to 2026 ($m, real 2021)



Note: Jan to June 2021 is presented on an annualised basis.

The figure above also shows that we expect the capex in the current (2016-20) regulatory period to be 6% ($138.4 million ($2021) lower than the AER's regulatory allowance. The expected underspend in the current regulatory period reflects:

- $152.1 million ($2021) expected for augmentation capital expenditure (augex) in the current regulatory period. This is 63% ($58.8 million ($2021)) above the AER's allowance. The relatively high level of expenditure reflects, among other things, the reallocation of costs (from repex to augex) for a new Morwell zone substation and works at Bairnsdale zone substation.
- $476.3 million ($2021) expected repex in the current regulatory period. This is 18% ($105.5 million) under the AER's allowance and reflects some cost reallocation (see above), the introduction of data-driven asset management and the reprioritisation of programs to focus on delivering our safety capex (see below).
- $691.6 million ($2021) expected for safety capex in the current regulatory period. This is 18% ($150.8 million ($2021)) under the AER's allowance, noting that these figures do not capture the assets we have been replacing under the $74 million (Victorian) Government funded Powerline Replacement Fund (PRF). Successfully delivering the REFCL program and the projects under the PRF, have been the primary focus of our safety program during the current regulatory period.
- $492.2 million ($2021) expected for customer connections in the current regulatory period. This is 3% ($13.1 million ($2021)) under the AER's allowance notwithstanding lower than expected new connections. However, changes to our connections policy in 2018, which ensures we recover more connection costs directly from customers that are connecting, has ameliorated much of the decline we would otherwise have in the number of new connections.
- $188.4 million ($2021) expected for ICT in the current regulatory period. This is 17% ($38.4 million ($2021)) under the AER's allowance. While organisational changes contributed to relatively low levels of ICT capex at the start of the regulatory period, we expect expenditure to rise significantly towards the end of it. Nonetheless, it is a combination of deferrals, project efficiencies and reprioritisations that is driving the expected ICT underspend. For example,

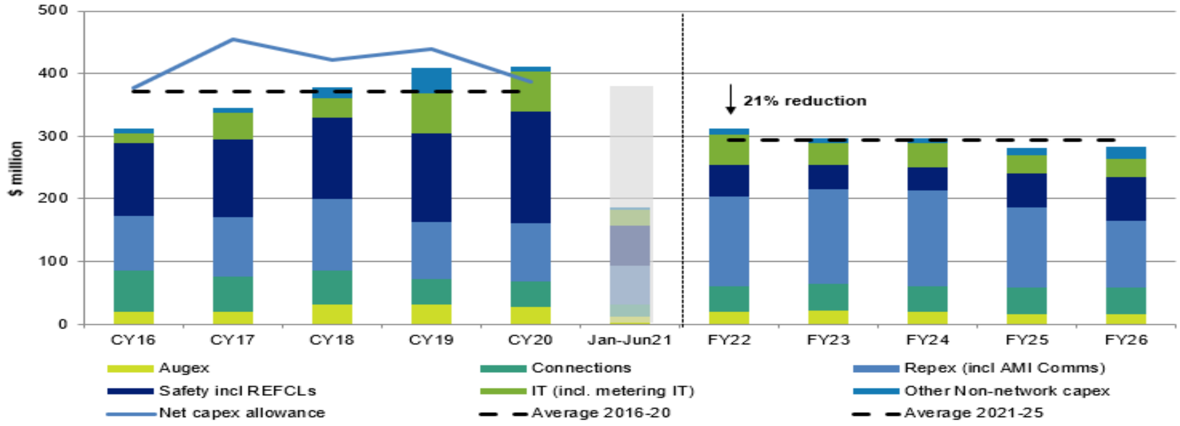
reprioritising resources to meet the obligations from the Power of Choice[25] reforms caused some deferment, while changes in the Network management program occurred due to improvements in our approach to DER and changes in the technology environment.

- $78.8 million ($2021) expected for 'other' non-network capex in the current regulatory period. This is 53% ($27.4 million ($2021)) above the AER's allowance due to an accounting change for the treatment of capitalised leases. Removing this accounting change from consideration of 'other' non-network capex results in a level of expenditure 11% lower than the AER's allowance.

The expected underspend in total capex in the current regulatory period can be viewed as savings that will be passed on to our customers. This is because the value of our asset base at the start of the 2022-26 regulatory period will be lower than would otherwise have been the case.

Reflecting customer contributions, the figure below provides a more detailed view of our net capex over the 2016-20 regulatory period, and our forecast for the 2022-26 regulatory period. This figure shows that we are forecasting a reduction in net capex over the next regulatory period, with total capex falling by over a fifth (21%).

Figure 9-2: Net capex, actual and forecast 2016 to 2026 ($m, real 2021)



Note: Jan to June 2021 is presented on an annualised basis.

Importantly, our capex proposal meets our customers' expectations and evolving needs, which include:

- access to safe, reliable and affordable electricity;
- a better customer experience when interacting with our business (for example connections and outage notification);
- more accurate and timely information; and
- an ability to leverage their investments in DER.

25 Power of Choice was a package of National Electricity Market (NEM) reforms designed to give consumers more options and control of the way they use their electricity and manage their electricity expenditure. AEMO worked with industry to implement these changes by 1 December 2017, and the Power of Choice program has now concluded.

We are confident that we understand our customers' expectations and evolving needs as we have listened to our customers and have undertaken extensive consultation with them, including through:

- the Customer Forum, whom we have agreed specific aspects of our capex proposal with – see section 9.7;
- inviting responses from customers to our Draft Regulatory Proposal;
- deep dive workshops; and
- other engagement programs.

The table below presents our annual forecast capex over the 2022-26 regulatory period by expenditure category. While our proposed safety capex is lower when compared to the current regulatory period, this is due to us completing the first two tranches of the REFCL program by 1 May 2021. Our commitment to safety nonetheless remains steadfast. With this in mind, we have maintained our previous approach of reporting our safety related capex as a separate category of expenditure. However, to comply with the AER's data requirements/templates, we have also provided our annual forecast in accordance with its preferred categories.[26] The tables below show our forecasts under both these categorisations.

Table 9-1: Annual and total capital expenditure forecast, AusNet Services categories

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Replacement	143.0	150.9	151.3	128.6	106.9	**680.7**
Safety (incl. REFCL)	49.8	39.7	37.4	53.6	69.5	**249.9**
Customer Connections	113.6	112.0	110.7	112.3	113.8	**562.4**
Augmentation	19.6	22.0	19.4	15.7	15.4	**92.2**
ICT	48.1	34.3	38.9	30.2	29.6	**181.1**
Other non-network	10.4	7.7	7.2	10.5	18.0	**53.8**
Total gross capex	**384.6**	**366.6**	**364.8**	**350.8**	**353.3**	**1,820.2**
Customer contributions	72.3	70.4	68.8	69.9	70.8	**352.3**
Total net capex	**312.3**	**296.2**	**296.0**	**280.9**	**282.5**	**1,467.9**

[26] When discussing our capex proposal we use our preferred categorisation as per Table 9.1 unless otherwise stated.

Table 9-2: Annual and total capital expenditure forecast, AER preferred categories

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Replacement expenditure	148.5	150.7	148.0	132.0	123.6	**702.8**
Connections	107.0	105.6	104.3	105.7	107.0	**529.6**
Augmentation expenditure	43.4	41.3	39.1	44.9	47.3	**216.0**
Non-network	55.9	39.7	44.1	38.9	46.0	**224.6**
Capitalised network overheads	25.1	24.7	24.7	24.7	24.7	**123.7**
Capitalised corporate overheads	4.8	4.7	4.7	4.7	4.7	**23.4**
Total gross capex	**384.6**	**366.6**	**364.8**	**350.8**	**353.3**	**1820.2**
Customer contributions	72.3	70.4	68.8	69.9	70.8	**352.3**
Total net capex	**312.3**	**296.2**	**296.0**	**280.9**	**282.5**	**1467.9**

The figure below illustrates the composition of our investment program by showing how every $100 of capex is allocated across our capex categories in the 2022-26 regulatory period.

Figure 9-3: For every $100 capital investment on our network….

$33	Replacing aging assets	Replacing assets at the end of their life to maintain network reliability
$15	Safety	Safety expenditure including ensuring network safety in our high risk bushfire areas
$28	Connecting new customers	Connecting new customers to the network (excluding customer contributions)
$7	New network capacity	Providing required network electricity delivery capacity to meet growth in customers and demand. This ensure we meet peak demands on our network
$10	Information technology	IT supporting sound business innovation and operation including cyber safety
$3	Smart meter & Comms	AMI services used by the distribution businesses
$4	Other capitalised costs	A range of non-network expenditures such as vehicles, property and tools

As indicated above, repex and connecting new customers make up over 60% of our proposed capex. By contrast, augmentation is one of the lowest capex categories at 7% of our total proposed capex.

9.4 Customer preferences and feedback

The Customer Forum encouraged us to place a much stronger focus on the potential impact of our operational and investment decisions on our customers. We have responded to this and this proposal is better as a result.

While Part I of our proposal provides a detailed description of our customer engagement program and the feedback received, this section briefly recaps the key customer feedback we received on our capex proposals.

Electricity prices remain a key concern for all customers, both in terms of affordability and value for money. Around two thirds of customers consider that with electricity prices having increased in the past two years it provides poor value for money (see Chapter 3).

Research confirms that customers consider that having a reliable, continuous supply of electricity is the most important service we can provide. Business customers feel particularly strongly about that. Having a reliable supply of electricity is closely associated with customers' personal values of trust, honesty and family.

Feedback indicates that customers are not prepared to accept lower levels of reliability (including more blackouts), but at the same time do not want to pay more for their energy. In addition, to avoid higher prices or increased outages, most customers would prefer to reduce their electricity use. The Customer Forum, through its own research, also identified the importance of maintaining current levels of reliability.

Based on quantitative research we conducted, service disruptions once a year are acceptable to the majority of customers, but outages every four to six months are only acceptable to less than a third of customers. Irrespective of the frequency of outages, we are also aware that outages cause real pain for our business customers of all sizes. For example, in a survey of small to medium businesses, a reliable energy supply and energy costs were in the top three key issues/challenges facing business.

'Control' is a key issue for our customers. Specifically, through customer engagement we have found that there is strong concern regarding any possibility that limits will be placed on customers' solar exports. For example, research found that 80% of customers would be dissatisfied if restrictions to export DER were in place. Similarly, research found a strong preference for voluntary rather than automated demand response programs, again emphasising the desire of our customers to retain control.

Our engagement with customers, including through the Customer Forum, has allowed us to distil customer feedback into five key priorities:

- Delivering basic services – "deliver on the basics";
- Keeping customers informed – "keep me posted";
- Affordable services – "affordable for me";
- Adaptability – "be ready for the future"; and
- Safety – "always safe".

The figure below shows these priorities and highlights how we have taken into account customer feedback when developing our proposals.

Figure 9-4: Key priorities underpinning our capex plans

Deliver on the basics	***Keep me posted***	***Affordable for me***	***Be ready for the future***	***Always safe***
Ensure customers have a consistent and reliable supply of electricity (including new customers)	*Any changes to supply must be preceded by clear and simple communication and delivered in a timely manner*	*Make the necessary upgrades to the network to meet my expectations and control expenditure and charges*	*Make sure customers can connect DER and apply modern technologies to manage their usage efficiently*	*Ensure that the network always operates without any undue risk to the safety of the community*

For each of the capex categories we discuss in this chapter, we provide examples of the choices and trade-offs that we propose to make in response to this feedback. For example:

Our proposed ICT program includes investments in CIS and Outage Management systems that will help us address customers' expectations around timely and accurate provision of information (particularly in relation to outages) as well as provide more tailored customer services.

Customer research revealed high levels of interest in installing DER[27] and a general view that the cost of DER connections be shared across all customers.[28] To ensure we meet customers' expectations that they maximise the value of their DER investment in the 2022-26 regulatory period, we are proposing a modest level of capex to:

- increase our ability to accommodate increasing demand for DER; and
- increase our customers' ability to export energy where it is economically efficient to do so, and benefit all our customers.

9.4.1 Feedback on our Draft Regulatory Proposal

In February 2019, we published our Draft Regulatory Proposal and sought feedback on all aspects of it, including our capex proposal. We also ran "deep dive" workshops on our repex, DER and ICT forecasts. Participants in these workshops included customer advocates, members of the AER's Consumer Challenge Panel (CCP), AER staff and the Customer Forum.

Our deep dive workshops and subsequent engagements with the Customer Forum were very productive and allowed us to listen stakeholder views, share information address stakeholders' views and explain the options we had considered in developing our proposals.

In response to our Draft Regulatory Proposal, we received submissions from the:

- Energy Users Association of Australia (EUAA);
- CCP-17;
- South Australian Council of Social Services (SACOSS); and
- Energy Consumers Australia (ECA).

We also received several comments via an online form linked to social media posts promoting the Draft Regulatory Proposal. These posts emphasised:

- that more investment to enable customers to export solar energy/DER would be appropriate;
- that the costs associated with solar/DER should, in general, be borne by all customers; and
- the importance of effective communication with customers.

AER staff also issued a guidance note outlining the areas that the Customer Forum (and us) may wish to give further consideration.[29] This was a useful addition to the discussion, as it helped us refine our proposal as well as have more productive discussions with the Customer Forum.

The feedback we received from responses to our Draft Regulatory Proposal and through our deep dive workshops, and how we have responded to that feedback is summarised in the table below (and in more detail in Chapter 4).

27 This research indicated 60% of non-solar customers were interested in installing DER in the future.

28 The rationale being that DER will be widespread and that non-solar customers will be able to share in the expected benefits. This view represents a cultural shift. When solar was less common, this was not our customers' view.

29 AER, Staff guidance note 9 (available at: https://www.aer.gov.au/system/files/AER%20Ausnet%20Services%20trial%20-%20Guidance%20note%209%20-%20draft%20proposal%20and%20interim%20engagement%20report%20-%20March%202019.pdf – accessed 9 July 2019).

Table 9-3: Feedback on the Draft Regulatory Proposal

	Comment	Our response
ICT capex	The EUAA did not consider that having an ICT proposal in line with previous periods was a reason to support it. It sought a more robust analysis of the benefits of the proposed spend, preferably on a total expenditure basis.	Section 9.12 outlines the justification for our ICT capex forecast, including how we developed our forecast, how it aligns with our customers' preferences, and the network and customer benefits that each ICT program delivers.
	The AER noted our proposal for an opex step change due to the transition to cloud-based software. It suggested that we set out how any step change will be offset by lower levels of ongoing capex.	Section 9.12 outlines the approach we have taken with respect to ICT capex, including how it will decline should we fully transition to cloud-based ICT solutions. Chapter 10 explores our opex proposal, including ICT step changes and our efficiency proposal.
	At the ICT deep dive workshop attendees wanted more information on how we developed our proposal, the expected customer benefits and total (capex and opex) ICT expenditure.	Thirteen ICT project briefs form part of our proposal. These briefs provide detailed information on each project, including expected customer benefits. Our Technology Strategy also provides information on Deloitte Consulting's involvement in developing our ICT proposal and its satisfaction with the approach we adopted to develop our proposal. Section 9.12 also outlines our approach to ICT capex.
	The ECA considered that more information on the drivers of ICT expenditure and the expected consumer benefits was appropriate.	As above.
Total capex	The EUAA indicated that it will await the AER's analysis of our proposed capex through the repex model and other assessment techniques before giving its position on our proposal.	Section 9.8 considers our repex forecast and how it benchmarks favourably with the AER's repex model. We note that this model suggests that our forecasts are prudent and efficient.
	The ECA was concerned with the credibility of our capex forecast, especially with respect to repex. It noted that the accuracy of forecasts plays a big role in the affordability of network investment and that it was	As discussed in section 9.5, we derive our forecasts using different inputs and assumptions. Our forecasting approach (section 9.6) also involves us preparing forecasts for each capex category, explaining the drivers of our proposed spend, outlining our

	Comment	Our response
	important for building and maintaining trust.	projects/programs and validating its overall prudency and efficiency.
Deliverability of the capex program	The CCP expressed concern with the deliverability of the proposed capex program.	We are confident in our ability to deliver our proposed capex program, notwithstanding that it involves a number of zone rebuilds. We have demonstrated in the current regulatory period our ability to deliver significant investment, including major safety programs (REFCL). For example, most of the work associated with REFCL is completed in Tranche 1 and 2, which we expect to be complete prior to the start of the 2022-26 regulatory period. Our proposed net capex for the 2022-26 regulatory period is also 21% lower than the actual/expected cape we expect to deliver in the 2016-20 regulatory period.
Major repex projects	The CCP noted that: • it expects more technical rigour in the assessment of major repex projects in the formal regulatory proposal (relative to the information presented to the Customer Forum); and • we should incorporate the features of the approach set out in the AER's Industry practice application note for asset replacement planning.	The information presented to the Customer Forum was largely designed to facilitate discussion of price/reliability trade-offs at the portfolio level. As such, it does not reflect the full sophistication of the economic model and inputs that we have used to determine the scope and timing of each project. The planning reports submitted with this proposal set out our economic assessment framework, which is largely consistent with the AER's Industry practice application note, including the cost-benefit assessment methodology we have applied, the options considered (including the base case and non-network options), how each category of risk has been quantified, the optimal timing of the proposed preferred solutions etc.
	At the Repex Deep Dive workshop, attendees sought additional evidence to demonstrate that each proposed project is economically efficient, and that demand management or other	The planning reports submitted with this proposal include consideration of options such as demand management and embedded generation network support to defer or replace network assets.

	Comment	Our response
	non-network solutions were considered.	
	At the Repex Deep Dive workshop, the AER questioned whether our repex projects are designed to improve or maintain reliability.	By replacing a poor condition asset with a new asset, the major repex projects will restore and improve <u>local</u> reliability. However, as reliability elsewhere on the network is expected to decline, due to deteriorating assets not being replaced, <u>overall</u> reliability will be maintained. This is consistent with the NER requirement that networks are funded to maintain current reliability.
	The AER noted that: • it would be informative to see customer preferences if the bill savings from the deferral of some projects were shared only between those customers whose supply would be impacted, rather than across all customers; • there could be benefit in undertaking cost benefit analysis for each of the projects being considered; and • there was scope to improve how we explained expected cost reductions and reliability impacts of deferrals.	The AER's research proposal does not reflect the pricing arrangements by which major repex project costs are recovered. While such research would provide some insight, this would be from a theoretical rather than practical level. Economic modelling and a planning report (with benefit analysis demonstrating that our proposal is the preferred solution) support our repex proposal. This information accompanies this proposal. We also note that the portfolio approach to repex was discussed with the Customer Forum and represents a mechanism that we consider makes engagement on this issue easier. In addition, following additional, robust engagement, the Customer Forum has agreed our repex proposal. As part of this, expenditure/risk trade-offs were made, as were decisions that would look to address customers' affordability concerns.
	The ECA expressed doubts about the accuracy of our repex forecasts and its deliverability. It suggested that more technical information was required if an informed decision on the proposed investment was to occur. However, it also recognised that some of this information may be better suited to	Since the publication of the Draft Regulatory Proposal we have had further engagement with the Customer Forum on various aspects of our capex proposal, including with respect to repex (section 9.7). We agree with ECA that a (draft or final) regulatory proposal is better suited to providing more detailed

	Comment	Our response
	being included in a regulatory proposal.	repex information. For example, section 9.8 provides more information on the different elements of our proposed repex, including how it aligns with the AER's repex model.
Proactive replacement of SWER lines in Codified areas	At the Repex Deep Dive workshop, attendees asked about the level of community engagement undertaken for the proposed program to proactively replace SWER lines in areas Codified Areas.[30]	The proposed SWER replacement program continues the Powerline Replacement Fund (PRF) program, which was recommended by the Powerline Bushfire Safety Taskforce (PBST) following the Victorian Bushfires Royal Commission (VBRC). The PBST and VBRC undertook extensive community engagement prior to recommending replacements of conductors. This engagement revealed strong community sentiment that SWER lines should be replaced by safer assets, such as covered conductors or undergrounded cables. As it is unlikely that the community's views on safety have changed, we have relied on the extensive engagement already undertaken and have not carried out further engagement on this issue.
Augex projects	The AER outlined the information and factors it will use to assess the proposed projects, including demand forecasts, options considered and load transfers. It did not provide any specific feedback on our proposed augex.	The planning reports submitted with this proposal detail our consideration of the relevant factors in our economic assessment framework and model. In addition, as a condition of our negotiations with the Customer Forum, our framework was subject to an independent engineering review. This review found that the inputs, assumptions and methodology used to develop our proposal were robust.
	The CCP noted that the final assessment of our proposed augex projects will be carried out by the AER. It also noted that the proposals as expressed in the Interim Engagement Report are consistent	We welcome the views of the CCP.

30 A Codified Area is an area defined in the Electricity Safety (Bushfire Mitigation) Regulation 2013 as an 'electric line construction area'. These are prescribed geographical areas of highest fire loss consequences where new or replacement powerlines must be built using insulated cables.

	Comment	Our response
	with the long-term interests of consumers, and are prudent in respect to the proposed investment.	
	The SACOSS expressed concern with some of the analysis considered by the Consumer Forum and the need for the AER to scrutinise our proposal.	The New Reg process, including our partnership with the Consumer Forum, has been instrumental in shaping our proposals. However, the AER still undertakes its formal assessment of our proposal.
	The ECA noted that the forecast for growth capex is steady and the two major growth projects at Doreen and North Clyde were to be negotiated with the Customer Forum. However, it also noted that the remainder of our augex program had not been justified and that this was a significant gap.	The planning reports submitted with this proposal detail how we have considered the relevant factors in developing our capex proposal. The AER will, when undertake its formal assessment of our proposal.
	The CCP noted that our draft proposal included $4.3milion for network sensors related to our DER proposal. The CCP questioned what these sensors were for.	We have removed separate proposal for these sensors from our regulatory proposal. The necessary additional equipment is part of the DENOP proposal and this separate item was a double counting of expenditure in the draft proposal. We require additional sensors at the distribution transformer to monitor power quality and flow on a real time basis as an input into our smart networks system. Our smart meters provide a delayed data flow so some additional data is necessary.

9.5 Key inputs and assumptions

The key inputs and assumptions underpinning our capex forecast are:

- Asset Management Strategy (AMS);
- Demand forecasts and customer numbers;
- Value of Customer Reliability (VCR);
- Safety and other obligations;
- Quality of supply;
- Project cost estimates and unit rates;
- Cost escalators;
- Overheads;
- Future trends and developments; and

- Electricity Network Transformation Roadmap (ENTR).

Further details on these inputs and assumptions are set out below. While these inputs and assumptions are reasonable, they may not eventuate. Our actual capex requirements may therefore differ to the forecasts presented in this proposal. Where our actual capex does vary from our forecasts, the regulatory framework ensures that the associated upside and downside risks are shared fairly between our customers and us.

9.5.1 Asset Management Strategy

Our AMS is central to our processes for managing our electricity distribution assets and delivering quality services to customers and value to our shareholders.[31] It sets out the medium-term strategic actions required to achieve regulatory and business performance targets, which we implement via the programs of work shown in the five-year Asset Management Plan we produce each year.

The strategic actions set out in the AMS focus on meeting our asset management objectives, which are to:

- comply with legal and contractual obligations;
- meet customer needs;
- reduce safety risks;
- be future ready; and
- maintain network performance at the least sustainable cost.

The AMS is underpinned by the regulatory and commercial imperatives of delivering efficient cost and service performance. It recognises that cost and service efficiency does not mean lowest possible cost, nor does it mean guaranteed reliability. Instead, efficiency requires the costs and benefits of all expenditure decisions to be weighed against one another. A key element in this economic assessment is the consideration of risk management for asset performance and network reliability.[32]

The AMS has the following key functions:

- To set the framework for our holistic approach to managing network assets, and in so doing establish the linkages with and between the underpinning detailed strategies, processes and plans.
- To provide context for management strategies, by considering the demand for network services, the condition of network assets and expected trends into the future. It also has regard to the network augmentation planning process.
- As the output of a strategic assessment process, the AMS also sets out the key asset management focus areas and associated strategies to manage each asset class. It provides authoritative guidance for the development of asset management works programs. The information presented in the AMS also extends to longer-term expectations for technological advancement of network assets, the functionality of the network and evolution of management approaches. As such, the AMS is a key input to our asset management plans and capex forecasts.

Our AMS was also the first of any Australian electricity network to achieve certification under the best practice International Asset Management Systems ISO55001 Standard. In addition, in the most recent ISO55001 certification audit of our asset management systems we equalled or set new best

31 The AMS is provided in the supporting documents that form part of this submission.

32 Section 9.6 has more information on our approach to the economic assessment of projects and programs.

practice benchmarks for 18 out of 24 aspects of asset management relative to our Australian and New Zealand peers. The certification audit concluded:

> *Based on the assessment information, there are not many ISO55001 clauses where the AusNet Services asset management system does not currently demonstrate, or provide leading edge business understanding, structure, people and culture, planning and delivery of work with appropriate systems and processes, many of which are highly sophisticated.*

9.5.2 Demand forecast and customer numbers

The key assumption for the 2022-26 regulatory period is that peak demand will experience moderating growth.

In relation to customer numbers, we are expecting strong urban growth rates to continue over the 2022-26 regulatory period. This is despite the overall slowdown in the housing market. While the strong urban growth is not contributing to a significant increase in system peak demand, it is driving connection-related capex.

Where actual outcomes differ from our assumptions, the regulatory framework's design ensures we share these risks with our customers.

Our capex forecast has also been developed to take into account any changes in demand due to our proposed tariff structures. For customers consuming 40 MWh per year or less, we will look to assign new connections, upgrading customers and electric vehicle customers (once a register has been established) to a Victorian-wide time of use tariff.

Whether, and the degree to which, this will materially change consumption behaviour will depend on factors including whether the price signal is ultimately reflected in the customers' retail bill. The sensitivity analysis undertaken for each proposed major capex project is an appropriate means of accounting for any potential change in consumption behaviour due to tariff structure changes.

The impact of current cost reflective tariffs on large customers consuming more than 40MWh per year is reflected in the demand forecasts that underpin our capital program, as behavioural impacts are reflected in historical actual demand, on which the forecasts are based. The Critical Peak Demand tariff, in particular, has had material impacts on peak demand days due to reductions in industrial load in the past.

Further information on our demand and customer number forecasts is available in Chapter 7.

9.5.3 Value of Customer Reliability

The VCR estimates the value the community places on a reliable electricity supply. This is an important input to determining when augmentation and asset replacement is economically justified.

In Victoria, the Australian Energy Market Operator (AEMO) has traditionally estimated the VCR. AEMO's most recent estimate of VCR occurred in 2014. Since then, where we have used the VCR, we have indexed AEMO's estimate to account for inflation.

However, following the introduction of a new Rule[33], the AER was required to estimate the VCR every five years, with its first estimate required on or before 31 December 2019. On 18 December 2019, the AER published its first VCR values.[34]

33 Clause 8.12(g).

34 AER, Values of Customer Reliability, Final report on VCR values, December 2019.

Given the timing of the AER's VCR publication, we have used AEMO's appropriately indexed 2014 estimate in preparing this proposal. We will, however, carefully consider the AER's VCR estimates and may revise our capex forecasts as part of our revised proposal.[35]

9.5.4 Safety and other obligations

Our expenditure plans for the 2022-26 regulatory period reflect our commitment to achieving compliance with our safety and other obligations. As such, we invest to meet the following obligations:

- Clause 3.1 of the Victorian Electricity Distribution Code (the Code), requires us to manage our assets in accordance with the principles of good asset management. Under this provision we must develop and implement plans for the management of our assets to minimise risks associated with the failure or reduced performance of assets.
- Clause 5.2 of the Code requires us to use best endeavours to meet customers' reasonable expectations of supply reliability.
- Section 98 of the *Electricity Safety Act 1998*, which requires us to design, construct, operate, maintain and decommission our network to minimise as far as practicable:
  - the hazards and risks to the safety of any person arising from the network;
  - the hazards and risks of damage to the property of any person arising from the network; and
  - the bushfire danger arising from the network.
- The *Electricity Safety Act 1998*, which requires us to lodge an Electricity Safety Management Scheme (ESMS) and annual Bushfire Mitigation and Vegetation Management Plans with Energy Safe Victoria (ESV).

In addition, in May 2017, amendments to the *Electricity Safety Act 1988* came into effect. In relation to our distribution area, the Act requires that:

- Each polyphase electric line originating from 22 prescribed zone substations must comply with performance standards specified in the regulations by 1 May 2023. These performance standards can only be met by installing REFCLs, which is a technology not previously used for bushfire risk reduction anywhere in the world.
- Each electrical line that meets the prescribed specifications, and which is of at least four consecutive spans, must be covered or undergrounded.

By 1 May 2021, we expect the second tranche of the REFCL program to be complete. For the 2022-26 regulatory period, our forecasts include the expenditure to complete Tranche 3 of the REFCL program. We have also made provisions for additional further expenditure to ensure the ongoing compliance at our Tranche 1 and Tranche 2 sites. Importantly, our forecasts assume that the timeframes and scope for the final tranche of the REFCL program (see section 9.9) will not change.

Our compliance obligations, which are critical to providing a safe and reliable service, do nonetheless have the potential to impose significant costs on our customers. For the 2022-26 regulatory period, our network capex forecasts reflect the assumption that these obligations will be

[35] As our major projects go through an internal business case approval process, any updates to the VCR will be appropriately captured in our processes. This means that our management will be provided the opportunity to, among other issues, confirm if a project remains in line with business strategies and will achieve the benefits expected, and determine if the project should continue, slowdown or stop.

ongoing and there will be no change to our current safety or other obligations, including our obligations in relation to bushfire mitigation.[36]

9.5.5 Quality of supply

The Code sets out quality of supply standards that apply to Distributed Network Service Providers (DNSPs) in Victoria in relation to the following parameters:

- voltage standards;
- power factor;
- harmonics;
- inductive interference;
- load balancing (negative sequence voltage); and
- flicker.

Our expenditure plan is designed to ensure we maintain power supply quality within the limits specified for each parameter in accordance with the Code and the relevant standards, recognising that the strong uptake of rooftop solar generation creates quality of supply issues.

We note that the Essential Services Commission (ESC) is currently reviewing the Code to ensure that it remains fit for purpose. In a recently published issues paper, the ESC highlighted its openness to reviewing current voltage standards to support how customers are connecting and using the grid.[37] In our response to that paper, we supported adopting an industry-recognised Australian Standard for voltage management (AS 61000.3.100) as this:

- recognises that customers' inverter based energy systems generate electricity at higher voltages than permitted by the current Code; and
- would allow greater uptake and installation of DER.

9.5.6 Project cost estimates and unit rates

Our project cost estimates are prepared as part of a standardised approach to developing, managing and reporting projects and programs of works, as outlined in our Project Cost Estimating Methodology (see Appendix 9A). This approach means that:

- project cost estimates are prepared in accordance with specific project execution procedures and practices, including reviews and a sign-off process based on consistent, clear lines of responsibility and accountability;
- consistent costing standards and controls are applied when we develop our project cost estimates; and
- our capex forecasts are prepared on a P50 basis, which is an estimate that has a 50% confidence factor of not being exceeded by cost at project completion.

36 The regulatory information notice checklist provided to the AER as part of this submission requires us to provide information on all step changes proposed. For capex, we have interpreted step changes to be safety programs with a compliance driver in the forecast period. Forecast costs for these programs are generally due to an "externally imposed change in the scope or scale of required capex". Capex programs that satisfy this definition include: (1) Replacement of bare SWER conductor in Codified Areas; (2) Tranche 3 REFCL Construction, Testing and Commissioning; and (3) Augmentation to address the capacitive current seen by REFCL's. Section 9.9 explores our proposed safety programs in more detail. As noted, we have assumed that these obligations will be ongoing (recurrent) and there will be no change to our current safety or other obligations.

37 This issue paper is available here: https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-policies-and-manuals/electricity-distribution-code/electricity-distribution-code-review-2019#toc--issues-paper (accessed 16 September 2019).

The primary basis of the unit rates we use to develop our forecasts is the rates incurred in recently completed work. Our rates reflect the efficient cost of delivering similar projects in our network area, recognising that we:

- deliver our projects and programs using an efficient combination of competitively tendered and internal resources; and
- have established, by competitive tender, pre-qualified panels of design and installation service providers to safely design and install works for major projects such as zone substation rebuilds.

Our forecast unit rates and their basis are at Appendix 9B (Unit Rates).

9.5.7 Cost escalators

Our capex forecasts reflect expected changes in the cost of labour and materials during the regulatory period. As with any other commercial business, the price we pay for labour and materials is determined by competitive national and international markets.

The current outlook for input costs is for moderate growth. We expect (internal and external) labour costs to grow at the same rate, slightly above Consumer Price Index (CPI), while we expect material costs to be flat in real terms.

Further information on our labour escalation forecasts is available in Chapter 7.

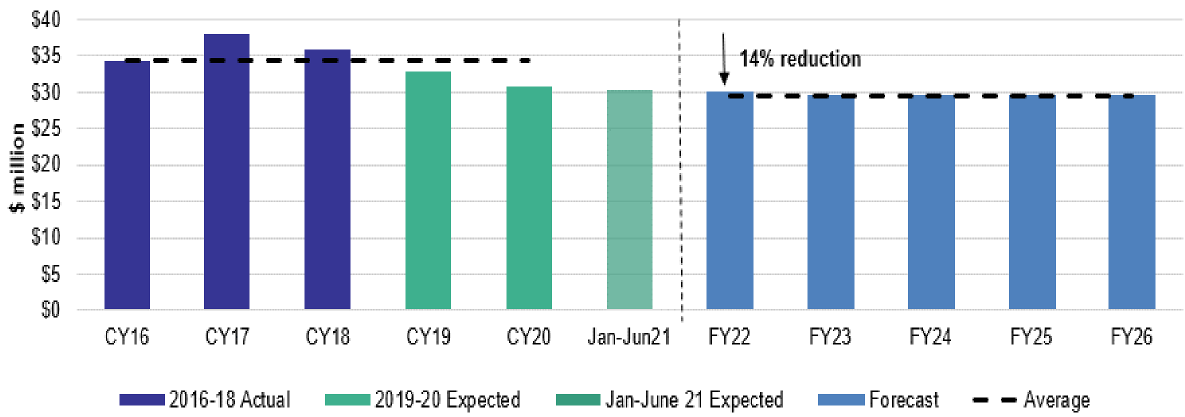
9.5.8 Overheads

The basis of our forecast pool of capitalised overheads for the 2022-26 regulatory period is a forecast of total corporate and network overheads that we have capitalised in accordance with our capitalisation policy.

Importantly, our capitalisation policy reflects the change made in April 2019 to accounting standard AASB 16, wherein operating leases became 'Right to Use' (capital) assets. This change looks to ensure comparability of a company's profitability regardless of whether it chooses to purchase or lease property, plant and equipment. Consequently, our operating leases are now capex, not opex.

Our forecast of the fixed pool of overhead costs is, on average, $29.6 million per annum ($2021) over the 2022-26 regulatory period (see figure below). This is a 14% reduction compared to the annual average actual/expected overheads in the current regulatory period of $34.4 million ($2021) and reflects our continued focus on efficiency improvements and cost reductions. Further information on our efficiency improvements, which will result in lower prices for customers, is available in Chapter 10.

Figure 9-5: Capitalised overheads ($m, real 2021)



Note: Jan to June 2021 is presented on an annualised basis.

Consistent with internal accounting practices, we allocate our forecast capitalised overhead pool separately to network capex, ICT capex and connections capex. This approach, which produces the most accurate attribution of overhead costs, results in average overhead rates of approximately 11% for network capex, 9% for connections capex and 8% for ICT capex.

9.5.9 Future trends and developments

We have made several assumptions regarding future trends and developments when preparing our capex forecasts, including:

- We need to continue to facilitate outcomes that our customers want, while also addressing affordability concerns. This includes improving customers' experience, particularly with respect to providing timely information about outage restoration times and more tailored customer service. While our ICT proposal includes investments in CIM systems that will allow us to do this, and we have proposals that will enable customers to maximise the potential value from DER (another key customer expectation), this is an evolving area and we must be ready to listen and to take action, including by potentially re-prioritising projects.
- Technological developments will continue to shape customers' use of the distribution network, with increased penetration of small-scale solar generation. Other technologies, particularly small-scale battery storage and electric vehicles, will continue to grow at modest rates based on current market and policy settings. Any policy announcement that increases expected battery storage or electric vehicle uptake will require us to undertake further modelling and potentially revisit our forecast (as part of our revised proposal). We are also proposing a prescribed pass-through event to manage any material cost increases associated with electric vehicle uptake (see Chapter 17).
- Victorian DNSPs currently have the exclusive right to provide smart meters to residential and small business and commercial customers. If our assumption that this exclusivity does not continue across the next regulatory period, we will face higher costs to access the near real-time network information needed to improve response times, fault detection and asset performance that our customers enjoy. Any additional cost may need to be passed-through to our customers.

9.5.10 Electricity Network Transformation Roadmap (ENTR)

In April 2017, Australia's national science agency, CSIRO, and the peak national body representing gas distribution and electricity transmission and distribution businesses in Australia, Energy Networks Australia, released the ENTR.[38]

The ENTR calls attention to the fact that:

- Australia's electricity networks are facing complex challenges that impact the economic efficiency and technical stability of the system;
- Australia's electricity system will require expenditure of almost $1,000 billion by current service providers, new entrants and customers by 2050; and
- the type and scale of benefits gained from this unprecedented investment will vary greatly, depending on decisions made during the next 5-10 years.

[38] ENA and CSIRO, Electricity Network Transformation Roadmap, available at: https://www.energynetworks.com.au/electricity-network-transformation-roadmap (accessed 19 August 2019).

The ENTR provides detailed milestones and actions to guide an efficient and timely transformation through to 2027, which has guided aspects of our business plans and this proposal. For example, the Customer Forum process is integral to gaining the improved levels of customer trust and engagement that is vital to achieving the more customer-oriented energy future envisaged in the ENTR. Equally, our proposed innovation program (see Chapter 11) includes a stand-alone power systems trial, which the ENTR recognises will be an important alternative for traditional energy delivery models in the future.

9.6 Forecasting approach

In sections 9.8 to 9.13, we consider the forecasts for each capex category, the drivers of our proposed capex, our proposed projects and programs, and our approach for validating the prudency and efficiency of our proposal.

This section provides an overview of our forecasting approach and focuses on four elements:

- Economic Assessment of Projects and Programs, which is key to ensuring that our plans are prudent and efficient;
- Network Support, which involves the active consideration of non-network solutions;
- Top-down review, which recognises that as ‘bottom-up’ forecasting may overstate expenditure requirements, a top-down review is required to ensure the forecast expenditure reflects only prudent and efficient costs; and
- Benchmarking, which tests our forecast plans by examining our performance against our peers.

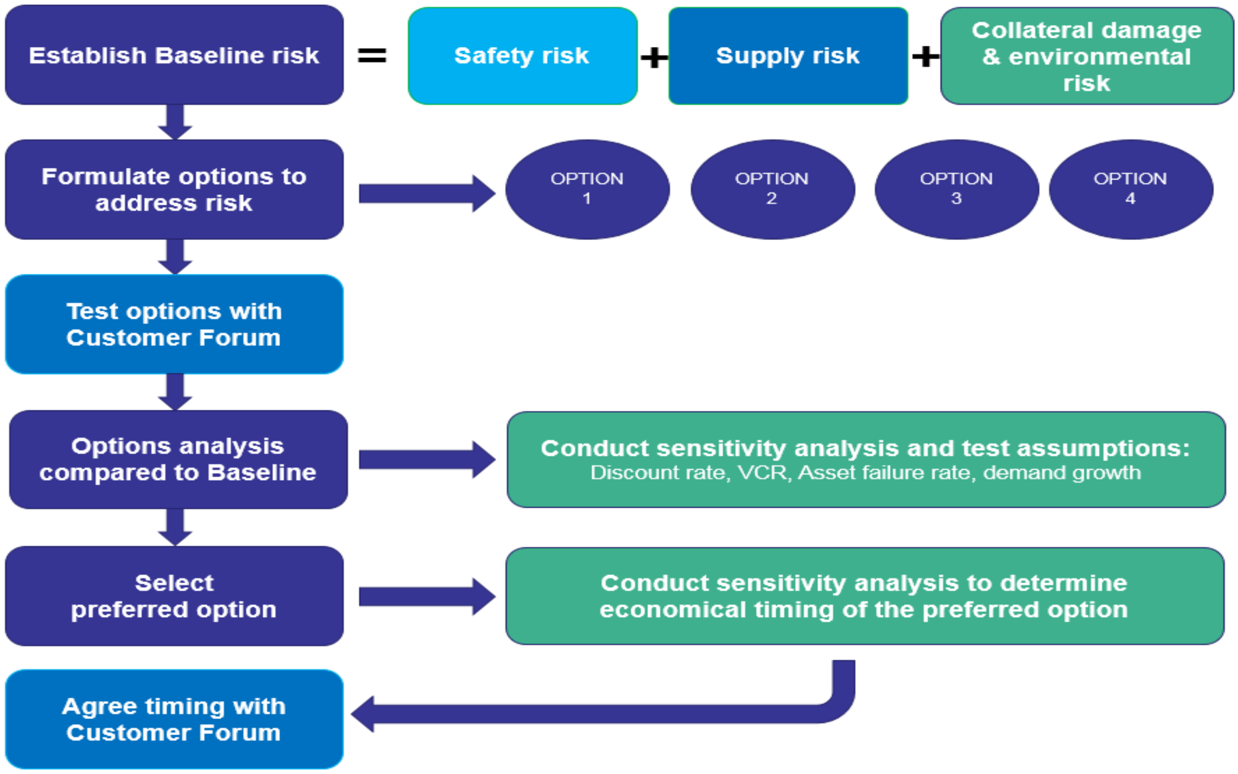
9.6.1 Economic assessment of projects and programs

Our capex proposal meets our customers’ expectations and our compliance obligations prudently and efficiently. We identified projects and programs of work proposed for the next regulatory period through planning studies and analysis conducted as part of developing asset management strategies, combined with our customer engagement program.

To ensure that our capex plans are prudent and efficient, we conduct economic assessments on proposed projects and programs of work. This also ensures that we deliver the best value for money. As discussed in section 9.7, we have also engaged with the Customer Forum (and other stakeholders) to ensure that our proposal reflects the “voice of the customer”, including for augex and repex major projects.

The figure below provides an overview of the approach we used for the economic assessment of all the projects and programs included in this proposal.

Figure 9-6: Economic analysis approach



Each project and program is authorised through a business case, which contains an evaluation of the options considered to address the identified risks and demonstrates the efficiency of the selected option. When we are looking to address an identified network need, we consider all credible options, including non-network options.

As part of our quality control measures, each business case is reviewed by engineering and financial managers against relevant asset management decision criteria. Assuming the business case passes this assessment, it is authorised by a duly authorised manager with authority to approve expenditures.

The scope and content of each business case will depend on the nature of the assets and the key driver(s) for the proposed expenditure. For example, a program may be driven by our obligations under the *Electricity Safety Act* (section 83B or Part 10), which requires us to minimise safety risks 'as far as practicable'. In practice, this obligation means we must take steps to improve network safety unless the costs of doing so are disproportionate to the benefits.

As such, the business case analysis for a safety-driven project or program will be different to reliability-driven projects or programs, where the project or program may still proceed if the benefits exceed the costs.

The analysis undertaken for each business case depends on a range of factors, including:

- the expenditure drivers;
- asset criticality;
- safety and risk assessment;
- volume, nature and value of assets;
- availability of information on asset condition and failure probability; and
- applicability of models, such as repex modelling.

Our assessment approach is different for 'high volume, low value' assets and 'low volume, high value' assets. The principal difference is that population and sub-population modelling is required for large volume assets, whereas we undertake asset specific analysis for low volume assets. The overall objective, however, remains the same in each case – to deliver the lowest total cost service to our customers by ensuring that we evaluate the costs and benefits of alternative expenditure options using a robust economic assessment framework.

We have applied the approach described above when determining our proposed project- and program-level expenditure forecasts. Further information on our approach is available in the planning reports and plant strategies accompanying this proposal, and the underlying models used to inform these documents can be provided if requested. For each of the capex categories discussed later in this chapter, we provide further information on the forecasting approach adopted, and explain why we are confident that our proposed expenditure meets the Rules requirements.

Importantly, the approach we use to develop our capital expenditure forecast is consistent with the approach taken for budgetary, planning and governance processes used in the normal running of our business.

In addition, as part of the quality assurance steps that we take to ensure that our capex forecast is free from error, we:

- review historic rates and volumes;
- have competitively tendered contract conditions; and
- undertake internal reviews and have established governance processes across Finance, Service Delivery and Asset Management divisions.

9.6.2 Network support

Network support refers to the suite of non-network solutions and demand management techniques used to manage risk and improve the performance of the distribution network. These services, which we generally treat as opex, include:

- services provided by embedded generation;
- embedded storage;
- tariff strategies; and
- customer demand response.

We may also enter into contracts for network support services to defer capex projects, reduce energy at risk levels or respond to network contingencies. We routinely consider non-network options as part of the regulatory investment test for distribution (RIT-D) assessment framework.

Growth of non-network solutions is encouraged as it can provide the lowest cost solutions for our customers. In this regard, our award-winning Network Innovation team conducts trial projects, evaluates options and provides input to network planning processes.[39] In addition, our Network Planning team considers the scope for embedded generation and demand management options as part of the network planning process. We support these activities by:

- maintaining a register of demand side suppliers; and
- developing and publishing our Demand Side Engagement Strategy.

The following initiatives are recent examples of some of the innovative actions we have taken to promote demand management solutions:

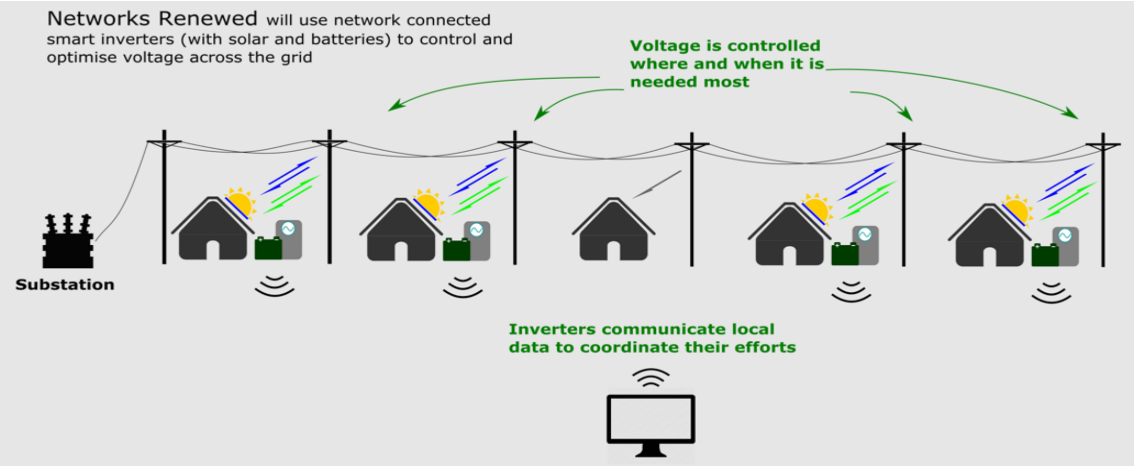
- **Community Mini-Grid Trial** – To test a range of future non-network solutions, we successfully built a suburban community mini-grid in Mooroolbark utilising Demand Management Innovation Allowance (DMIA) funding. This project was a joint winner of the Clean Energy Council's Innovation Award in 2017. The trial successfully separated and reintegrated a group of homes from the electricity grid with the use of solar panels and batteries.

Figure 9-7: Mooroolbark Mini Grid

- **Networks Renewed Trial** – We joined the University of Technology Sydney in an ARENA funded project called Networks Renewed. This project looked to test the ability of modern smart solar and battery inverters to provide reactive power support to the network to help manage supply voltage levels (see figure below). The project was implemented on a SWER system just outside Yackandandah, where solar uptake is high and where voltage variations were being experienced. Importantly, this innovative trial proved that voltage can be suppressed during high solar export periods by controlling the reactive power capabilities of residential smart inverters. This project was awarded the Clean Energy Council's Innovation Award in 2019.

[39] We discuss our award-winning approach to innovation in Chapter 11. Innovation is fundamental to ensuring that we can continue to deliver benefits to our customers over the longer-term.

Figure 9-8: Networks Renewed



- **Australia's first community mini grid launched in Yackandandah** – As a result of a partnership between Mondo Power, AusNet Services and Totally Renewable Yackandandah (TRY), a mini grid was launched for the Yackandandah community in North East Victoria in 2017. This pioneering community energy project involves 169 homes and combines rooftop solar systems, battery storage and Mondo Ubi – the smart energy monitoring and management system powering the mini grid. The mini grid provides participating households with information about how much solar energy they are generating, how much the whole community is generating and how they are progressing towards their 100% renewable goal.

Figure 9-9: Yackandandah

- **C&I Demand Management Contracts** – We entered into demand management contracts on specific feeders with commercial and industrial (C&I) customers to manage summer peak demand. The portfolio of approximately 17.5 MW of demand management contracts targeted 22 kV feeders that were forecast to reach thermal overload within the next three years and, to provide broad contingency response, included zone substations with forecast energy at risk under a single contingency and strategic customers.
- **GoodGrid** – To continue building capability in residential customer demand response, we launched the GoodGrid program in late 2018 in suburbs where the network is forecast to experience risk. GoodGrid builds on the prior small scale pilot project Peak Partners, and

focuses on providing cash rebates to encourage customers to make voluntary manual load reductions at times of peak network demand. The technology solution utilises smart meter data analytics combined with an SMS communications platform. Approximately 1,000 customers have registered with GoodGrid.

- **Grid-scale Energy Storage System (GESS)** – We are currently deploying a GESS in the township of Mallacoota which, due to its location on the fringe of our network, currently experiences a relatively high number of supply interruptions. The GESS, which is financed through the DMIA, is expected to improve reliability for Mallacoota residents by up to 90% from 2019.

Figure 9-10: GESS

AusNet Services GESS facility. Image courtesy ABB.

In the 2022-26 regulatory period, we will continue to consolidate and build network support capability by:

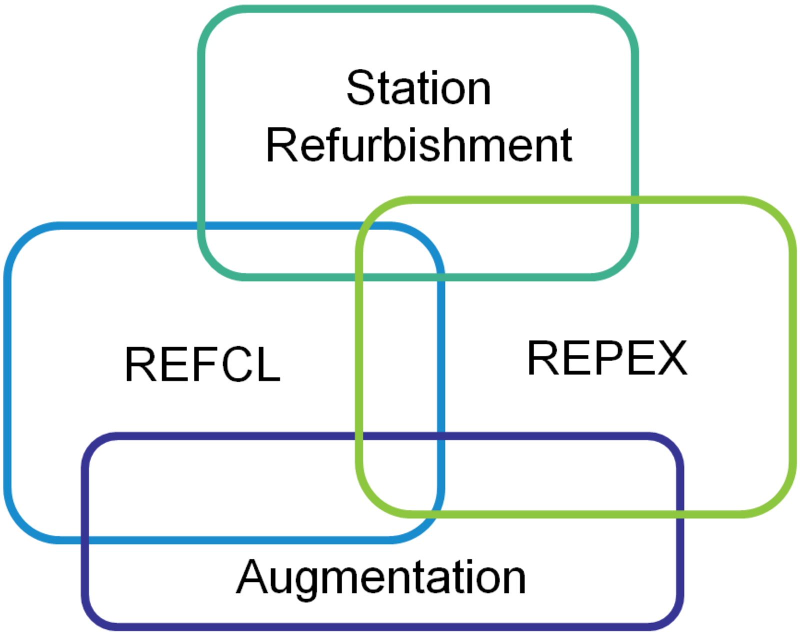
- strengthening our capability in the application of network support services;
- increasing the level of contracted network support where it is economic to do so, including via active consideration of the scope for non-network opex in RIT-D assessments; and
- integrating new innovations into our business as usual processes.

In this proposal, we have ensured that opportunities to meet customers' needs through network support has been factored into our expenditure proposals. For example, our opex plans include the deferral of a fourth transformer at the Cranbourne Terminal Station (see Chapter 10).

9.6.3 Top-down review

We recognise that there is scope for overlap and synergies between programs within our capex proposal for the 2022-26 regulatory period, especially where we expect work to occur at the same location or propose to replace the same asset. For example, the replacement of one asset may require the replacement of other physically or electrically connected assets – see the figure below.

Figure 9-11: Station related capex programs and projects



Where a potential overlap between projects is present, we consider the extent of the overlap, list the specific overlaps and then remove those overlaps. We then apply a top-down adjustment to all the programs and projects in our capex forecast to ensure we capture any interrelationships. Where there is no overlap between projects, we make this clear when developing our program.

Following our consideration of all the proposed programs contained in this proposal, we calculated the total value of the overlaps that we needed to remove. For our 2022-26 regulatory proposal, that was $151.8 million ($2021), demonstrating our commitment to efficiency when developing our forecasts (and keeping prices low for customers). As is common when applying such an adjustment, we have applied this amount across a portfolio of projects, rather than specific projects.

In addition, recognising the scope for deliverability efficiencies across the overall capex portfolio, we have applied an additional 0.8% top-down adjustment. The inclusion of this efficiency saving adds further credibility to our capex forecasting methodology and our overall forecast, as well as ensuring we meet the AER's expectation of a top-down review that we infer from our review of its recent decisions for other networks.

9.6.4 Benchmarking

The AER is required to have regard to its most recent annual benchmarking report as part of its assessment of our capex forecasts. We support the use of benchmarking to inform a high-level comparative view of efficiency where relevant. There are numerous benchmarking approaches, each of which has the scope to provide insight into a company's performance. However, when considering benchmarking for electricity networks, network-specific factors that affect headline results need to be considered.

Factors that affect our overall capex productivity include:

- the relatively large proportion of residential load in our customer base that results in comparatively low energy throughput and increases the peaky nature of demand, thus lowering measured productivity; and
- the high proportion of our network that is in high bushfire risk areas. This means we incur significant costs related to maintaining and improving community safety and meeting bushfire requirements (which are not measured as an output in the AER analysis), which also reduces measured productivity.

In its most recent (2018) annual benchmarking report, the AER explained that Multilateral Total Factor Productivity (MTFP) is the headline technique it uses to measure and compare the relative productivity of DNSPs. The MTFP technique allows the AER to compare total productivity levels between DNSPs and informs its assessment of the relative efficiency of each service provider.

The AER's analysis shows that from 2016 to 2017, we achieved the highest MTFP improvement of all DNSPs in the National Electricity Market (NEM), with a 13% increase in productivity, placing us in the middle of the group in terms of total factor productivity.[40]

Notwithstanding this positive improvement, we have concerns with the treatment of overheads in the AER's benchmarking. DNSPs' use different accounting treatments in their regulatory reporting, which can lead to materially different benchmarking outcomes. To address this, presenting productivity performance normalised for overhead capitalisation policies may be appropriate. This is an approach applied in many overseas jurisdictions. This is an issue the AER may wish to consider as it refines its benchmarking approach.

The AER's annual benchmarking report examines other partial productivity measures, including total cost per customer. The AER states:[41]

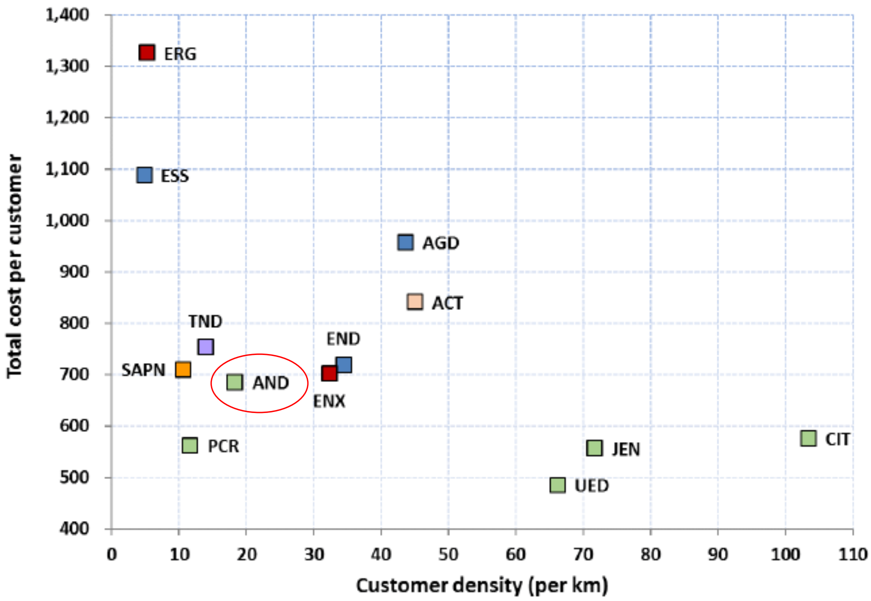
> *Customer numbers are arguably the most significant output DNSPs provide because the number of customers connected to the network drives demand and the infrastructure required to meet that demand.*
>
> *Broadly, this metric should favour DNSPs with higher customer density because they are able to spread their costs over a larger customer base. However, it is worth noting that there is a large spread of results across the lower customer density networks. In particular, Ergon Energy and Essential Energy have relatively higher cost per customer relative to SA Power Networks, Powercor and AusNet Services, who share similar levels of customer density.*

The figure below shows our total cost per customer (denoted as "AND") alongside our peers. As highlighted by the AER, we have similar levels of customer density to Ergon Energy (ERG) and Essential Energy (ESS), but relatively lower costs per customer, and have broadly similar costs to SA Power Networks (SAPN).

[40] AER, Annual Benchmarking Report - Electricity distribution network service providers, November 2018, p. 11.

[41] Ibid, p. 34.

Figure 9-12: Total cost per customer ($2017) v. customer density (average 2013-17)

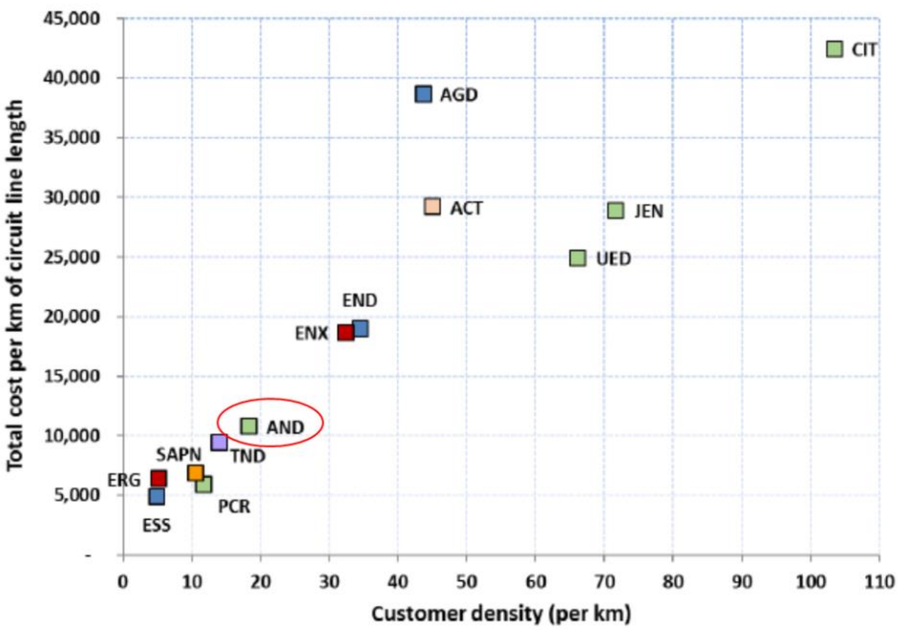


Source: AER, Annual Benchmarking Report - Electricity distribution network service providers, November 2018, Figure 5.3.

The AER's analysis shows that in terms of total cost per customer, we are among the best performers of the networks that have relatively low customer densities.

Similarly, we perform well in terms of total cost per kilometre of line length, as shown in the figure below.

Figure 9-13: Total cost per km of circuit line length ($2017) v. customer density (average 2013–2017)



Source: AER, Annual Benchmarking Report - Electricity distribution network service providers, November 2018, Figure 5.4.

Although benchmarking analysis suffers from measurement difficulties, particularly in relation to bushfire risk and differences in DNSPs' accounting treatments of overheads, there is strong evidence that we are an efficient performer relative to our peers. The results published by the AER in its 2018 annual benchmarking report indicate that we have achieved significant productivity improvements since 2016 and that we are a good performer relative to our peers, in terms of total and partial productivity performance measures.

The AER's analysis should therefore give stakeholders some confidence that our cost performance compares well with our peers and that our forecasts reflect efficient unit rates, planning and delivery processes.

9.7 Capex negotiations with the Customer Forum

We, together with the Customer Forum and the AER, agreed on which parts of our capex proposal would be subject to negotiation between us and the Customer Forum. The agreed scope of our negotiations therefore reflects the areas where it was considered that the Customer Forum could add the most value, including by presenting our customers' perspective with respect to:

- demand for a service;
- the level of service to provide;
- how much to spend to provide the service; and
- the timing of that proposed spend.

More information about the Customer Forum and its role in developing this proposal is at Chapter 4.

With respect to capex, the Customer Forum has been involved in negotiating and, therefore, shaping aspects of our major projects augex proposal and major projects repex. At the conclusion of our negotiations with the Customer Forum, it had negotiated around 7% of our total net capex proposal (covering augex, repex, DER and innovation).

Our engagement with the Customer Forum (and other stakeholders) occurred over several months and has allowed the "voice of the customer" to be better reflected in our capex proposal. In particular, the Customer Forum has:

- been provided with additional information to allow it to better understand and assess around 7% of our total net capex proposal;
- challenged the network and non-network options considered for the limited number of capex projects it was negotiating with us;
- interrogated whether our proposed solutions to the (limited number of) capex issues it was considering, delivers the right balance between affordability and reliability; and
- resulted in us improving our capex proposal to better reflect customers' needs and preferences.

The Customer Forum also negotiated with us on our proposed innovation expenditure, which is also relevant to our capex forecasts. The Forum considered there were longer-term benefits in us undertaking a modest amount of investment as part of the 2022-26 regulatory period (see Chapter 11).

Box 1: Impact of the Customer Forum on our capex proposals

In addition to increasing transparency in and scrutiny of specific aspects of our capex proposals, the Customer Forum has ensured that our capex proposal (as a whole and for the approximate 7% of our total net capex proposal considered by it) now better reflects customers' preferences. Some of the ways we have achieved this include significant reductions in our proposed portfolio of repex major projects. This has been achieved through:

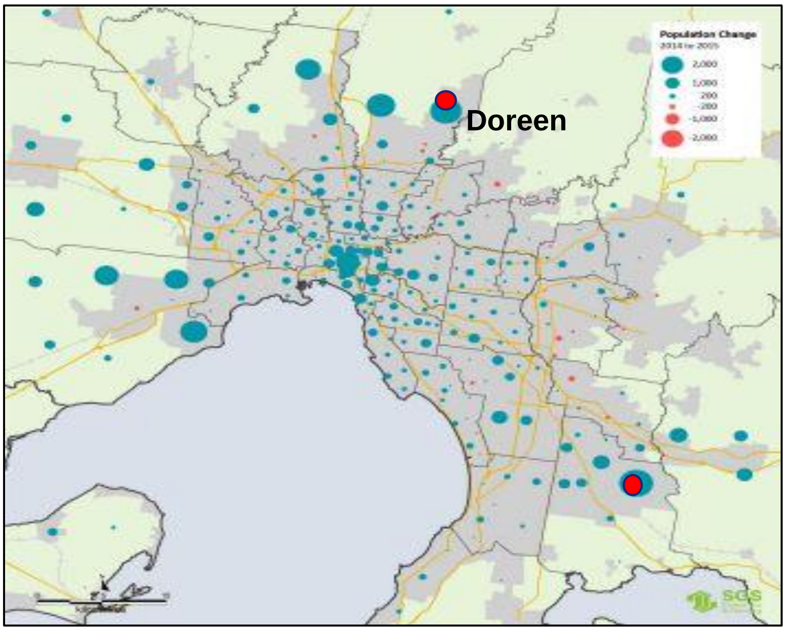
- deferring the Watsonia, Traralgon, Thomastown and Bayswater substation projects by one year;
- deferring of the Newmerella substation project to the next regulatory period;
- bringing forward of the Bairnsdale project into the current regulatory period to align with REFCL work; and
- reducing the scope of several projects to prioritise cost savings over (marginal) reliability.

Further information on our repex and augex is presented below.

9.7.1 Major augmentation projects

Our discussions with the Customer Forum commenced prior to the Government's decision to modify the years over which we are regulated (from a calendar to a financial year basis). The Customer Forum therefore initially considered two proposed major network growth projects for the (then) 2021-25 regulatory period: the augmentation of the Clyde North and Doreen zone substations. These two augmentation proposals sought to increase the network capacity to supply the strongly growing customer base and associated demand in these areas.[42]

Figure 9-14: Melbourne's population growth



Source: SGS Economics and Planning 2016.

[42] As part of its consideration, the Customer Forum initiated some telephone survey work in late 2018 to determine the views of customers in Clyde North and Doreen. One hundred and fifty customers were randomly sampled in each location. The key findings from this survey work showed that the majority of surveyed customer supported investment to maintain reliability and a willingness to participate in shorter term demand management schemes.

The initial expenditure forecasts (in $2020 including overheads) for these projects were:

- Clyde North zone substation: $7.7 million, comprised of $0.4 million in 2020 and $7.4 million in the 2021-25 regulatory period; and
- Doreen zone substation: $5.1 million, with $4.7 million in the 2021-25 regulatory period and $0.4 million in 2026 (a project that we withdrew from our negotiations with the Customer Forum following a re-assessment of the expected demand at this zone substation).

We provided the Customer Forum with options for the timing and scope of these projects, including:

- a preferred network option that would expand the capacity of the Clyde North and Doreen zone substations; and
- delaying the projects, using generating plant connected to the distribution network, battery storage and agreements with customers to reduce demand at peak times.

Prior to considering these projects, the Customer Forum requested further analysis of alternative options that were capable of economically deferring these projects, particularly given the relatively high penetration and growing number of solar customers in Clyde North.

We therefore engaged a consultant (WSP) to undertake an independent review of the augmentation deferral options for projects at Clyde North and Doreen zone substations. The scope of the review was to assess the reasonableness of the method, data sources and assumptions used to determine the costs and benefits of the deferral options in the context of our proposed network solution.[43] However, as we withdrew the Doreen zone substation from our negotiations with the Customer Forum, this independent review focused on the Clyde North zone substation.

Having considered WSP's report and other information provided through the course of our negotiations with it, the Customer Forum was satisfied with our capex proposal for the Clyde North zone substation.

We also discussed with the Customer Forum subsequent changes to our Clyde North zone substation proposal arising from the movement to a new regulatory period and our decision to apply updated inflation assumptions. The Customer Forum agreed with our proposed changes and as a result we retained the Clyde North zone substation project in our augex proposal. Section 9.11 contains updated information on our Clyde North zone substation proposal, including our proposed expenditure.

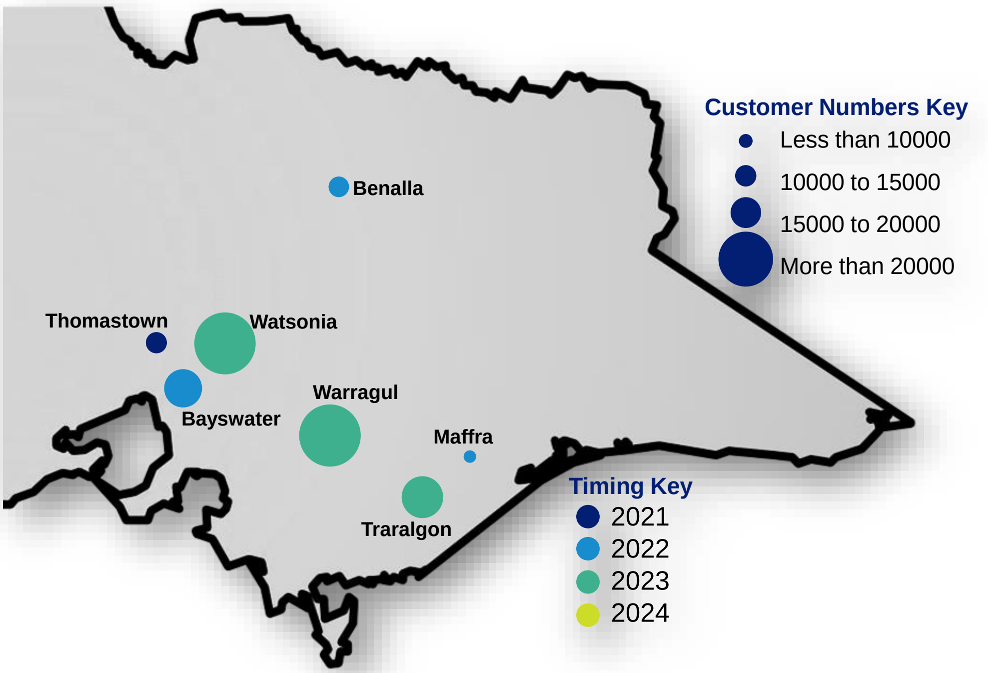
9.7.2 Major repex projects

As per the discussion on major augmentation, the Customer Forum initially reviewed our proposal to rebuild nine zone substations for the 2021-25 regulatory period. We considered that obtaining the Customer Forum's views on these zone substation projects was particularly important as:

- these stations collectively supply about 20% of our customers and are located across our network (see the figure below);
- the Customer Forum could add significant value by considering the choices to be made about whether to offer a service, the level of service to provide, how much to spend and the timing of that spend; and
- the Customer Forum could help us balance ongoing affordability concerns with continued provision of a reliable network in an increasingly complex environment.

43 WSP, Augex deferral review for Clyde North and Doreen zone substations, April 2019.

Figure 9-15: Major replacement projects and timing as proposed by AusNet Services



Our proposed major repex projects looked to maintain reliability by replacing equipment that had deteriorated within several zone substations at a cost of $102 million ($2020) across the 2021-25 regulatory period. Unaddressed, this deteriorating equipment would increase:

- the risk of asset failure;
- safety risk; and
- the scope for unplanned interruptions to customer supply.

The Customer Forum considered the timing of each of these projects, including our preferred timing, as well as six alternative options with different costs and reliability outcomes. The Customer Forum's role was to consider the material provided, ask for further clarifications/information where required and identify its preferred option for each project, being the one that balances the cost and reliability choices in a way that best reflects our customers' preferences.

Given the current focus on affordability, the Customer Forum considered it would be consistent with customer preferences for us to explore the scope to defer some of these repex projects where the expected increase in reliability risk was relatively small. We therefore undertook that analysis and, having considered the material we presented, negotiated and agreed the following project deferrals:

- Watsonia, Traralgon, Thomastown and Bayswater projects being deferred by one year; and
- Newmerella being deferred to the next regulatory period.

As part of these negotiations, the Customer Forum acknowledged that these deferrals would reduce reliability performance which would, in-turn, necessitate the following adjustments to the AER's Service Target Performance Incentive Scheme:

- an increase in our SAIDI target by 2.45 minutes (SAIDI); and
- an increase in our SAIFI target by 0.06.

The Customer Forum also indicated that these changes should be tested with customers and stakeholders.

Consequently, in February and March 2019, the Customer Forum initiated a survey (among customers supplied by the zone substations in the proposed project locations) to establish customer preferences on reliability and the timing of the major repex projects. A stratified random sample of 500 customers was surveyed, including residential (76%), business (17%) and farming (7%) customers.

This survey found:

- 95% of survey participants considered it either quite important or very important that current reliability be maintained;
- Without having regard to cost, 87% considered we should be addressing the risk of reduced reliability in their location in the next five years to seven years;
- For residential customers:
  - 75% would prefer to pay an additional $0.17-$0.80 per annum during the next regulatory period to improve reliability in their location, rather than face a 50% increased risk of power outages if the works were deferred and then pay a greater amount in 2026 and beyond; and
  - 70% would prefer to pay an additional $0.80-$3.38 per annum during the next regulatory period to improve reliability across all locations, rather than face a 50% increased risk of power outages if the works were deferred and then pay a greater amount in 2026 and beyond
- For business/farm customers:
  - 79% would prefer to pay an additional $1.54-$6.95 per annum during the next regulatory period to improve reliability in their location, rather than face a 50% increased risk of power outages if the works were deferred and then pay a greater amount in 2026 and beyond; and
  - 68% would prefer to pay an additional $7.42-$33.59 per annum during the next regulatory period to improve reliability across all location, rather than face a 50% increased risk of power outages if the works were deferred and then pay a greater amount in 2026 and beyond.

These findings revealed that customers in areas where reliability may be affected by aging infrastructure have a strong preference to maintain current reliability levels and are not willing to accept lower reliability associated with project deferral, despite the bill reductions this would provide.[44]

As our discussions with the Customer Forum progressed, we also refreshed the economic modelling underpinning each major repex project to capture the latest available information, including:

- finalised project scopes;
- finalised costings and forecasts; and
- interactions with the REFCL program.

[44] We, together with the Customer Forum, accept that these results are affected by survey participants' ability to fully understand the stated price increases in the context of changes in their overall energy costs. Furthermore, the survey does not consider the views of customers outside the locations, who would be affected by the cost, but not the reliability, impacts of the projects. Given statistical accuracy is a function of sample size, all other factors being equal, the results for subgroups, such as farm customers are less accurate than the results for the total sample. Nonetheless, the research findings are indicative of customer price and reliability preference and, in the absence of location-specific VCRs in each zone substation location, were a useful and relevant source of information for the Customer Forum.

This refresh resulted in:

- the Newmerella project being deferred to beyond the end of next regulatory period;
- the Bairnsdale project being brought forward to the current period to align with REFCL work; and
- large reductions in scope to several projects to reflect a preference for cost savings over marginal reliability benefits.

Due to these changes, the total cost of our preferred portfolio of major repex projects decreased from $102 million ($2020) to $78 million ($2020).

Through our engagement with the Customer Forum and by updating our modelling we were also able to respond to the feedback received from customers and ensure that each individual project was economically justified, and that expenditure/risk trade-offs were made where possible. Importantly, because of the overall reduction in our repex proposal, our proposal makes significant steps in addressing our customers' affordability concerns.

Following initial agreement with the Customer Forum we subsequently agreed to make further minor adjustments to the proposal. This was required due to us transitioning to a new (financial year) regulatory period and updating our inflation assumptions. Further information on our repex proposal, including our forecasts is in section 9.8 below.

9.7.3 DER expenditure

The Customer Forum reviewed our proposal for augmentation to enable additional DER export capabilities as well as the expenditure on the smart networks proposal. As part of our engagement, the Customer Forum identified some overlap in our expenditure forecasts, which we subsequently removed. We also undertook customer research to demonstrate that our customers value expenditure on enabling additional solar export and support sharing the costs of this enablement across the customer base.[45] The Customer Forum has supported our DER program on the basis that the AER will assess the cost forecasts.

9.8 Replacement capital expenditure

9.8.1 Overview

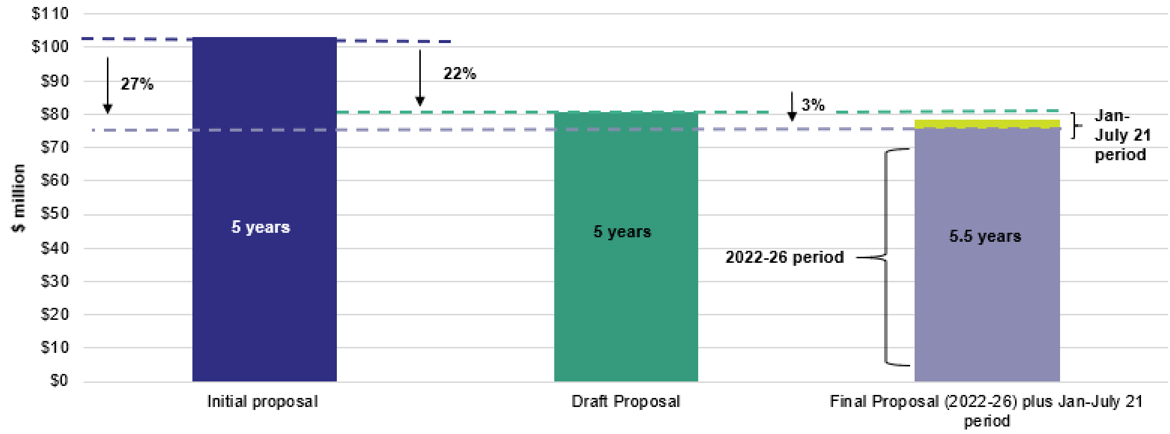
Our repex proposal involves a forecast of $543.3 million ($2021) over the 2022-26 regulatory period. This is 14% higher than the expected repex ($476.3 million ($2021) in the current regulatory period.

Our repex forecast includes expenditure of $78.3 million ($2021) for major repex projects over the 2021-26 period (the period 1 January 2021 to 30 June 2021 and the next regulatory period), which the Customer Forum has negotiated with us. This $78.3 million ($2021) comprises $2.6 million ($2021) for the period 1 January 2021 to 30 June 2021 and $75.7 million ($2021) for the 2022-26 regulatory period.

The forecast $75.7 million ($2021) for major repex projects in the 2022-26 regulatory period represents a significant reduction on our initial proposal and a 3% ($4.7 million ($2021)) reduction on our Draft Regulatory Proposal (see figure below).

[45] JWS Research, Community Perceptions Toward Solar and Innovation Propositions, prepared for AusNet Services, September 2019.

Figure 9-16: Major repex project ($2021m, direct costs



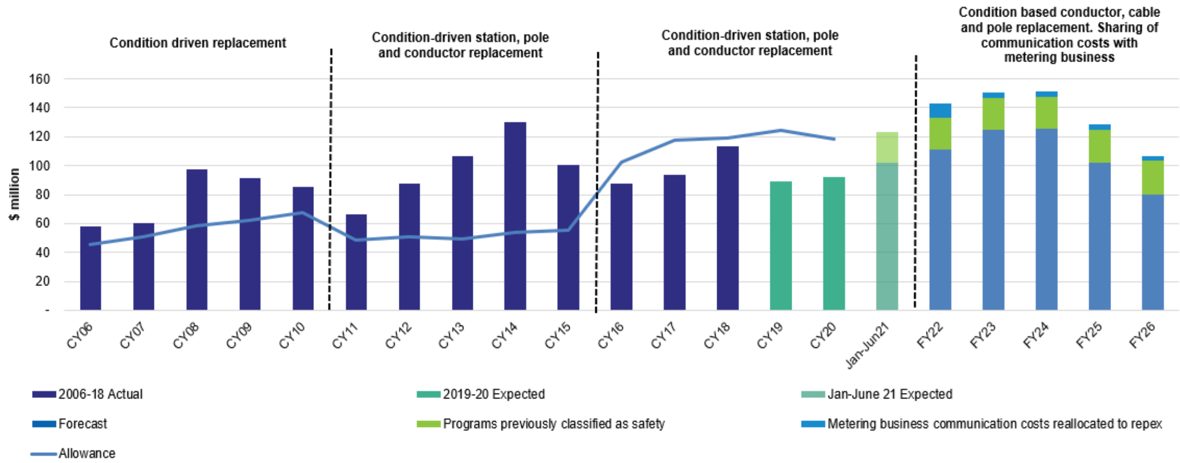
Our proposal will help address ongoing customer affordability concerns while ensuring the continued provision of a reliable network in an increasingly complex and challenging environment – outcomes we know that our customers value.

In comparing our forecasts with historical repex, we note the following changes in cost categorisation:

- Conductor and cross-arm expenditure is now captured in repex for the 2022-26 regulatory period, whereas a large part of this expenditure was previously classified as a safety program.
- Replacement communications assets that are required for the distribution business are considered repex for the 2022-26 regulatory period, whereas these costs were previously classified as metering and, therefore, excluded from repex.

The dollar and percentage increase in forecast repex described above takes account of these reclassifications to ensure a like-for-like comparison. Without taking these reclassifications into account our repex forecast of $680.76 million ($2021) would be 43% above the expected repex in the current period.

Figure 9-17: Total replacement capex 2006 to 2025, incl. overheads ($m, $2021)



Note:

Jan to June 2021 is presented on an annualised basis.

9.8.2 Key drivers

The key drivers for our repex in the next regulatory period include:

- deterioration in asset condition associated with increasing asset age, which gives rise to unacceptable reliability and safety risk;
- a reduced opportunity to replace poor condition assets as part of augmentation-related projects;
- asset failure risk, which may cause supply interruptions, increased risk of collateral asset damage, safety risk to public and field personnel, and environmental damage from asset failure;
- technical obsolescence, which increases the cost and risk of retaining assets in service; and
- asset damage caused by third parties.

Unlike previous regulatory reviews, where the asset replacement programs were developed based on a 'maintain current reliability case', we have, together with the Customer Forum, carefully considered the impact of deferrals on affordability and reliability. This approach has allowed us to negotiate changes to our portfolio of works where the impact on reliability is likely to be minimal.

9.8.3 Projects and programs of work

The table below show the principal replacement projects and programs for the 2022-26 regulatory period, including the proposed expenditure and the percentage each project/program contributes to this expenditure category.

Table 9-4: Repex projects and programs for the 2022-26 regulatory period, direct costs ($m, 2021) and %

Project/Program	Total $M	% of total
Zone substation rebuilds (negotiated with the Customer Forum)	75.7	12%
Stations	20.0	3%
Poles	202.1	33%
Conductors	69.8	11%
Cross-arms	68.0	11%
Services	4.0	1%
Protection and control	27.5	4%
SCADA and comms	27.7	5%
Metering related Network Comms	22.2	4%
Other	96.4	16%
Total	**613.4**	**100%**

9.8.3.1 Zone substation replacement

As discussed in section 9.7, the Customer Forum agreed to expenditure for seven major zone substation replacements. Below is an outline of each major substation rebuild we are proposing.

Table 9-5: Description of the major repex projects for the 2022-26 regulatory period

Project / Zone substation	Project description
Thomastown	This substation commenced operation as a 66/22 kV transformation station in the early 1950s. Two 20/27 MVA transformers were installed in the early 1960s and a third 20/30 MVA transformer was installed in the late 1960s. Two 66 kV and eighteen 22 kV bulk oil circuit breakers were installed at this station in the 1950s and 1960s. The physical condition of some assets has deteriorated and they are now presenting an increased risk of failure. This project involves replacing the 66 kV and 22 kV circuit breakers.
Benalla	This substation was established in the 1940s and consists of three 10/13.5 MVA 66/22 kV transformers supplied from two 66 kV lines emanating from Glenrowan Terminal Station. It has a third 66 kV line that radially supplies Mansfield zone substation. The station has a mixture of bulk oil and vacuum circuit breakers, and the physical and electrical condition of some assets has deteriorated and they are now presenting an increased failure risk. This project involves replacing the 66 kV and 22 kV circuit breakers.
Bayswater	This substation commenced operation as a 66/22 kV transformation station in the late 1960s with three power transformers and two 66 kV lines, one from Ringwood Terminal Station and the other from Boronia zone substation. A third 66 kV line was constructed in 2015 and is a three legged line from Ringwood Terminal Station to Bayswater and Croydon. There are seventeen 22 kV bulk-oil circuit breakers at the station, which were installed in the 1960s and 1970s. The physical and electrical condition of some assets has deteriorated and they are now presenting an increasing failure risk. The project involves replacing the 22 kV switchgear.
Maffra	This substation commenced operation as a 66/22 kV transformation station in 1960. The two 10/13.5 MVA transformers were installed in 1960 and a third 10/13.5 MVA transformer was added in 1998. The 66 kV switchyard was constructed in the 1960s. The 22 kV switchyard was replaced by an indoor switchboard in 1998. The physical and electrical condition of these assets has deteriorated and they are now presenting an increasing failure risk. The station has a 66 kV ring bus, however, all three transformers are switched as a single group, hence faults on the 66 kV transformer bus or any one of the transformers will result in a loss of supply to all customers. The project involves replacing the 66 kV circuit breakers and moving to a modern switching arrangement.
Watsonia	This substation commenced operation in the late 1950s with two 66/22 kV power transformers. A third transformer was installed in 2010 and the station now includes two 66 kV bus-tie circuit breakers and is supplied by

Project / Zone substation	Project description
	two incoming 66 kV lines. The outdoor 22 kV switchyard consists of eleven 22 kV feeders and a 10 MVAr capacitor bank. To manage short circuit current levels within asset capabilities and rules requirements, only two of the power transformers operate in parallel, with the third operating as a hot spare under normal conditions via normally open 22 kV transformer circuit breakers connected to each of the 22 kV buses. This arrangement allows quick restoration to near system normal capacity following outage of either of the two normally loaded transformers. There are fifteen 22 kV bulk-oil circuit breakers at the station which were installed in the 1950s and 1960s. The physical and electrical condition of these assets has deteriorated and they are now presenting an increasing risk of failure. The project involves replacing the 22 kV circuit breakers.
Traralgon (Stage 2)	This substation commenced operation as a 66/22 kV transformation station in 1969. There are two 10/13.5 MVA transformers, were manufactured in 1949 and 1979, and one 20/33 MVA transformer, manufactured in 2012. The 22 kV switchyard consists of one indoor switchboard with four feeders installed in 2013, and three outdoor 22 kV busses with four feeder circuit breakers installed in 1969. The 66 kV switchyard has had some modifications since the site was established, and now consists of two 66 kV lines to MWTS and one line to Maffra one substation. Two of the 66 kV circuit breakers were installed in 1977, while the other two were installed in 2013 when the new 20/33 MVA transformer was installed. The physical and electrical condition of some assets has deteriorated and they now present an increased failure risk. The station 66 kV bus is partially switched with the two 10/13.5 MVA transformers connected in a single switching zone group. The project involves replacing two transformers, 66 kV circuit breakers and 22 kV switchgear.
Warragul	This substation commenced operation as a 66/22 kV transformation station in 1962. Three 10/12.5 MVA transformers were installed in 1962. A fourth 10/13.5 MVA transformer was added in 1997 as a replacement for an existing 5/6.5 MVA transformer, however this transformer was manufactured in 1965. A fifth 20/33 MVA transformer was added in 2011. The 66 kV switchyard was constructed in the 1960s, with the exception of an additional 66 kV CB added in 2011 when the fifth transformer was installed. The 22 kV switchyard was replaced by an indoor switchboard in 1997. The physical and electrical condition of some assets has deteriorated and they are now presenting an increasing failure risk. The station has a 66 kV ring bus arrangement, but is partially switched with the four 1960s vintage transformers switched as a single group, and a normally open isolator in place of a 66 kV circuit breaker between the two 66 kV line entries from the Yallourn Power Station. The project involves replacing the four 10/12.5 MVA transformers with two 20/33 MVA transformers, replacing the existing capacitor bank and installing two new 66 kV circuit breakers. (The existing C5 66 kV circuit breaker is being replaced under a separate project before 2021.)

Where different station asset programs overlap at a location, a zone substation major refurbishment project enables us to target the replacement of deteriorated plant and equipment within zone substations most efficiently. These projects typically include the replacement of major plant such as transformers, circuit breakers and ancillary equipment, such as protection systems or panels containing asbestos. All of the projects listed above adopt the optimal combination of asset replacement to balance the benefits (a reduction in the probability of asset failure and associated consequences) with the costs of the replaced assets.

9.8.3.2 Stations

Outside of the major station rebuilds, we propose to undertake asset repex at stations including:

- The replacement of 135 circuit breakers over an eight year period ending in 2026, 32 of which will be replaced as part of a dedicated repex program within the next regulatory period. This proposed replacement is supported by cost-benefit analysis, including assessments of the risk and consequence of asset failure. Our analysis shows that these circuit breakers will reach end of their life during the regulatory period and are minimum oil or bulk oil types in very poor condition. At end of life, these circuit breakers pose significant safety risk.
- The replacement of power transformers in accordance with our asset management strategy. This strategy considers, among other issues, transformer type, asset condition and historical failure modes to optimise the replacement decision. For the 2022-26 regulatory period, our forecasts deliver a modest reduction in repex for power transformers compared to our recent historical spend.

While it is not anticipated that any switchboards will require retirement within the next regulatory period, first generation indoor switchboards are more than 40 years old and have the highest safety risk of arc flash. Remedial work such as purchasing a spare switchboard, circuit breaker retrofits and installation of arc flash mitigation will be required to reduce the risks and consequences of failure.

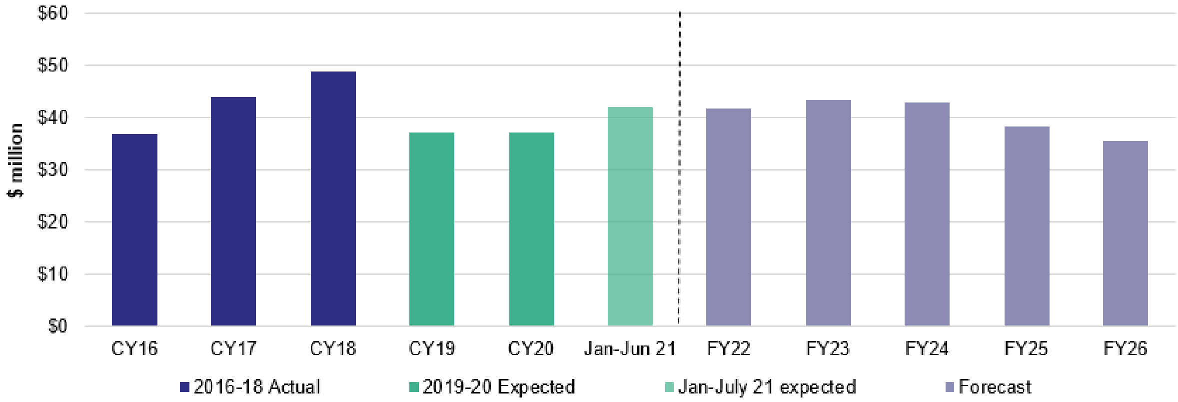
9.8.3.3 Poles

The pole replacement program is the largest of the repex programs we are proposing. It involves the replacement of poles that, after inspection, pose an unacceptable risk in terms of public safety, bushfire ignition and/or supply reliability. For example, in October 2019 the ESV concluded that a fire at Garvoc resulted from a broken power pole.[46] Depending on a pole's condition, our replacement program can also involve remediation through staking.

Our proposed expenditure for poles for the 2022-26 regulatory period is relatively stable at $202.1 million ($2021). This is a 1% reduction on the expected expenditure during the current regulatory period.

46 Victorian Government, ESV prosecutes Powercor over St Patrick's Day fires, available at: https://esv.vic.gov.au/wp-content/uploads/2019/10/20191024_MR_Powercor_charges.pdf (accessed 26 November 2019).

Figure 9-18: Actual, expected and forecast pole replacement capex, 2016-26, direct costs ($m, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

In line with industry trends, we are increasing our current staking rates, a lower cost alternative to replacement.[47] We are also exploring alternative pole staking and rebutting techniques, including using new timber preservatives and pole reinforcement techniques that, if demonstrated suitable, will provide another lower cost alternative to replacement.

In response to the Saint Patrick Day fires, the ESV is conducting a review of DNSP asset management with a focus on poles.[48] The outcome of this review will be known in 2020 and may result in further increases to pole replacement rates. We also note that the fires currently being experienced across Victoria may, together with the outcomes of any inquiries or commissions, require us to reconsider our current approach to pole replacement, and could result in greater use of concrete poles.

9.8.3.4 Conductors

Our conductor replacement program is the second largest of the repex programs we are proposing for the 2022-26 regulatory period. The volume of condition-based conductor replacement is increasing from around 200 km in the current period to 270 km per annum in the 2022-26 regulatory period. This increase is due to:

- the deteriorated condition of assets, particularly in the alpine areas of the network; and
- an improved risk assessment methodology, which now captures high-risk assets in low consequence areas in addition to high consequence areas.

Despite an increase in our volumes forecast, our proposed conductor repex for the next regulatory period is $69.8 million ($2021), which is 4% lower than the conductor repex expected in the current regulatory period due to lower unit rates.

In addition to the condition-based conductor replacement, we are proposing a new, safety-driven program to insulate or underground SWER conductor lines in Codified Areas. This program will continue the work begun in the current period under the Poweline Replacement Fund. While the figure below captures all these programs, we discuss safety related capex in Section 9.9.

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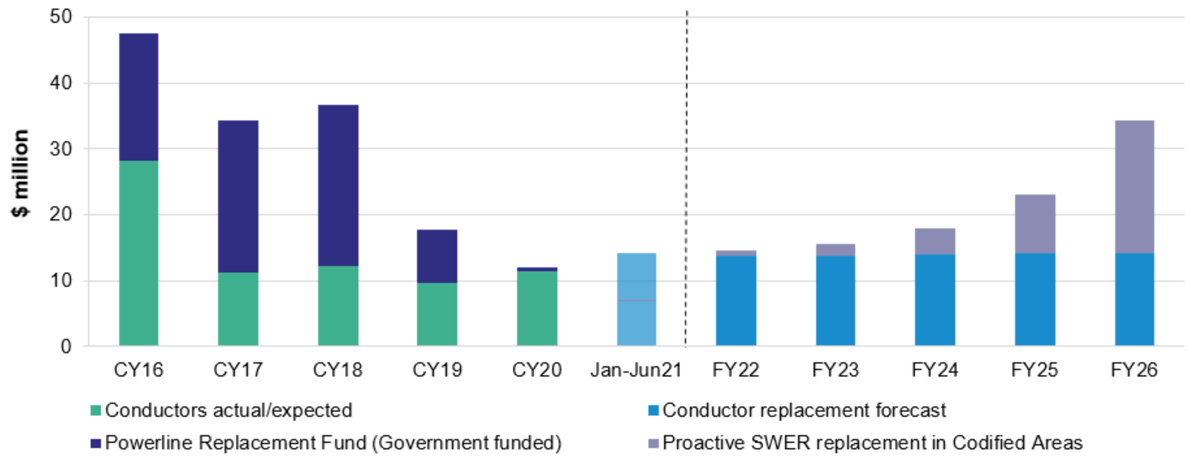
[47] The unit rate for staking a pole is around $1000 while the unit rate for replacing a pole is around $15,000, representing a significant saving for customers. The staking also extends the life of a pole by another 10-15 years.

[48] See: https://esv.vic.gov.au/news/st-patricks-day-fires-technical-reports/ (accessed 15 January 2020).

Figure 9-19: Actual, expected and forecast conductor replacement capex together with actual and expected safety conductor capex 2016-26, direct costs ($m, $2021)



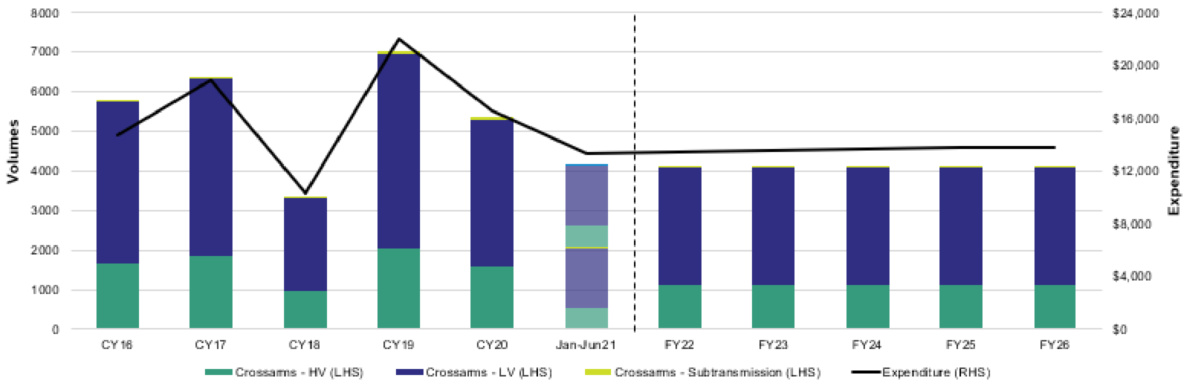
Note: Jan to June 2021 is presented on an annualised basis.

9.8.3.5 Cross-arms

This is an ongoing program to replace defective cross-arms to maintain network safety and reliability. The proposed replacement volumes are approximately 4,000 per annum, a reduction from the average replacement rate of approximately 4,300 per annum expected for the current period.

As shown in the chart below, cross-arm replacement volumes are forecast to be around 26% below those expected in the current period.

Figure 9-20: Cross-arm replacement volumes and expenditure, 2016-26, direct costs ($'000, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

With respect to expected expenditure, we are forecasting costs of $68 million ($2021) for the next regulatory period, which is around 17% less than that expected in the current regulatory period.

9.8.3.6 Services

Our services replacement program targets aerial service cables that are in poor condition and which pose an unacceptable safety risk if not replaced in the proposed timeframes.

We proactively analyse AMI meter data and dispatch fault crews to emerging service cable failures to mitigate risk of electric shocks in customer's premises. This data reveals fleet problems, therefore, the continued proactive replacement of service cables in poor condition is necessary to ensure we can continue to mitigate the risk of electric shock to our customers and maintain reliable supply. Economic analysis has demonstrated that a planned replacement program targeting service cables that are most susceptible to failure due to deterioration is more economically efficient than a purely reactive approach.[49]

9.8.3.7 Protection and control

The aim of this program is to manage risk associated with ageing protection and control assets through targeted, proactive replacement of high risk, poor condition assets.

To maximise project efficiencies, we typically aim to complete secondary asset replacements at the same time as primary asset renewal, refurbishment or augmentation works. Consequently, most secondary asset replacements occur as part of complex station projects. Only the highest risk, poorest condition or non-compliant assets located at sites where no complex station works is anticipated within the next 10 years are considered for replacement under this dedicated protection and control renewal program.

Our proposed program involves targeted, proactive replacement of 63 poor condition, high risk protection and control schemes (a total of 179 assets). A further 667 assets will be replaced as part of station and primary asset refurbishment programs, including REFCL installation works. Those assets are excluded from this program to avoid double counting.

9.8.3.8 SCADA and communications

Having 99 locations (15 radio sites, 69 zone substations and 15 terminal stations) with distribution communications assets, the aim of our proposal is to ensure that our communication assets remain in a healthy operating condition, with adequate levels of ongoing maintenance and vendor support. Our proposal also reflects our expectation that the number of distribution sites we have will increase over the next five years.

This proposal covers numerous types of communication, including:

- Protection signalling – between zone substations and terminal stations and between zone substations;
- Monitoring and Control (SCADA) – between the Network Operations Centre (CEOT) and zone substations and pole mounted medium voltage switches; and
- Operational Voice Communications – between CEOT, offices, depots, terminal stations and zone substations.

Our proposal has several elements, most notably, the replacement with modern equivalents of product lines where support and spare parts for some systems become increasingly difficult to secure.

9.8.3.9 Metering-related network communications

This program will ensure that we maintain service levels to customers with respect to meter readings and the performance of remote services for customers. The key aspect of this program involves replacing faulty communication cards within our smart metering network.

We also need to replace the communication network used to communicate with our meters. Telstra has indicated its intention to replace the 3G communications network we currently use with a network

[49] Our approach involves us placing all services in a risk matrix and then applying criteria to identify which of those we should pro-actively replace. The criteria we use to do this are: (1) Neutral Screen service cables - which has the highest failure rate; (2) proximity to one another (which results to a lower unit rate); (3) Condition score of C5 (very poor condition); and (4) Located in Non-Codified areas. The use of C5 condition and NS construction as criteria means selection of the cables with the highest probability of failure and the ones most likely to be economical to replace.

that only supports 4G and 5G+ services after 2022. We are therefore proposing to upgrade our network to support 4G communication by 2022, maintaining our ability to communicate with our meters and provide remote services for customers.

9.8.4 Benchmarking and validation

The AER uses a repex model as a statistical tool to conduct a top-down assessment of forecast repex. The model is used to benchmark repex that involves high volume asset classes – poles, overhead conductors, underground cables, service lines, transformers and switchgear – as follows:

- The repex model adopts asset age as a proxy for asset condition.
- The model predicts future replacement volumes based upon the current age profile of an asset population and expected replacement life.
- It assumes a normal distribution for the expected replacement life of an asset.
- The model assumes like-for-like asset replacement.
- The model assumes recent historical replacement rates are representative of expected future replacement needs, so it is calibrated such that the first year of the model output aligns with recent historical replacement rates. This is done by adjusting the expected mean asset replacement life.

We have used the AER's repex model to cross-check our expenditure forecast for these asset classes – see the table below.

Table 9-6: AusNet Services' forecasts v AER's repex model forecasts ($, real 2018)

Replacement program/asset class	Our current forecast ($m, real 2018)	Repex model forecast ($m, real, 2018)	Difference (%)
Poles	204,776	127,576	61%
Conductors	107,669	178,358	-40%
Cables	20,100	86,498	-77%
Service Lines	3,995	13,230	-70%
Transformers	15,572	41,430	-62%
Switchgear	70,671	36,067	96%
Total	**422,783**	**483,158**	**-12%**

Note: This table only compares the repex programs included in the AER's repex model.

Based on this modelling, our proposed repex for the 2022-26 regulatory period is 12% lower than the outputs of the AER's repex model. At a total level, our forecasts therefore benchmark favourably with the outputs of the AER's repex model. However, the table also shows that at the asset class level there are significant differences between our estimates and those produced by the AER's model. The reasons for the different outcomes for some asset classes are discussed below.

Poles

The AER's model predictions for poles are not directly comparable with our forecast as the AER's model assumes a like-for-like replacement (i.e. a wood pole will be replaced with another wood pole). This is quite different to our approach, where we use a 'blended' unit rate to model poles, as this is much more reflective of what we do in practice.[50] For example, when a wood pole needs attention we may stake it to extend its life or replace it. If it is replaced, we can replace it with another wood pole or with a concrete one (with the selection being determined by where the pole is located and the function of the pole).

Similarly, in the AER's model, the asset category 'Staking of a wooden pole' is interpreted as wood poles that have been staked and which will be replaced at end of the staked pole's life. Our modelling (again) uses a 'blended' unit rate as this is more reflective of what we do in practice.[51]

Other reasons for the differences between the outcomes of the AER's repex model and our forecasts include the model's:

- use of asset age as a proxy for condition, which does not reflect actual find rates and fleet problems;
- assumptions that the wood pole population is homogenous; and
- use of a unit rate based on data submitted in the Regulatory Information Notices (RINs), which is lower than the unit rate we use in developing our forecast (as the unit rate used in developing our forecast includes the cost of any service lines we replace when replacing a pole.[52]

Our forecasting approach is more reflective of other factors that affect pole conditions such as wood species, asset condition, failure history and risk. We also note that when reporting repex in the annual RIN, pole refurbishments are reported under 'Poles – Other' which does not have a corresponding age profile, so this expenditure is not included in the AER's model. In addition, and as mentioned above, our forecast for poles captures the cost of replacing some service lines (see below) where it is prudent and efficient to do so.

Given the above, the AER's repex model cannot be solely relied upon to provide an optimal expenditure plan. However, we accept that it can be a useful starting point for assessing future repex requirements, particularly where a simple age-based approach to replacement is required.

Cables

The AER's repex model assumes a per kilometre cable replacement. However, in practice, much of the repex on underground cables involves replacing cable joints and cable terminations, not the cable itself. We have therefore used a 'blended' unit rate per kilometre of cable – estimated using recent testing history on the number of joints, terminations and length of cables found to be in poor condition during the testing program – to forecast the necessary expenditure for cables.

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[50] To calculate our blended rate for wood pole replacement we use reported historical replacement volumes and expenditure for poles staking and wood and concrete pole replacements.

[51] To calculate this we have used historical replacement volumes and expenditure for LV and 22 kV wood poles to model staked poles replaced by a pole.

[52] Where a pole is replaced, if a service line is connected to the pole, depending on the type of pole, the service may be replaced. This means that the unit rate we use in our modelling is higher than that used in the AER model, which uses RIN data. When we report the repex on poles in the RIN, we remove the cost of any service replacements that occurred at the same time as the pole, and the cost of the service replacement is allocated against the repex for services.

Service lines

Our forecast expenditure for service lines is significantly below the amount suggested by the AER's model. This is because our model assumes that (as a prudent and efficient business) we replace a significant proportion of service lines when we replace other assets, such as poles or cross-arms. That is, our forecasts for service lines reflect a residual amount of expenditure that results from subtracting the estimate of the service lines that can be replaced during other work from the estimate of the total number service lines to be replaced in the same period.

This offsets some of the differences in the poles repex model comparisons.

Transformers

The two main reasons for the different outcomes between the AER's model and our transformer forecast are that the AER's model uses a significantly lower unit rate and excludes some expenditure:

- *A significantly lower unit rate*: The volumes reported in the annual RIN for distribution transformers is the number of jobs undertaken on transformers per year. This is a combination of replacement of components of the transformer assembly and complete transformer replacements. Consequently, the unit rate for the cost of transformer replacement works is significantly lower than the NEM median rate, and results in a calibrated replacement rate that is significantly higher than the whole transformer replacements forecast.
- *Exclusion of some expenditure*: When reporting repex in the annual RIN, major power transformer refurbishments are reported under 'Transformers – Other', which does not have a corresponding age profile. Consequently, this expenditure is not included in the AER's model but should be.

Switchgear

One of the key challenges associated with modelling switchgear repex is calculating a meaningful unit rate. This issue is particularly acute at 22 kV because:

- there is a range of equipment that could require replacement from pole-mounted units to ring main units within ground mounted distribution substations to individual outdoor circuit breakers within zone substations and indoor switchboards containing multiple circuit breakers; and
- the replacement costs of any given item varies from tens of thousands of dollars to over a million dollars.

In addition, within zone substations, an outdoor 22 kV circuit breaker may be replaced by another outdoor circuit breaker at the end of its life or it may be replaced by an indoor switchboard, depending on the number and condition of circuit breakers at a site. The availability of different replacement options therefore makes modelling complex.

Finally, switchgear refurbishments are reported in the RIN under 'Switchgear – Other' which does not have a corresponding age profile, so this expenditure is not included in the AER's model. This expenditure should be included as historically, this line item has constituted about 22% of total repex for switchgear.

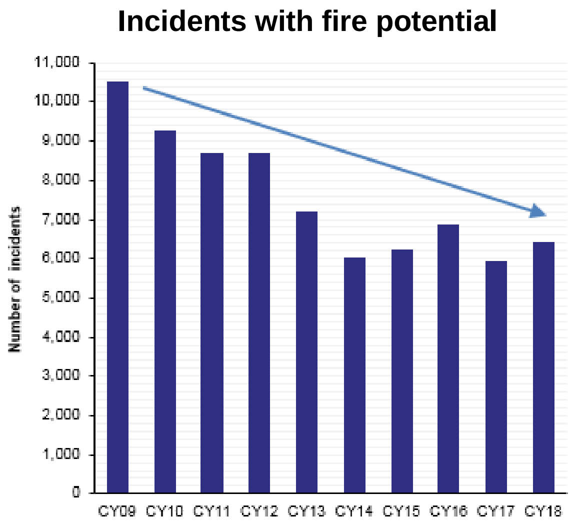
9.9 Safety capital expenditure

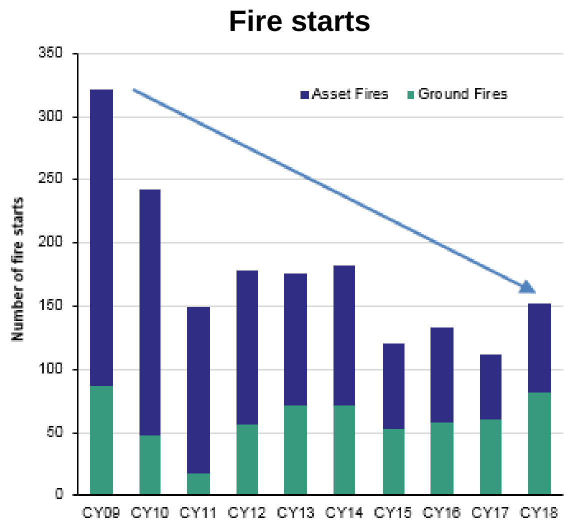
9.9.1 Overview

Safety has been a significant driver of expenditure over the last decade, most notably in response to the VBRC recommendations and our self-initiated programs aimed at improving safety. Our safety programs ensure that the community benefits from a materially lower safety risk.

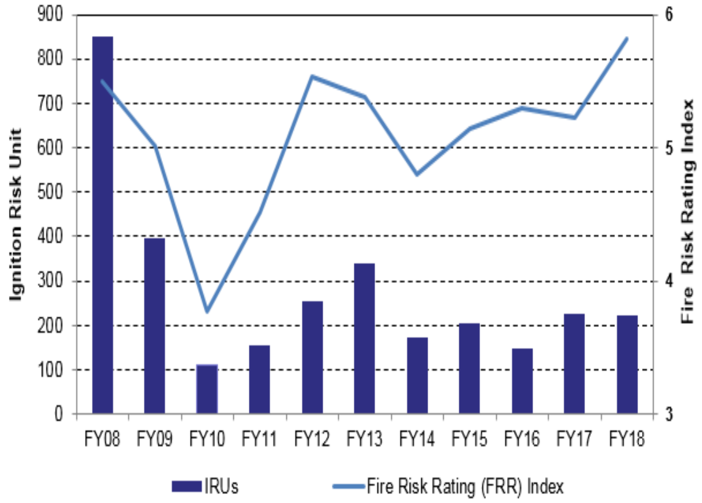
As shown in the figures below, since 2009, the number of incidents with the potential to cause a fire and the actual number of fire starts caused by our assets has fallen absolutely and on a risk adjusted basis. These figures also suggest that despite weather conditions worsening we have been able to keep the number of fires down.

Figure 9-21: Safety Performance





Ignition Risk Units vs Fire Risk Rating Index



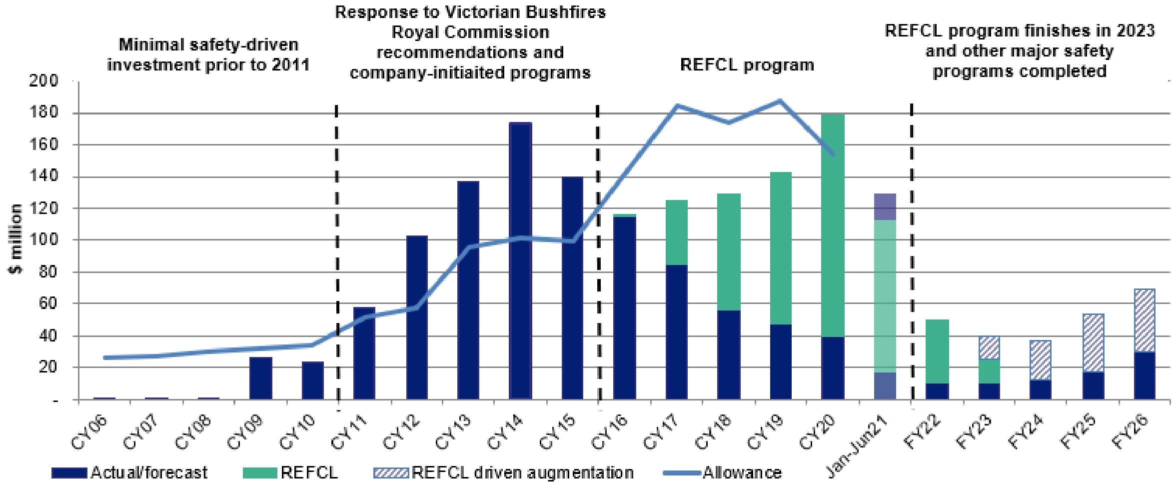
Note 1: Under current arrangements, each fire is weighted by a "location factor" and a "fire risk (timing) factor". By applying these weighting factors to each fire, a fire will have a score called an "ignition risk unit" (IRU). As is demonstrated, the IRU has fallen sharply over the last decade.

Note 2: The Fire Risk Rating (FRR) is a risk weighted index of weather elements indicating how conducive the prevailing weather conditions are to ignition.

Safety capex (including the REFCL project) is forecast to be $249.9 million ($2021) over the 2022-26 regulatory period. As shown in the figure below, this is 64% lower than our expected safety expenditure in the current regulatory period. However, this reduced expenditure does not reflect a lessening of our commitment to safety. Rather, the reduction reflects the completion of the mandated REFCL program, which has required significant investment, in 2023. The reclassification of conductor and cross-arm replacement as repex rather than safety (due to them returning to business-as-usual replacement levels), also accounts for a significant reduction in forecast safety capex.

The figure below shows our actual and forecast safety capex between 2006 and 2026.

Figure 9-22: Safety capex 2006 to 2026, incl. overheads ($m, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

9.9.2 Key drivers

Community expectations about the safety of our services and assets drive our safety capex, which are reflected in:

- Our safety vision, missionZero;
- The *Electricity Safety Act* and regulations made under the Act;
- Our approved Electricity Safety Management Scheme (ESMS); and
- Our approved Bushfire Mitigation and Vegetation Management Plans.

9.9.3 Projects and programs of work

The table below summarises the principal projects and programs of work that we have classified as safety capex. It shows our proposed expenditure over the 2022-26 regulatory period and the percentage of total safety capex by project/program.

Table 9-7: Safety capex projects and programs for the 2022-26 regulatory period, direct costs ($m, 2021) and %

Project/Program	Total $M	% of total
REFCL installation program	49.5	22%
REFCL ongoing compliance	97.8	43%
Codified Areas - Proactive insulation / undergrounding	35.4	16%
Codified Areas - SWER/bare conductor replacement	5.5	2%
EDO fuses	23.2	10%
Other	13.8	6%

Project/Program	Total $M	% of total
Total	**225.3**	**100%**

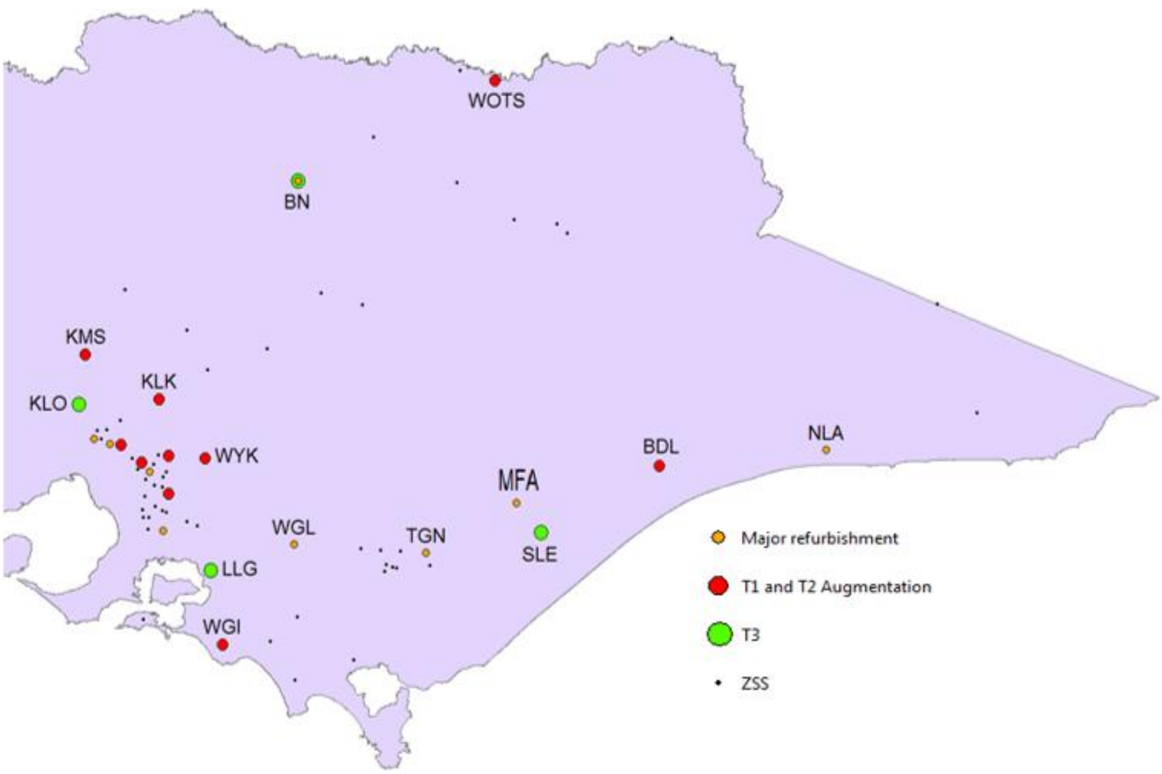
Further detail on our largest safety programs is below.

9.9.3.1 REFCL installation program

The installation of REFCL technology is delivering bushfire mitigation benefits to Victoria and our customers. The program is a world first in using REFCL technology to mitigate bushfire risk.

We are subject to a regulatory framework that sets challenging protection performance standards at 22 zone substations (see Figure 9.24). Presently, we can only meet those standards by installing REFCLs and undertaking significant remedial work on the network to enable the safe and effective operation.

Figure 9-23: Location of REFCL stations and major repex stations (Victoria)

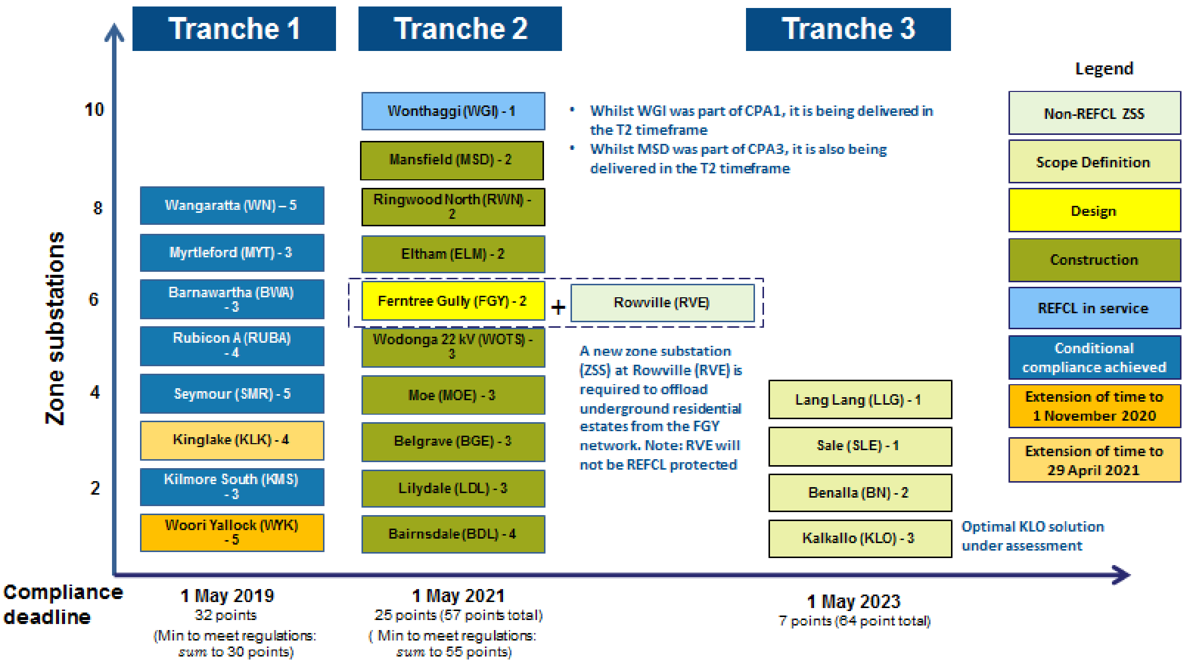


Note: ZSS identifies the location of our zone substations, T3 identifies locations where we are installing the third tranche of our REFCLs, T1 and T2 Augmentation identifies locations where we have installed REFCLs through the first and second tranches of the REFCL program, and Major refurbishment identifies locations where we are undertaking non-REFCL related capital projects.

When the AER published its final decision for the 2016-2020 regulatory period it anticipated the introduction of new bushfire mitigation regulations. Recognising this, and recognising that the costs of installing REFCLs were uncertain, the AER included a 'contingent project' in our 2016-20 determination. This allows the AER to amend our determination to include additional expenditure for us to undertake the contingent project once certain pre-conditions are met, including that the relevant capital works forming part of the program tranche are fully scoped and costed.[53]

The REFCL program has progressed in three tranches complying with the milestones prescribed in regulations, as illustrated in the figure below. The regulations attribute points to each zone substation – with higher points allocated to those zone substations where REFCL installations will have the greatest benefit in terms of mitigating fire risk. The points attributed to each zone substation are shown in the figure below.

Figure 9-24: REFCL location and timing of implementation



Note: Current at November 2019.

The AER accepted our forecast capex for the installation of the first REFCL at Woori Yallock (shown in orange) as part of the 2016-20 determination. Subsequently, the AER amended the 2016-20 determination in accordance with the contingent project provisions in the Rules to provide a cost allowance for Tranche 1, 2 and 3 of the REFCL program. For example, in May 2019, the AER considered the Contingent Project Application (CPA) for Tranche 3 of the REFCL program and adjusted our expenditure allowance to account for expenditure that we will incur during the current regulatory period.

This regulatory proposal is consistent with the capex forecasts approved by the AER for Tranche 2 and Tranche 3 REFCL program expenditure in the 2022-26 regulatory period.

The AER's decision on Tranche 3 did not approve our preferred solution for the Kalkallo zone substation.[54] However, the AER did recognise that we may wish to pursue our preferred solution, instead of the solution approved in its decision. An important element of the AER's decision to reject our preferred solution was that we had not received the necessary legislative exemptions to be able to implement it. We are currently pursuing these exemptions with the ESV and, if approved, we will change our proposal to reflect our preferred solution.

[53] Australian Energy Regulator, Final Decision, AusNet Services distribution determination 2016 to 2020, Attachment 6 – Capital Expenditure, May 2016, pp. 6-126 – 6-127.

[54] ASD - WSP - REFCL compliance at Kalkallo and Coolaroo - 111219 – Public.pdf.

As highlighted in the figure above, most of the work associated with REFCL is completed in Tranche 1 and 2, which we expect to be complete prior to the start of the 2022-26 regulatory period. This will deliver a significant reduction in bushfire risk, which will benefit customers and the wider community for years to come. A final project Final Project Assessment Report for Tranche 1 of the REFCL program has been completed.[55] Given the initial roll out of the REFCL program is due to be completed by 1 May 2023, the relatively low level of capex being proposed for the 2022-26 regulatory period ($49.5 million (direct, $2021)) is appropriate and reflects the significant investment that has already occurred.

9.9.3.2 REFCL ongoing compliance program

For a REFCL to operate with the required sensitivity as specified in the regulations, the capacitive balance of the circuits connected to the REFCL and the total capacitance of the connected circuits, must be maintained within specified ranges. Our Tranche 1 and Tranche 2 programs installed REFCLs to meet the performance standards, given the network conditions that existed at the time. This prudent and efficient approach avoided installing additional REFCLs that were not economically justified at the time. Since our CPAs for Tranches 1 and 2 were approved, natural growth in the network, the ongoing undergrounding and insulation in Codified Areas (see below), and modifications to existing customer connections, is increasingly impacting both the capacitive balance and adding to the total connected capacitance. Therefore, to maintain the mandated performance standards specified in the Electricity Safety (Bushfire Mitigation) Regulations 2013, we need to augment our network in selected areas.

We have developed a capacitance forecast to determine when augmentation solutions will be required to ensure that existing REFCLs remain operational and compliant. The forecasts were prepared following a capacitive current forecasting methodology developed by us with input from The Centre for International Economics (The CIE).

The REFCL's ability to successfully detect, manage and locate phase-to-earth faults on the 22kV network is dependent on a complex combination of network conditions, including the network damping factor and the network topology. When correctly managed, the balance of these network conditions allow continued operation of the REFCL protection in compliance with the required capacity. Currently, the actual damping characteristics specific to the network can only be measured once a REFCL is operating. At locations where a REFCL is not yet operational, an ASC planning limit of 100A is assumed. While generally conservative this is used to identify the works required to maintain compliance in the 2022-2026 regulatory period.

The conservative ASC planning limit has identified the need for the augmentations towards to start of the period. However, our proposed expenditure program has been spread throughout the 2022-2026 regulatory period, which allows for the conservative nature of this estimate.

These augmentations are likely to include the installation of additional ground fault neutralisers, new transformers and, in some instances, the construction of new zone substations. The forecast cost of these augmentations is $97.8 million (direct, $2021). We have classified this expenditure as safety expenditure, given it is required to maintain the mandated performance standards specified in the Regulations. This REFCL augmentation comprises:

- Kilmore South zone substation – Upsize the arc suppression coil (ASC);
- Wonthaggi zone substation – Replacing a power transformer and installing a Ground Fault Neutraliser (GFN), resulting in Wonthaggi becoming a two GFN site;

[55] AusNet Electricity Services Pty Ltd, Non-network options to comply with Bushfire Mitigation Regulations RIT-D Final Project Assessment Report, October 2018.

- Ringwood North zone substation – Installing an additional GFN, resulting in Ringwood North zone substation becoming a two GFN site;
- Wodonga Terminal Station – Building a new zone substation and installing one GFN and extending a 66 kV line by 22 km;
- Eltham zone substation – Building a new zone substation, installing one GFN, extending a 66 kV line by 5.5km and a 22 kV augmentation;
- Bairnsdale zone substation – Building a new zone substation and installing one GFN;
- Lilydale zone substation – Installing an isolation transformer and undergrounding works at Mt Dandenong; and
- Belgrave zone substation – Load transfers and network augmentation (feeder re-conductoring and reconfigurations).

Detailed planning reports have been prepared for each project.[56] We are also building a new zone substation at Rowville, which is required prior to 2021 to ensure continued compliance with our REFCL obligations. As we will construct that substation during the current regulatory period, we will absorb the associated cost within the current period, and note that the expenditure for Rowville is not included as forecast capital expenditure in this proposal. Similarly, there are two projects in the current regulatory period to reduce capacitance to an acceptable level at Kinglake and Worri Yallock, which were not contemplated in the Contingent Project Applications. We are absorbing the associated cost within the current period.

Contingent Projects and unspent capital expenditure

The treatment of contingent projects that cover multiple regulatory periods is in part dealt with by clause 6.5.7(g) of the NER, which requires that:

> *(g) Subject to paragraphs (ga) and (j), a Distribution Network Service Provider's regulatory proposal for the second regulatory control period must include in the forecast of required capital expenditure referred to in paragraph (a) an amount of any unspent capital expenditure for each contingent project as described in subparagraph (f)(2), that equals the difference (if any) between:*
>
> *(1) the total capital expenditure for that contingent project, as determined by the AER in the first regulatory control period under clause 6.6A.2(e)(1)(ii); and*
>
> *(2) the total of the capital expenditure actually incurred (or estimated capital expenditure for any part of the first regulatory control period for which actual capital expenditure is not available) in the first regulatory control period for that contingent project.*

Further, Clause 6.5.7(h) requires that:

> *(h) The AER must include in any forecast capital expenditure for the second regulatory control period which is accepted in accordance with paragraph (c) or substituted in accordance with clause 6.12.1(3)(ii) (as the case may be) the amount of any unspent capital expenditure calculated in accordance with paragraph (g).*
>
> *In respect of Tranche 3 of the REFCL program, we anticipate unspent capex of $17.7 million direct ($nominal). This unspent capex is the result of the difference in timing between the contingent project allowance approved by the AER and the expected timing of expenditure during*

[56] WOTS REFCL Compliance Maintained Planning Report - AMS 20-400.pdf, WGI REFCL Compliance Maintained Planning Report - AMS 20-401.pdf, RWN REFCL Compliance Maintained Planning Report - AMS 20-402.pdf, LDL REFCL Compliance Maintained Planning Report - AMS 20-403.pdf, KMS REFCL Compliance Maintained Planning Report - AMS 20-404.pdf, ELM REFCL Compliance Maintained Planning Report - AMS 20-405.pdf, BGE REFCL Compliance Maintained Planning Report - AMS 20-406.pdf, BDL REFCL Compliance Maintained Planning Report - AMS 20-407.pdf.

the remainder of this regulatory period.[57] The mechanism in clause 6.5.7(h) predates the implementation of the CESS[58] and appears to have been developed to ensure there is a strong incentive to underspend the contingent project allowance.[59] We consider the CESS is now the more appropriate mechanism to account for the unspent capex in the current regulatory period (and the likely corresponding overspend in the forthcoming regulatory period). Therefore, we have not included this unspent capex in our forecast capex for the 2022-26 regulatory period, as doing so would double up on incentive benefits for the forecast underspend in the current regulatory period.

9.9.3.3 Codified Areas – proactive insulation and undergrounding

The 22 kV overhead network in Codified Areas will be protected by REFCL technology. However, REFCLs provide no protection against fire starts caused by SWER lines.

Codified Areas are areas of high bushfire risk, as defined under the *Electricity Safety Act 1988*. The VBRC and the subsequent Safety Taskforce both recommended undergrounding or insulating SWER lines in Codified Areas over a 10-year time period.[60] While timeframes for this recommendation were not taken up in Victorian legislation, they did establish replacement rate expectations with their investment in the PRF.

During the current period, the PRF provided a significant amount of expenditure ($74 million) to businesses to replace these assets. This program has led to material reductions in bushfire risk in these areas.

Our current condition-based replacement forecast is that 7 km (equivalent to 1%) of the total SWER conductor in Codified Areas in our network area will reach end of life during the 2022-26 regulatory period. While we have included this condition-based replacement in our forecast, we do not consider that limiting the rate of replacement to 1% of the SWER conductor in Codified Areas over the five years meets the expectations of our customers and stakeholders. We are, therefore, proposing an additional program to proactively insulate or underground SWER conductors in Codified Areas.

The proposed program, with a forecast cost of $35.4 million (direct, $2021), will continue the work carried out during the current period under the PRF. However, as much of the conductor is in better condition than anticipated, we are proposing a 20-year replacement program, which is longer than the 10-year period recommended by the VBRC.

The figure below demonstrates that while the proposed program will continue to reduce bushfire risk in Codified Areas, it is a significant step down from the volume of work carried out in the current period under the PRF. Our proposed expenditure profile, which involves a gradual pick-up in proactive SWER replacement in Codified Areas also balances our customers' affordability concerns with our commitment to meeting the community's expectations around bushfire safety risk.

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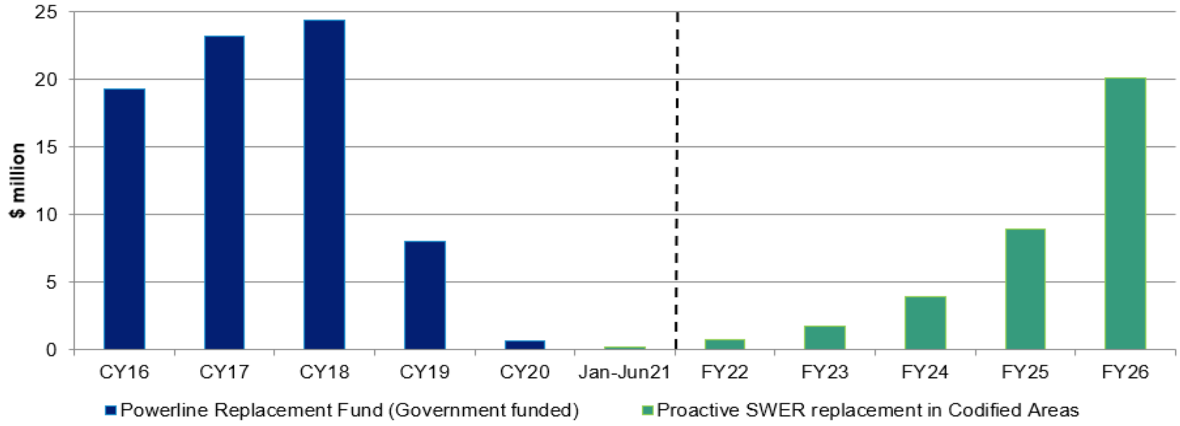
57 Tranche 1 and Tranche 2 of the REFCL program have higher expenditure than the allowance provided in the Contingent Project Applications and so there is no relevant unspent capital expenditure.

58 National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 No 9.

59 AEMC, Draft Rule Determination, Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, p. 80.

60 The Electricity Safety (Bushfire Mitigation) Regulations 2013 require all new and replacement (≥4 consecutive spans) powerlines be constructed with insulated or covered wire.

Figure 9-25: Powerline Replacement Fund expenditure and the proposed Codified Areas SWER Powerline Replacement Program, direct capex ($m, 2021)



Source: AusNet Services

Our proposed program will therefore replace approximately 110 km (17%) of the 660 km of SWER network in Codified Areas over the regulatory period with insulated overhead conductor (70%) or undergrounding (30%). This 110 km includes the 7 km condition-based replacement outlined earlier. This will make a significant contribution to our ongoing plan to replace the bare conductors remaining within Codified Areas. Further information on this proposed program is available in the Codified Area Strategy provided in the supporting documentation accompanying this proposal.

9.9.3.4 Codified Areas – Condition-based SWER/bare conductor replacement

As discussed in the section above, we are proposing to replace around 110 km of SWER and bare conductor in Codified Areas during the 2022-26 regulatory period, based on the condition of some of those conductors as well as the safety risk presented by those assets. The forecast cost for these replacements is $5.5 million (direct, $2021).

9.9.3.5 Expulsion drop out fuses

The operation of expulsion drop out (EDO) fuses can result in the expulsion of hot material, increasing the risk of bushfire ignition. They remain the largest cause of fires associated with asset failures. EDO fuses are therefore considered high risk, and a substantial targeted replacement program was established to mitigate that risk. Our proposal for the 2022-26 regulatory period sees us continuing our current EDO fuse replacement program and the replacing approximately 1,750 EDO fuses per annum. This compares to the 2,900 EDO fuses that we expect to replace annually in the period 2016-20. The forecast cost for these fuses is $23.2 million (direct, $2021).

9.9.4 Benchmarking and validation

As explained above, we have extensive information to demonstrate that the proposed scope of work in Tranche 3 of the REFCL program and the estimated costs for each zone substation are prudent and efficient. The AER is familiar with both the project scope and how we estimate costs, with it previously having reviewed and approved contingent project applications for the first two tranches of the REFCL program.

In relation to the other safety projects and programs, the actual costs of undertaking similar work during the 2016-20 regulatory period are the basis of our estimated costs.

It is difficult to benchmark 'safety' related costs, as DNSPs do not typically report 'safety capex'. We also recognise that, from a benchmarking perspective, the category is problematic as DNSPs are likely to apply different approaches when allocating these costs, particularly as significant proportions of repex is safety-related. In addition, we are subject to a number of legislative and regulatory obligations to make safety improvements, such as our general obligation to minimise as far as practicable hazards and risks on our supply network.[61] In this sense, benchmarking expenditure with a view to limiting the AER's allowance would be inconsistent with our regulatory obligations.

As already noted, our forecast safety capex is substantially lower than our historical spend. Regardless of this reduction, the proposed expenditure represents the prudent and efficient costs we will incur in meeting our current safety obligations.

9.10 Connections capital expenditure

9.10.1 Overview

Customer connection expenditure is the capital investment associated with connecting new customers to the shared electricity network at the customer's request. In some circumstances, a significant proportion of capital is recouped from connecting customers, and any remaining costs recovered from the rest of our network customers through tariffs. Only the net capex, being the difference between total connection capex and capital contributions received from customers, is included in our regulatory asset base. This chapter should be read in conjunction with our connections policy[62] and Model Standing Offers which can be found on our website.[63]

We are forecasting gross and net connections capex to be $352.3 million ($2021) and $210.2 million ($2021) respectively over the 2022-26 regulatory period. For net connections this is 19% lower than expected net connections capex ($260.7 million ($2021)) in the current regulatory period.

Following our adoption of the national charging framework (under Chapter 5A of the NER) in 2016, we amended our policy governing the funding arrangements with residential land developers under turnkey arrangements. Under our new policy, land developers no longer receive rebates for constructing LV assets. Instead, we recognise the market value of constructed assets upon completion, i.e., the value of assets gifted to us from developers on a "per lot" basis. Our forecasts, therefore, reflect the expected volume of residential subdivisions under turnkey arrangements multiplied by an agreed unit rate per lot for gifted assets.

Our gross capex and customer contributions forecasts also incorporate several large generator connections currently under development, including the Cherry Tree Wind Farm and Wangaratta Solar Farm. We expect the generator proponents to fully fund these projects and as such, we make no provision for generator connections in our net capex forecasts. These connections will not, therefore, impact future prices paid by our network customers.

Our historical and forecast gross and net connections capex is shown in the figure below. However, we intend to provide updates in our Revised Revenue Proposal to reflect updated data, including:

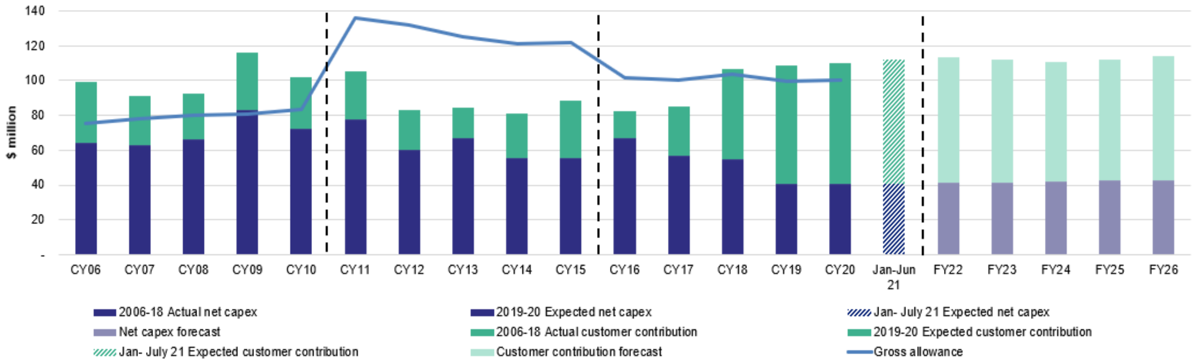
- the latest rate of return, which is used to discount incremental revenue in the calculation of customer contributions towards residential and business connections;
- updated customer number forecasts for residential and business connections;
- updated pipeline of large Co-generation connections; and
- updated unit rates for various types of connections including our 2019 actual unit rates.

61 *Electricity Safety Act 1998*, section 98.

62 Draft Distribution Connection Policy Effective from 1 July 2021.

63 See: https://www.ausnetservices.com.au/New-Connections/Electricity-Connections (accessed 16 January 2020).

Figure 9-26: Gross & net connections capex and contributions 2006 to 2026, incl. overheads ($m, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

The figure above shows that our forecast of net connections capex over the 2022-26 regulatory period is steady, at an annual average of approximately $42 million ($2021). From 2018 onwards, our capital contributions have increased due to the policy changes described above. The implications of this change are that, compared to historical levels, connecting customers now pay a larger proportion of the connection capex, thus reducing the proportion that is funded by the wider customer base.

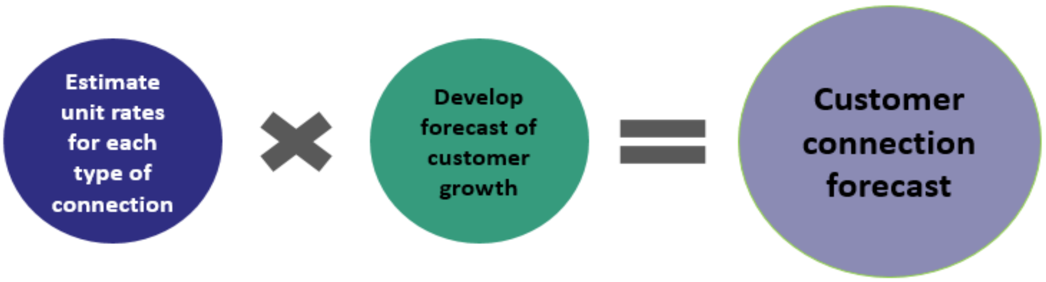
9.10.2 Key drivers

In broad terms, as customer connection capex comprises connection assets, which are specific to that customer connection, and network augmentations to strengthen the network to facilitate a customer connection, the key drivers for connections capex are:

- the number and type of new load connection requests, which are forecast in Chapter 7;
- the expected growth in demand as a result of the new connections; and
- the available network capacity, particularly in the growth corridors where the new connections are expected.

Our connections capex forecast reflects the efficient level of investment required to ensure that we can meet our customers' demand for new connections and maintain network reliability. Our total forecast connection expenditure is the product of our expected customer volumes and connection unit rates (see the figure below).

Figure 9-27: Customer connections forecasting approach



We forecast customer growth for residential, small business, commercial and industrial categories, while our unit rates are based on similar connection types for most categories of connection. For connection categories where the average cost per connection fluctuates due to variations in the complexity and relative size of projects undertaken in a given year, we use a longer-term average unit rate in the forecast. This is the case for complex residential connections (particularly in rural areas) and larger commercial and industrial connections, where we have used a historical average unit rate based on actual costs between 2013 and 2018.

The table below summarises our approach to forecasting each category of connections expenditure.

Table 9-8: Forecasting approach for each category of new connections

Connection category	Unit rate	Volume
Medium Density Housing	Where a third party constructs and developer gifts assets to us: • Gifted LV Assets - at agreed unit cost per lot (subject to annual CPI inflation) • HV Rebates - at 4-year historical average unit rate (2015-18) Where we design and construct we use the 2018 calendar year historical unit rate	Historical proportion of forecast residential connections
Underground Service Installation	2018 calendar year historical unit rate	Historical proportion of forecast residential connections
Business Supply Projects	5-year historical average unit rate (2014-18)	Historical proportion of forecast non-residential connections
Complex Residential Supply Projects	5-year historical average unit rate (2014-18)	Historical proportion of forecast residential connections
Low Density Housing - Subdivision	3-year historical average unit rate (2016-18)	Historical proportion of forecast residential connections
Private Electric Line Replacement	5-year historical average direct costs incurred (2014-18)	N/A - forecast driven by historical costs incurred
Cogeneration Projects	Forecasts of expected volume of generation connections over the 2019-25 period is based on a pipeline of projects that we update on a regular basis. Since these connections typically involve network extensions in the 66 kV network, the costs are significant. We note that we have two active regulated generation projects in construction (wind and solar) and we have received several applications for further connections in the 2022-26 regulatory period.	N/A - forecast at project level

9.10.3 Projects and programs of work

The table below shows the key connection projects and programs for the 2022-26 regulatory period, showing the proposed expenditure over the forecast period and the percentage each category contributes to this expenditure category.

Table 9-9: Connection projects and programs for 2022-26, direct costs ($m, 2021) and % of total connections expenditure

Category	Total $M	% of total
Medium Density Housing	221.0	42%
U/Ground Service Installation	61.6	12%
Business Supply Projects	109.9	21%
Complex Residential Supply Projects	34.8	7%
Low Density Housing - Subdivision	33.6	6%
Private Electric Line Replacement	5.8	1%
Cogeneration Projects	62.9	12%
Total	**529.6**	**100%**

9.10.4 Benchmarking and validation

As explained above, our forecast connection capex is the product of our customer growth projections and the applicable unit rates. The total connection capex is a mix of simple and complex connections that need to be factored into the forecasts.

In terms of benchmarking, our unit rates are derived from historical data, which reflect the conditions on our network and capture efficiency improvements. The use of historical rates provides a strong assurance that the proposed connection capex is prudent and efficient.

In relation to customer numbers, these projections are developed using a detailed 'bottom-up' and 'top-down' modelling approach, as described in Chapter 7. The robustness of this forecasting approach supports the use of the customer number projections in relation to the connection capex forecasts.

9.11 Augmentation

9.11.1 Overview

Augmentation capital expenditure (augex) is the capital needed to expand network capacity, including that associated with DER.

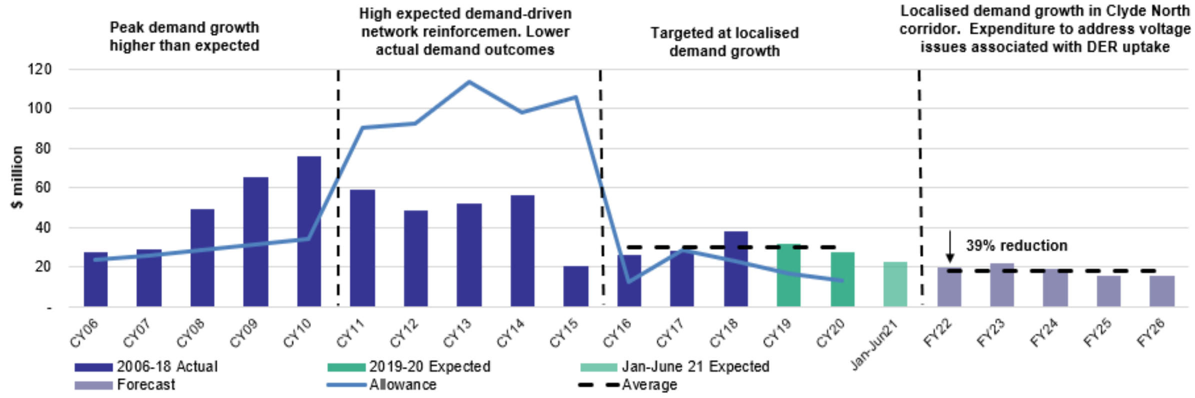
We are forecasting augex of $92.2 million ($2021) over the 2022-26 regulatory period, which is over a third lower (39%) than the augmentation expenditure we expect to incur in the current regulatory period. However, a new VCR was published in late December 2019 (see section 9.5) and we may need to revisit our augex forecast in our revised proposal.[64]

Our forecast for the 2021-26 regulatory period includes $8 million ($2021) for a major augmentation project at the Clyde North zone substation that we agreed with the Customer Forum. This project is necessary to address network constraints in a key growth corridor and ensure continued reliable energy supply.

The $8 million ($2021) proposal agreed for the Clyde North zone substation represents a significant ($4.7 million ($2021) reduction to the augex proposal that we initially discussed with the Customer Forum. It comprises $7.8 million ($2021) for the 2022-26 regulatory period and $0.2 million ($2021) for the period 1 January 2021 to 30 June 2021.[65]

The figure below shows our actual and forecast augex over the period 2006-26.

Figure 9-28: Augmentation capex 2006 to 2026, incl. overheads ($m, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

9.11.2 Key drivers

The key drivers for augex are:

- the need to ensure network performance meets our customers' requirements, given the increasing penetration of DER and the challenges this poses for us in complying with mandatory voltage standards;
- demand growth forecasts; and
- new load connection requests driven by new customer connections.

9.11.3 Projects and programs of work

In addition to the augmentation project at the Clyde North zone substation, our primary augmentation projects and programs are:

- upgrading or installing new feeders to address demand growth in parts of the network;
- upgrading the network to address voltage compliance issues as a result of DER growth;
- expanding the capacity and voltage management for the low voltage network, including to address the impact of solar exports on the network; and

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64 The VCR plays a pivotal role in network planning and investment.

65 As noted earlier, all aspects of this proposal have been considered by the Customer Forum, including changes due to moving to a financial year regulatory period and the application of updated inflation assumptions.

- customer supply compliance.

The table below summarises the key augmentation projects and programs for the 2022-26 regulatory period, including the proposed expenditure over the forecast period and the percentage each project/program contributes to this expenditure category.

Table 9-10: Augmentation projects and programs for the 2022-26 regulatory period, direct costs ($m, 2021)

Project/Program	Description	Total $M	% of total
Clyde North	As explained in section 9.7.1, this project would increase the network capacity to supply the strongly growing customer base and associated demand in Clyde North	7.8	9%
Central Region Feeder projects	These projects address demand growth in a limited number of locations.	10.6	13%
Summer Network Readiness Program	The purpose of this program is to prepare the HV network for the expected peak demand in the upcoming summer period.	2.7	3%
Customer Supply Compliance Program	This program addresses customer complaints on power quality. This is mainly voltage compliance, but may include other power quality issues.	6.0	7%
Eliminating Network Operational Deficiencies	This program rectifies operational deficiencies that are identified when work is undertaken on the network (eg identifying locations where the installation of a switch may minimise the impact on customers of undertaking maintenance work).	1.4	2%
LV Network Capacity	This program identifies and addresses emerging overloads in distribution transformers and low voltage circuits that arise due to changes in customer load and generation profiles.	11.4	14%
Hosting Capacity for DER	This is a new program to address emerging constraints associated with the increasing penetration of DER. The program targets augmentations to accommodate additional DER where this	20.9	25%

Project/Program	Description	Total $M	% of total
	investment is economic, taking into account the value of 'spilt' generation.		
Voltage Compliance Program	This is a pro-active, prioritised program to address the feeders that are least compliant with AS61000.3.100 'Steady state voltage limits in public electricity systems'. The compliance issues are partially driven by the growth of DER connections to the network. The program is prioritised to address the worst served customers in the most efficient manner.	20.6	25%
Other	Expenditure to carry out minor feeder augmentation in the Eastern and Northern regions. Installation of meters for Power Quality Monitoring.	6.2	7%
Efficiency adjustment	This is a downward adjustment to reflect deliverability efficiencies across the augex portfolio (a similar adjustment has been made to our proposed repex portfolio).	-4.5	-5%
Total		**83.1**	**100%**

We discuss some of these proposed augmentation projects and programs below.

9.11.3.1 DER program (Hosting Capacity for DER and Voltage Compliance Programs)

We are committed to expanding the opportunity for our customers to connect DER to our network and to maximise the potential of their solar and battery installations. We engaged extensively with the Customer Forum, our customers and stakeholders to develop an approach that focuses on delivering the best value for our customers. This means facilitating efficient investment in DER to better:

- serve the needs of customers, when it is economically efficient to do so; and
- understand and manage the increasing impacts of DER on the network.

Our customers have told us that they do not want to be constrained in their ability to export.[66] That said, we do not consider that our customer base should bear unreasonable costs to guarantee that those customers with solar PV can always export their excess generation.

[66] JWS Research, Community Perceptions Toward Solar and Innovation Propositions, prepared for AusNet Services, September 2019.

The design of our DER program, therefore, ensures adoption of a prudent and efficient approach to maximise the ability of our customers to export electricity. Key elements of our proposal are:

- Mandating that new installations have new inverter technology that allows inverters to dynamically reduce their export when our network starts to become constrained. This technology also enables us to unlock additional capacity and customer value from the existing network;
- Implementing a new technology, called a Distribution Network Optimisation Platform (DENOP), which allows us to use dynamic network control technology to maximise customer exports within the limits created by network constraints. This will require increased IT expenditure of $1.25 million ($2021); and
- Implementing two programs based on the economically efficient amount of augmentation to unlock network constraints:
  - A $20.6 million ($2021) voltage compliance program that focusses on addressing areas of the network that are currently non-compliant with the Code (and currently requires us to limit a number of customers' export capability);
  - A $20.96 million ($2021) forward-looking hosting capacity for DER program that addresses new constraints as they emerge.

These initiatives aim to allow our customers to install solar or DER with fewer restrictions on export capability.[67] If this program is not undertaken, many new DER connections will have limited or no ability to export excess generation. Failing to undertake this program could also result in 235,000 customers (including 95,000 solar customers) experiencing elevated voltages by 2026. This would materially curtail the ability of these solar customers to export and have detrimental reliability impacts on the other customers.

The expected benefits of this program are:

- Enhanced ability for our customers to connect DER and export electricity. This would allow an additional 270 GWh per annum to be exported by 2026 and ensure that nearly 31,000 solar customers would not be export limited to zero;
- Downward pressure on wholesale electricity prices due to additional low marginal cost generation. This benefits all customers;
- Lower carbon emissions and air pollution, again benefiting all customers; and
- Better voltage compliance for 235,000 customers ensuring the safety and stability of the electricity supply.

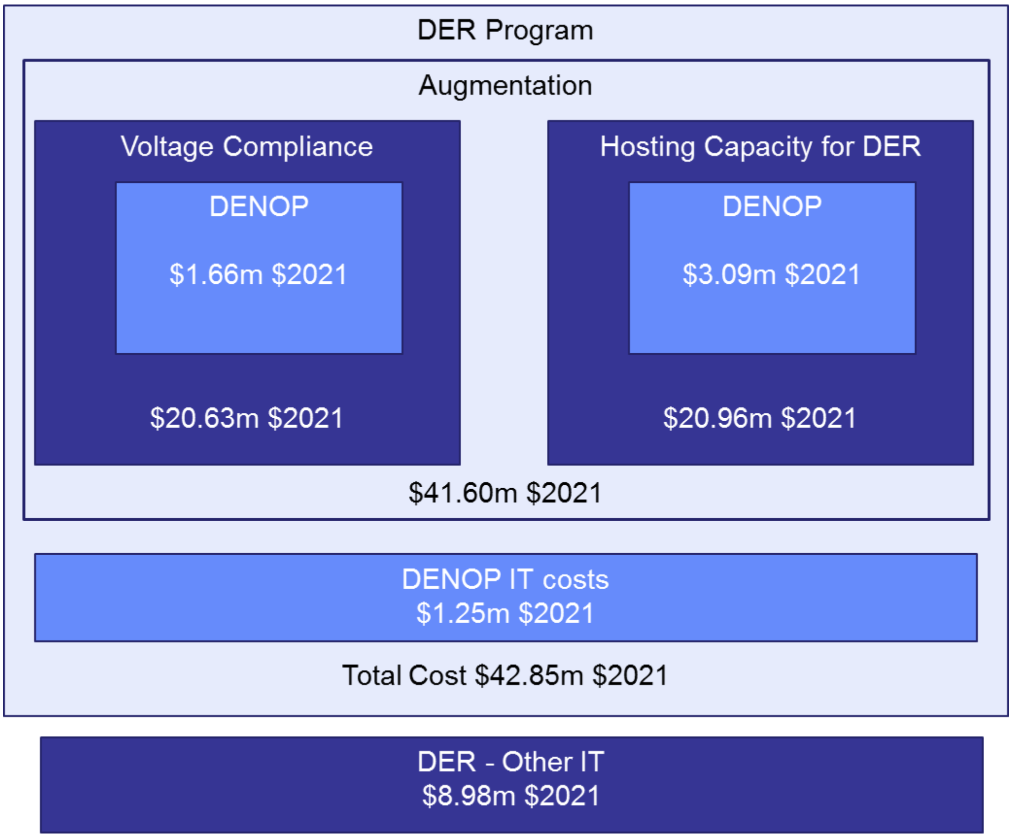
Our DER program comprises two augmentation programs and the necessary ICT expenditure to implement the DENOP smart networks solution. Full details of the augmentation program are the Voltage Compliance Strategy.[68] The DENOP ICT expenditure is explained in section 9.12 and in the ICT DER strategy brief.[69]

67 These initiatives are supported by a modelling approach that identifies the efficient amount of network augmentation based on the additional generation that it enables within our network.

68 AMS 20-50 Steady State Voltage Compliance.

69 Program Brief Distributed Energy Resources PUBLIC VERSION.

Figure 9-29: DER program ($m, $2021)



Source: AusNet Services.

In addition, there is $8.98 million in ICT expenditure to allow for better network management in the face of a changing environment. A key element of this program is to develop a HV/LV model, which will enable us to better plan, integrate and manage the impact of DER. It will enable 'what if' analysis for solar and inverter output. This enables safe operation of the network in an environment of high DER penetration and is explained in the ICT DER brief.

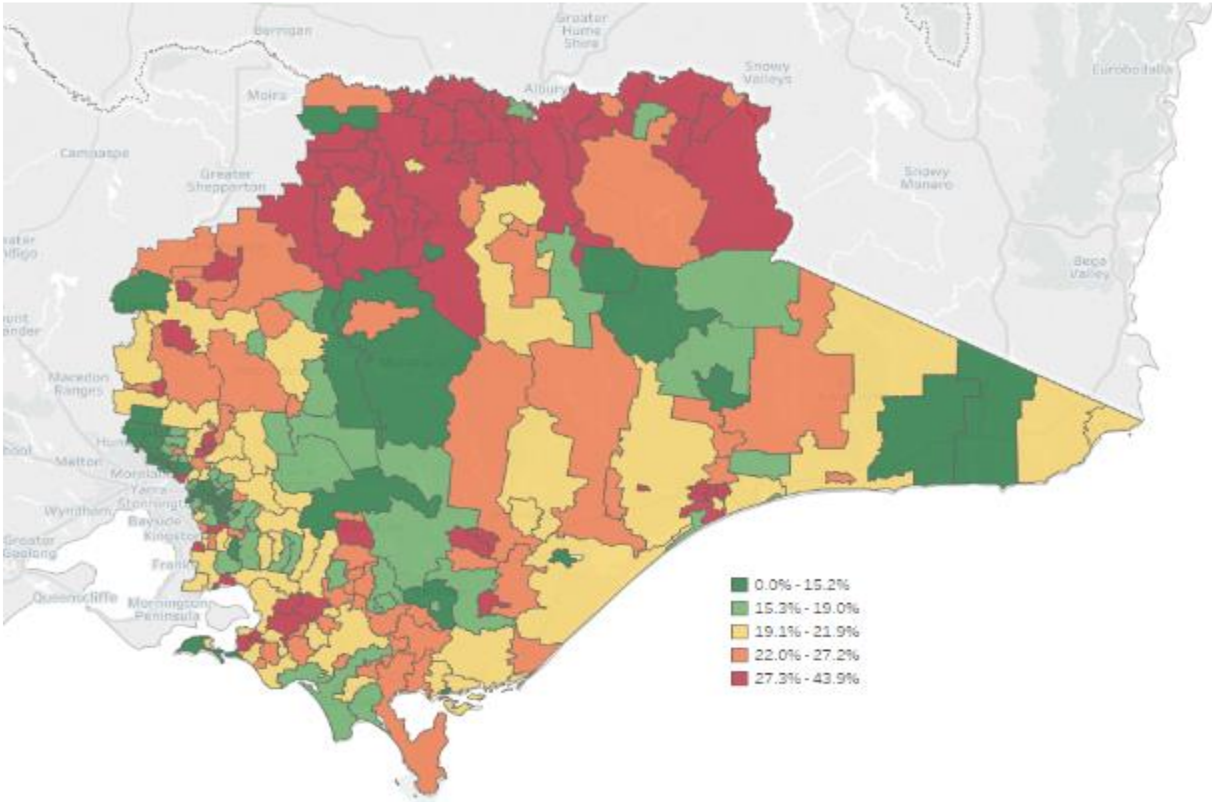
Increasing uptake of DER by customers

DER includes solar rooftop PV systems, batteries, as well as demand response to manage load such as hot water systems, pool pumps, smart appliances and air conditioning control. DER is growing rapidly across the NEM, including within our network area, due to new government policy incentives to encourage uptake of solar systems resulting in:

- cost reductions and shorter payback periods; and
- increased consumer awareness and uptake.

Importantly, as DER uptake is not evenly distributed throughout our network, and as voltage constraints are highly localised, it is possible to hit constraints in any portion of the network. However, constraints are much more common in areas with higher penetration of DER. The figure below shows the variation on residential solar penetration across our network. We have sections of our network that already have solar penetration greater than 27%, which is sufficiently high to cause network constraints. Simplistic assessments of average penetration rates across DNSPs do not sufficiently capture the granular network issues that can arise.

Figure 9-30: Residential solar penetration by postcode (quintiles)



Source: AusNet Services.

In August 2018, the Victorian Government announced its Solar Homes policy. This is a $1.2 billion program to encourage 650,000 Victorian home owners to install solar panels by providing a rebate on installation costs (per household) and low cost finance for the remaining costs.[70] We welcome this policy, as it represented a means to build on the 350,000 rooftop solar installations currently in Victoria and to keep pace with the roll out of these new technologies in Queensland and New South Wales. The Victorian Government's policy, and its popularity with Victorian consumers, means we must ensure we connect and support the additional demand for embedded solar systems. As such, this is the key focus of our DER program in the forthcoming regulatory period.

Our research shows that customers are unhappy and confused by a government policy that encourages them to invest in DER only to be told in some instances that the network cannot allow them to export or even connect.

Therefore, we are currently working closely with the Victorian government to maximise the benefits of the Solar Homes policy for all customers. The early impact of the Solar Homes policy has been significant. We have observed a very large increase in solar connection applications this year. Since the go-live of our new solar portal in March 2019 we have automatically approved 18,130 (95%) applications. In October 2019 we saw the largest uptake of solar applications, passing over 3500 for the month. By the end of 2019 solar connections will have increased by 73% on 2018. While the positive response to the policy is welcome, it also creates new challenges for us to manage. Our role as an electricity distributor in this area is clear. We need to ensure:

- a quick and easy process for our customers to connect DER resources to the network; and

70 Victorian Renewable Energy Target, 2017-18 progress report, Victoria State Government, The State of Victoria Department of Environment, Land, Water and Planning 2018, https://www.parliament.vic.gov.au/file_uploads/VRET_2017-18_Progress_Report_MMCgCM8L.pdf (accessed 6 September 2019).

- the necessary work on the network occurs so that we can keep pace with the change in usage that DER brings.

We recently launched a new online tool to process expedited applications for solar and battery connections. The previous process took far too long, was too bureaucratic and would have cost customers over $5.8 million dollars more if left unchanged (due to increased volumes). Our new online tool means that customers and solar installers, in over 90% of cases, can receive approval for a solar connection immediately.

We need to improve customer experience and ensure that our network can accommodate our customers' demand for DER. This is supported by research we undertook on our customers views[71] and by the AEMC. For example, in its recent Economic Regulatory Framework Review, the AEMC noted:

> *A high DER environment could mean that DNSPs need to alter aspects of their operation, from transporting electricity oneway t*o being platforms for multiple services, facilitating electricity flows in multiple directions and facilitating efficient access for DER so that they can provide the greatest benefits to system as a whole. [72]

Similarly, the AER's consultation paper on assessing DER integration expenditure indicates:

- High volumes of export restrictions are likely to limit how a consumer may participate in energy markets more broadly, constraining consumer choice in energy services, and may lead to inefficient outcomes[73]; and
- There is therefore considerable support for efficiently upgrading our network infrastructure to meet the challenges proposed by increased DER uptake. We have developed a modelling approach to identify the efficient amount of network augmentation based on the additional generation that it enables within our network and consider this is the appropriate framework to assess and forecast the necessary expenditure.

Challenges associated with DER integration

The typical design of Electricity Distribution Systems assumes that electricity flows in one direction, from large generators to the end customer. However, with the increasing and widespread use of DER, electricity networks are required to increasingly cope with bidirectional flows. This particularly causes issues for protection and control equipment, and voltage regulators and distribution transformers with limited tapping range, which are used to maintain voltages within safety and quality limits. This new paradigm can lead to new and different network constraints to those experienced historically and, at times, requires us to place limits on our customers' ability to export their surplus electricity.

Most of our residential network was built to supply 2 kW per house at peak where the typical size of new solar DER systems is closer to 5 kW (and many systems are significantly larger). A particular concern is that the connection of DER changes the daily magnitudes and direction of power flow on our network, which results in large voltage variations and places pressure on infrastructure.

Our technology systems hold only limited real time information about actual power flow on the LV network and we do not currently have the capability to manage low voltage remotely. While having more remote capability could generate some additional benefits, we do not currently consider that a universal roll out of this technology across our (largely rural) network would be prudent at this time.

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[71] JWSResearch, Community Perceptions Toward Solar and Innovation Propositions, prepared for AusNet Services, September 2019.

[72] Economic Regulatory Framework Review, Integrating Distributed Energy, Resources for the Grid of the Future, 26 September 2019.

[73] AER, Consultation paper on assessing DER integration expenditure, 26 September 2019.

However, the merits of using remote capability to collect real time information is an option that we keep under review.

The development of common platforms, communication standards and shared systems may reduce the overall cost and complexity of facilitating DER. Recognising this, we participate in a national DER API Technical Working Group led by the Australian National University to help develop a common and shared API for DNSPs to communicate with DER platforms. Participation in this working group extends across multiple DNSPs, DER equipment providers and technology providers, and takes a view of the international and local standards environment. However, the development of common standards does not eliminate all integration costs of this common solution.

The table below highlights some of the opportunities and challenges associated with DER that are relevant to our customers and our network. Importantly, as our proposed program is underpinned by an assessment of the net benefits, our program ensures that overall our customer base is better off as a result of this program. While the financial benefits from increased DER flow predominately to DER customers, all our customers will benefit from downwards pressure on wholesale electricity prices, reduced carbon emissions and reduced air pollution. Our customer research has also consistently indicated all customers are willing to pay a small surcharge to enable additional solar benefits.

Table 9-11: Risks, challenges and opportunities with DER

Risks and challenges	Opportunities
Customer impact If the network is not appropriately configured to handle DER: customers may install PV and not be able to fully leverage the benefits and associated savings from two way flows and feeding back excess supply they generate to the network; there is the possibility of damaging network assets, causing undue disruptions to supply, such as light flicker from voltage dips; and there is the possibility of damage and a reduced life for customers' household appliances. **AusNet Services impact** Voltage levels exceed those permitted by the Electricity Distribution Code, potentially resulting in fines and undue disruptions to supply. Voltage deviation due to intermittency of generation causes inconsistencies in flows on the network, creating challenges to maintain the reliability and consistency of supply. The variation in flows caused by DER can create thermal overload of assets like conductors and transformers, requiring more frequent and costly upgrades, while	**Customer expectations** DER enables customers to reduce their energy costs and lower household carbon emissions. **Demand management** Opportunity to reduce peak demand and, in turn, reduce the strain on critical network assets, enabling us to defer/avoid significant capital investment. **Reliability support** Opportunity for DER to act as a back-up power supply, thereby improving network performance and customer satisfaction. **Asset utilisation** Opportunity to increase the overall asset utilisation by shifting consumption from peak to off-peak times.

jeopardising the reliability of critical network assets.

Source: AusNet Services.

Economic approach to planning augmentation to address DER-related voltage issues

We have developed an economic approach to valuing the impact of overvoltage on solar generation. Our approach relies on identifying existing and expected voltage non-compliance at distribution substations. When a distribution substation reaches non-compliance we cannot connect further DER without export limiting the new connections. Once a constraint is reached, further export is curtailed, resulting in a lost opportunity to export by potential customers. In a limited number of cases solar cannot be connected at all.

Our approach to forecasting the amount of efficient augmentation is to estimate the cost of the lost solar generation that would need to be constrained to maintain compliance, and compare that to the cost of augmentation options. To apply this approach we:

1. Use AMI data analytics to assess the voltage performance of each distribution substation.
2. Apply a forecast of expected solar penetration to each distribution substation to determine if and when it becomes constrained in the future and the expected additional energy that could be exported (if it was not constrained).
3. Value the expected additional energy using the base feed-in tariff (FiT) as determined by the ESC in its annual review of the minimum feed-in tariff.[74]
4. Compare the constrained expected exported energy per annum to the costs and benefits of a range of potential network and non-network solutions to remove the constraints.
5. Perform a net present value (NPV) assessment to determine the highest NPV option. A potential solution is economic when the value of unserved generation exceeds the cost of the augmentation.
6. Include the preferred option, being the option with the highest NPV benefit, in our expenditure forecasts as the most economic solution.

Our approach to managing voltage levels ensures that our customers' ability to export is maximised – an outcome we know from our broad-based engagement that they value – where it is economically efficient to do so. While ensuring compliance with the Electricity Distribution Code would warrant action, addressing existing voltage constraints through our program is primarily justified on economic efficiency grounds. We examined four options, ranging from 'do nothing' to remove all constraints and have proposed the option with the highest NPV. This is 'Option 3' in the table below and includes two programs:

- Voltage compliance program (to deal with existing voltage issues); and
- Hosting capacity for DER program (to deal with emerging voltage issues).

Our proposed option effectively balances the costs and benefits to our customers and enables significant additional solar generation.

74 See: https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-tariffs-and-benchmarks/minimum-feed-tariff/minimum-feed-tariff-review-2019-20 (accessed 16 September 2019).

Table 9-12: Comparison of the four program options

	Program Option 1	Program Option 2	Program Option 3	Program Option 4
Cost ($ M)	-	18.9	38.1	626.1
Cost per customer ($)	-	23	47	767
NPV Benefit ($ M)	-	53	453	66
Number of customers voltage performance improved by 2025	-	53,000	228,000	235,000
Number of solar customers voltage performance improved by 2025	-	16,000	93,000	95,000
Number of customers without any voltage improvements by 2025	235,000	182,000	7,000	Aiming for 0
Percentage of 2025 customer base without any voltage improvements	29%	22%	1%	Aiming for 0%
Total export enabled of previously unserved generation over 2021-25 (GWh)	0	183	969	1380
% Export enabled of previously unserved generation over 2021-25	0%	13%	70%	Aiming for 100%

Source: AusNet Services.

The reasonableness of using the Victorian feed-in tariff (FiT)

The Victorian FiT is the rate per kW that an electricity retailer pays to its small renewable energy generator customers for electricity they produce and export into the grid. It is calculated using the following components:

- The value of electricity produced by small scale renewable generators, based on the avoided cost of purchasing the same amount of electricity from the wholesale market, accounting for price changes throughout the day and seasonally. This includes the:
    i. wholesale electricity price forecast, both a single rate and time-varying;
    ii. avoided value of network (distribution and transmission) losses;
    iii. avoided ancillary service charges and market fees;
- The avoided social costs of carbon; and
- The avoided human health costs of using carbon.

The reasonableness of the FiT is re-assessed regularly, including:

- in 2017, when the ESC concluded its detailed inquiry into the true value of distributed generation. This included a major body of research examining the energy value and network value of distributed generation; and
- in the ESC's yearly FiT setting process, which includes consultation with the industry.

In undertaking our analysis, we have relied on the extensive and high-quality consultation processes undertaken by the ESC during the 2017 review. We do not consider that replicating that work would be prudent and efficient, nor would it help to keep costs down for our customers. We note that the ESC has now release a draft decision on the FiT to apply from 1 July 2020.[75] We will adjust our proposal to reflect the revised FiT once the ESV has made its final decision.

Given the above, we consider the FiT is a reasonable, industry accepted metric of value, to use for solar exports from small-scale generators. We have therefore used it as a proxy for the value of unserved energy due to voltage non-compliance in our economic assessments of our augex proposals to address voltage issues. We note that the suitability of the FiT for use in economic analysis was considered and supported by Frontier Economics (see attached report), which also undertook the review of the FiT on behalf of the ESC.[76]

Voltage compliance program (to deal with existing voltage issues)

This is a proactive program to address our voltage-related obligations in the Electricity Distribution Code. The program targets customers most affected by our voltage quality issues and aims to achieve functional compliance by 2025. When completed, this project will improve service to all customers (load and DER) already connected to these areas. It will also facilitate additional DER connecting in these areas.

While compliance is one of the drivers of this program, it primarily justified on economic grounds. As a result of these existing voltage issues, existing DER customers are experiencing inverter trips and we increasingly need to export limit any new generation connections. As discussed above, there is a cost on all customers from such curtailment and our proposed program removes these constraints when it is economically efficient to do so.

Currently, around 54,000 customers (both solar and non-solar), experience voltage issues. We are targeting voltage performance levels in accordance with AS 61000.3.100 (Steady state voltage limits in public electricity systems), which requires that 95% of sites must operate within the applicable voltage limits more than 99% of the time. This Standard recognises that occasional excursions from the permitted voltage limits are unavoidable and are not economical or practically possible to prevent.

Capex of $20.6 million ($2021) will allow us to achieve the performance metrics set by the Code and the Australian Standard by targeting economically efficient augmentations. It will also improve the experience of 88% of the customers who are currently affected by voltage issues. It will also reduce constrained exports for these customers by 13%, although there will still be some network constraints at times.

This program will be co-ordinated with the Hosting Capacity for DER program (see below).

Hosting capacity for DER program (to deal with emerging voltage issues)

This is a proactive program that targets areas that we expect will experience constraints or voltage compliance issues during the 2022-26 regulatory period. We are prioritising this project to ensure our customers will have the ability to export excess energy where the cost of us carrying out works is economically efficient.

If we do not take appropriate action to reduce network constraints, we forecast that by 2025 nearly 30% of our customers (around 235,500 customers) will be experiencing voltage issues by the end of the 2022-26 regulatory period. For $20.9 million of capex, we can improve the experience of 97% of these customers and reduce constrained exports by 70%.

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[75] Minimum electricity feed-in tariff to apply, from 1 July 2020, Draft Decision,3 December 2019.

[76] AusNet Services - Expenditure Forecasting Methodology 2021-25 - 21 December 2018.pdf.

As noted in relation to voltage excursions, it would be uneconomic to remove all constraints affecting DER entirely. Our calculations indicate that to achieve zero constraints would cost $626.1 million and would only improve the experience of an additional 7,000 customers on top of our proposed program. We also note that it is not economic to augment SWER lines to enable greater DER exports and that, even if the lines were augmented, customers may continue to face export limits on excess energy.

This proposal is prudent and efficient as it appropriately balances cost and service outcomes for customers.

9.11.3.2 LV network capacity

This program focuses on minimising outages caused by transformer failures and LV fuse operations due to overloads. We have developed advanced techniques to identify overloading of distribution transformers using AMI data and we are in the process of developing techniques to identify fuse overloading. The estimated cost of this proposal is $11.4 million ($2021) during the 2022-26 regulatory period.

9.11.3.3 Customer supply compliance program

This reactive program addresses quality of supply issues identified by customers within our electricity distribution network. It focuses on taking immediate corrective actions in response to customer complaints. The expenditure for this program has been forecast based on historical spend rates. In conjunction with the proactive voltage compliance program, we expect a declining trend in the expenditure for this program. The total cost of the program over the 2022-26 regulatory period is $6 million ($2021).

9.11.4 Benchmarking and validation

We consider comparisons to DER programs in other jurisdictions should be undertaken with caution, for two primary reasons:

1. Victoria (including AusNet Services) has rolled smart meters out to nearly all residential customers. This ensures granular data on voltage levels is available across our network and enables us to base our modelling on a detailed knowledge of the state of voltage compliance in our network. Comparable data is not available in other jurisdictions.
2. At the zone substation level, we have a network utilisation of 66%, compared to 51% for SAPN, 43% for Energex and 39% for Ergon.[77] While greater utilisation reflects the greater efficiency of the Victorian networks, it also means that we face greater restrictions on our ability to incorporate additional solar relative to other jurisdictions. As such, we will encounter material constraints at lower average levels of DER penetration than South Australia and Queensland.

We use a suite of modelling tools/models based on our detailed network data to help us benchmark and validate our DER proposals and the underlying analysis, including:

- the substation health tool;
- the voltage compliance tool;
- the preliminary tactical hosting capacity tool; and
- an economic valuation model.

77 Non-coincident raw adjusted maximum demand summated at the zone substation level divided by the summation of the Zone Substation rating (MVA). Data sourced from 2018 Category Analysis RINS for each DNSP.

Collectively, these tools allow us to identify existing and future areas of constraints, then value both the cost of the constraints on our customers, and the cost of removing them. This serves as a further confirmation that our preferred augex proposals are prudent and efficient.

To validate the outputs from the models listed above, we also tested our key modelling assumptions through sensitivity analysis (see supporting documents for more information).[78]

9.12 Information and communications technology

9.12.1 Overview

Our ICT capex proposal focuses on expenditure to:

- replace and maintain our technology services in an increasingly complex environment;
- meet our customers' known preferences, including with respect to reliability (see Chapter 4); and
- address new regulatory obligations.

Put simply, our ICT proposal will ensure that we:

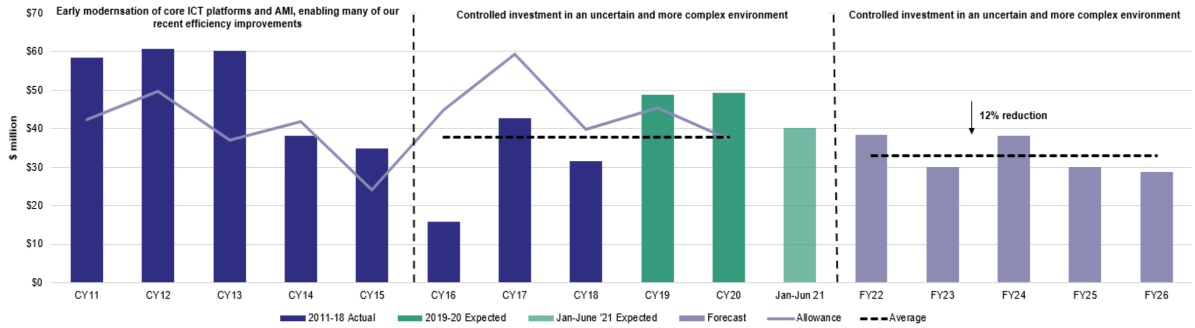
- communicate more effectively with our customers. Improved communication was one of the strongest themes from our customer research and it underpins a positive customer experience. We will achieve this by improving automation and collaboration within our workforce, and better communication tools to manage issues, including those associated with outages and voltage;
- continue to successfully monitor, support and manage the network system centrally and as part of a separate program;
- more accurately forecast DER uptake to better understand its impact and our ability to manage it as more customers connect DER resources to our network. Together with the work referred to in the preceding point, these initiatives will help our customers to fully leverage their investment in DER, thereby addressing another key concern for customers;
- bring disparate information sources together to develop an integrated and easily accessible source of reliable information across the company, enabling more effective business decision making, and ultimately facilitating better outcomes for customers; and
- meet new regulatory requirements that are applicable to us (as a DNSP).

For the 2022-26 regulatory period, we are proposing ICT investment of $165.4 million ($2021) – see the figure below. This is 12% lower than the expected spend in the current regulatory period.[79]

78 AMS 20-50 Steady State Voltage Compliance, AMS – Electricity Distribution Network.

79 Underspend in the early years of the current regulatory period has numerous sources, not least the decision to re-prioritise resources to meet obligations from the Power of Choice reforms, which required compliance by December 2017.

Figure 9-31: ICT capex 2011-26 ($m, $2021)



Note 1: Smart technologies (such as meters and switches) provide detailed and timely information on the state and usage of our network. Our use of that information allows us to plan and operate our network efficiently. Historically, we allocated smart technology costs to metering services. However, for the 2022-26 regulatory period, we have reallocated some of these costs to Standard Control Services, recognising their importance to distribution services. This reallocation needs consideration when comparing historical and forecast ICT capex.

Note 2: Jan to June 2021 is presented on an annualised basis.

In developing our ICT proposal we engaged external consultants and technology experts to provide industry benchmarks and budget estimates, ensuring our forecasts are prudent and efficient, and in line with industry best practice.[80]

9.12.2 Key drivers

As the energy sector is going through unprecedented change, we are continuously looking for ways to maintain services while also meeting customers' evolving needs. For example, the increasing uptake in, and advancement of, renewable generation technologies is changing the operational environment, impacts our relationship with customers and stakeholders, and is driving the way we plan and invest in ICT systems and capabilities.

Our Technology Strategy puts customer outcomes at the centre of our investment plans by prioritising the delivery of what customers are telling us they want and leveraging technology and opportunities to reduce our ongoing costs wherever possible. In summary, the factors we consider when developing our ICT expenditure forecasts are:

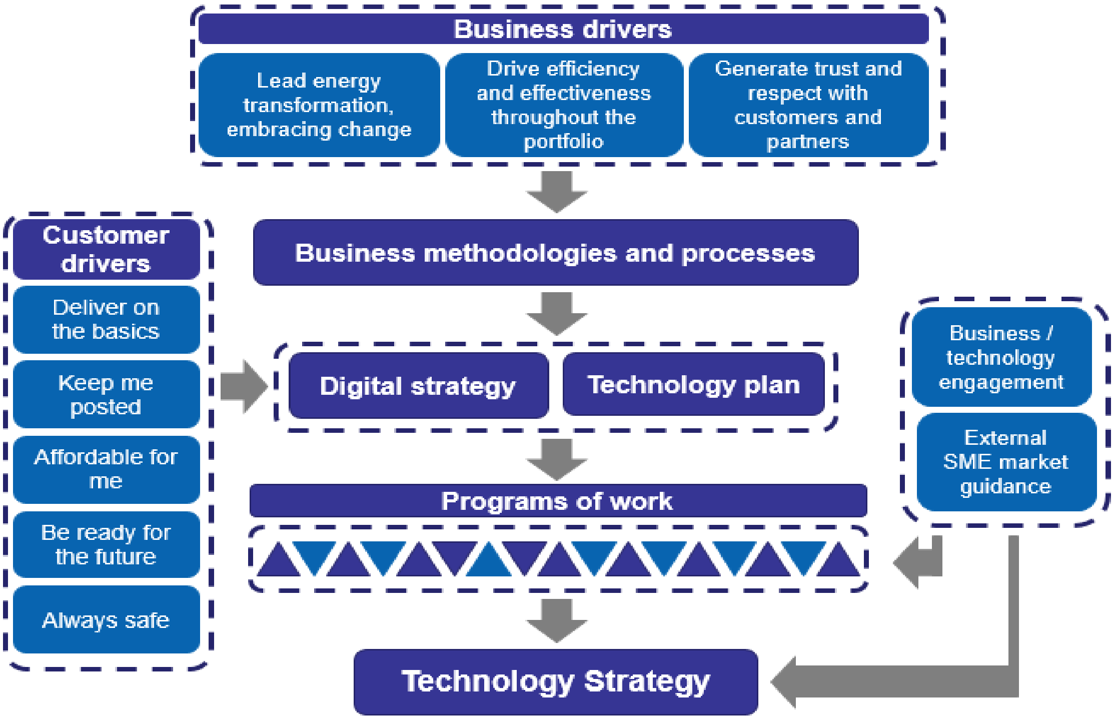
- Customer expectations: see discussion in section 9.4.
- Industry and Technology: Technology is fundamental to the operation of electricity networks and we are seeking to leverage digital technologies to maintain our operational efficiency and effectiveness in an increasingly complex environment. This includes leveraging the benefits of smart devices, automation, data and analytics, cloud computing, convergence of information and operational technology, and productivity tools for field and office workers.
- Cyber security: Responding to the increasing number and severity of cyber threats to ensure we maintain a safe and secure network and working environment, and to protect customers' privacy.
- Compliance: ICT enables us to comply with applicable regulations and requirements in a timely and efficient manner.
- Internal drivers: ICT has a key role in supporting enhanced decision making by providing improved analytics, reporting and data management; optimising costs by providing tools to

80 Our Technology Strategy (Appendix 9C) contains an extract from a Deloitte Consulting letter that outlines its role in helping us develop our ICT capex proposal and its satisfaction that each of our proposed ICT programs is required to enable the delivery of distribution services.

manage assets across their lifecycle; and providing greater integration and automation of processes and systems across the enterprise.

How these drivers (and our business drivers) have helped shape our Technology Strategy and proposed work program is summarised in the figure below.

Figure 9-32: Developing our Technology Strategy and work program



9.12.3 Projects and programs of work

Our proposed projects and programs of work for the 2022-26 regulatory period reflects our Technology Strategy. Specifically, our proposed work programs will help us maintain services, meet new regulatory obligations while also meeting customers' known preferences, including:

- maintaining current reliability levels (in an increasingly complex and challenging environment);
- a better customer experience, including more tailored customer service provided by enhanced customer information systems;
- more timely and accurate information about outages; and
- a strong desire to leverage investment in DER.

To ensure we can deliver these goals we have:

- considered customer needs, wants and expectations and how these are expected to evolve during the 2022-26 regulatory period, as revealed through feedback directly from the Customer Forum and through the customer engagement and research that we and the Customer Forum have undertaken;
- held discussions with business and technology architects, and (internal) business delivery leads to develop the scope, key objectives, and drivers of our ICT proposal;
- considered different options to achieve the objectives of each ICT program and analysed the relative costs, benefits and risks of each, paying specific attention to those projects that the AER may categorise as 'non-recurrent' expenditure; and

- undertaken a top-down review and internal challenge to ensure that our ICT proposal represents prudent and efficient expenditure for the 2022-26 regulatory period. These processes resulted in significant reductions between the preliminary expenditure forecasts developed in May 2018 (approximately $236 million)[81] and the $165.4 million in expenditure we now propose for the 2022-26 regulatory period.[82]

In costing our programs of work we have used industry standard labour rates and applied consistent costing methodologies to the different programs.

Importantly, recognising that our proposed program of work will generate operating efficiencies, we have included a 1% productivity saving in our opex proposals (see Chapter 10). This level of saving is only possible by carrying out recurrent and non-recurrent ICT expenditure simultaneously and heightens the efficiency of our proposed ICT expenditure.

Our ICT proposal involves 11 programs which are summarised in the table below.[83] However, detailed information is contained in ICT program briefs that accompany this proposal.

Table 9-13: ICT forecast capex ($m real, 2021)

Outcome	Program	Description	Proposed expenditure
Managing risk of not meeting expected demand for standard control services by renewing assets within vendor support windows	Technology Asset Management (TAM) - infrastructure	This program will: • maintain IT systems so that they remain up-to-date, robust, scalable, and continue to meet service obligations of business and regulatory requirements; and • help optimise data centre infrastructure assets, including platform, hardware and licenses.	28.1
	Technology Asset Management - applications	As we have around 200 applications that require periodic patching and enhancements to align with our Asset Management Policy, this program ensures ongoing risk mitigation, vendor support, security patches and bug fixes, limits downtime, ensures operating effectiveness and underpins the reliability of critical operations.	7.8
	Technology Asset Management - corporate communications networks	This program ensures the lifecycle management of corporate communications including technology networking devices (i.e. Wi-Fi, routers), internet services provision and gateways, as well as data centre interconnectivity, covering both systems and assets.	12.6
	Corporate enablement	This program will provide reliable service to customers by ensuring ongoing supportability	11.0

81 As demonstrated by the Customer Forum presentation entitled "2021-25 EDPR Revenue Update" located here.

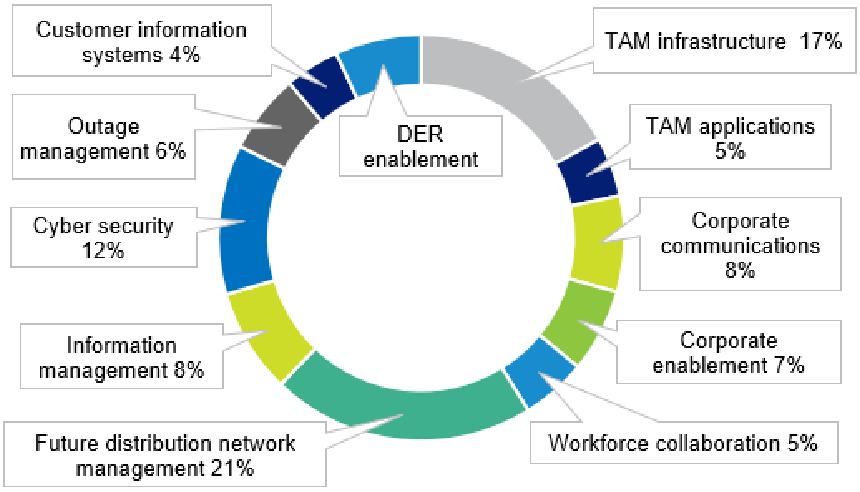
82 Section 2.2 of the Technology Strategy provides further information on the approach we took to develop our forecasts.

83 There are two additional ICT programs that are captured within our metering capex category – the 5 minute settlement program and the metering lifecycle program. Program briefs for both these programs accompany this proposal.

Outcome	Program	Description	Proposed expenditure
		and sustainability of core business systems (Finance, HR and Supplier Management. Consistent with the business shift to cloud-based solutions where prudent, core business functions such as HR and Payroll systems will move to the cloud, where the ERP solution will commence the pre-work required to prepare for migrating to the cloud post the end of the next regulatory period.	
Maintain performance and service levels where operating environment is more complex and challenging than in the past	Workforce collaboration	This program looks to allow access to information wherever staff are, including those in the field. It will also facilitate collaboration through knowledge capture and transfer, and improved accuracy of planning, budgeting and forecasting.	8.6
	Future distribution network management	This program ensures the continued safe operation of network management assets through a refresh of systems to ensure a supported, risk mitigated platform. Additionally, it looks to ensure appropriate systems and capabilities are in place to manage new the growth in distributed generation, residential batteries and Electric Vehicles.	34.7
	Information management	This program will allow us to continue to analyse network performance in an increasingly complex environment. It will be supported by advanced automation on near real time data, underpinning better decision making, more efficient operations and continued levels of high reliability.	13.8
Meet new regulatory obligations	Cyber security	Investment in cyber security is required to meet current and emerging regulations and laws. This program will protect our organisational assets, including information, applications, systems, networks and end user devices from internal and external cyber security threats. It will also ensure compliance with regulatory requirements.	19.8
Address the priorities expressed by our customers	Outage management	This program minimises the impact of planned outages on customers, by using advanced analytics and automation across the outage. It will also allow us to provide more accurate information to customers, including about outage restoration times, and will provide field crews with live data to optimise their effectiveness.	10.4

Outcome	Program	Description	Proposed expenditure
	Customer information systems	This program will improve the interaction we have with our customers. It involves implementing a CIM, which will allow us to provide appropriate advice to assist all our customers, including those who are connected with DER. In addition, it will also allow us to provide more personalised and tailored customer service.	7.2
	DER enablement	This program will more accurately forecast DER uptake and better understand the impact of DER on the network and existing connected customers. This will allow more accurate monitoring and understanding of the constraints arising from network and DER operations, ultimately increasing the network's ability to manage DER. This responds directly to customer feedback that they expect to be able to fully leverage their investments in DER. This program is heavily dependent on both the: • Future distribution network management program; and • Information management program.	11.4
Total			**165.4**

Figure 9-33: ICT forecast capex ($m real, 2021) (%)



As highlighted above, we have considered customer needs, wants and expectations when developing our ICT proposal. While all our proposed programs will help us maintain our performance and service levels, and our regulatory obligations, some projects will generate outcomes that may be more tangible for our customers. Programs where this is the case (where customer outcomes may be more tangible) include Outage Management, Customer Information Management and DER enablement, each of which we discuss briefly below.

We also note that, in the future, the distribution network will rely increasingly on smart meter data and supporting systems to sustain our current cost and service performance. While the need to leverage our systems and data is driven partly by the projected growth in DER and solar capacity, it is important to recognise the joint reliance of both the standard control and metering services on smart metering data and systems. How these costs are allocated is therefore important and the basis of our allocation is explained in Appendix 9E. Further information on Metering Services is at Chapter 19.

Outage Management

In addition to reduction in planned outages through improved asset management and outage planning, we expect to see greater customer satisfaction due to improved asset, network and service reliability and more accurate notifications and updates about the progress of work. For example, some of the benefits of this include:

- improved safety for both Life Support and Sensitive customers through improved notifications;
- significantly reducing the number of cancelled and rerouted jobs;
- performing more detailed scenario analysis as network performance is better known and tracked, thereby reducing the risk of failure of assets and therefore power cuts; and
- increasing our oversight and monitoring of asset performance, thereby giving us the ability to maintain assets based on real time information. More real time information means more expedient identification of and responses to challenges.

Customer Information Systems

We know from our customer engagement processes that all customers desire more personalised and tailored customer service, including with respect to outage information. For those connected with DER, we also know that they expect to be able to access advice that will help them maximise their generation. This program will contribute to meeting these goals. Expected customer benefits from this program include:

- more effective interaction, including personalised messaging, as we improve our understanding of our customers and their consumption profiles; and
- improved customer notification that will:
  - allow customers to benefit through selling excess solar and battery capacity, and
  - provide customers price signals and rebates encouraging them to use power or manage their DER exports.

DER enablement

As we noted above and elsewhere in this chapter, we know that customers expect to be able to leverage their investments in DER. Our DER enablement program will deliver a new technology platform (DENOP), see earlier discussion, and help customers to leverage their investments in DER. Expected customer benefits from this program include:

- reduced cost for participants, including a more streamlined application process with fewer rejected connection applications; and
- a reduced risk of damage to customer equipment caused by thermal overload resulting from poorly integrated or visible DER and, connected to that, improved voltage compliance across the network.

Further information on the customer (and network) benefits of each ICT program is available in the Technology Strategy (Appendix 9C) and the ICT Program Briefs which have been provided as part of this proposal.

9.12.3.1 Consideration of cloud based options

Recognising that the cost, performance and availability of externally hosted technology services – both infrastructure and applications – "in the cloud" has improved substantially over the last five years, we carefully considered the viability of cloud-based options when developing our ICT proposal. This involved:

- a high-level analysis of how we could transition our core systems infrastructure to the cloud; and
- consideration of the costs and risks of maintaining our current on-premises technology assets relative to a cloud-based option.

Our analysis concluded that we should not retire or replace the majority of our existing infrastructure and data stores with cloud-based solutions at this time. For us, as many of our core applications (in particular SAP) are relatively new, the lowest cost option is to transition to cloud based solutions in the medium rather than short term. However, we recognise that the cost/risk/benefit equation may be different for other networks.

Notwithstanding our general approach, some applications that support our business will need updating if we are to continue to have vendor support. In a few cases, this will mean moving to a cloud-based subscription services in the 2022-26 regulatory period. Where this is the case, we have captured the applicable costs in our proposal.

Moving applications into the cloud replaces capex with a new category of opex over the life of the technology service, creating a step change. After a detailed review of affected applications, we have identified the need for $4.4 million ($2021) per annum of additional opex for cloud hosting. We have agreed with the Customer Forum that we will only seek an opex step change of $0.5 million per annum as a step increase in our opex forecasts. We are committed to absorbing the remainder of the increases as an additional productivity measure. Unfortunately, as the hardware on which these applications run is shared with other services that are not transitioning (and which we will continue to need), it would not be prudent nor efficient for us to decommission that hardware during the 2022-26 regulatory period. This reduces our ability to realise capex savings in the short-term.

However, as the cost and performance of cloud-based services improve, we expect to be able to take increasing advantage of the opportunities presented and will increasingly move away from on-premises solutions. This should provide increasing opportunities to retire on-premises ICT infrastructure and avoid associated legacy costs.[84]

9.12.4 Benchmarking and validation

To obtain insight into the key ICT needs, trends and strategic direction of the business, all relevant areas of the business were engaged in preparing our ICT forecasts. We also used external consultants, including Deloitte Consulting and technology experts, to provide industry benchmarks and budget estimates to validate the efficiency of our proposed technology expenditure.[85] Our internal and external experts have also contributed to the development of our Technology Strategy.

Our approach to ICT gives us assurance that our forecasts are prudent and efficient and are in line with industry best practice.

[84] The complete transition to the cloud may take several years and cover several regulatory periods.

[85] The findings from Deloitte Consulting's independent review of our approach are outlined in Appendix 9C.

We also note that in late November 2019 the AER issued guidance on its approach to assessing non-network ICT capital expenditure.[86] We trust that the limited time available to us to fully consider this guidance material (recognising the governance processes that we must adhere to when preparing proposals such as this) will be reflected in the AER's assessment of our proposal. However, and more importantly, we remain unconvinced of the merits of the AER's approach to assessing non-network ICT capex and consider that both recurrent and non-recurrent ICT expenditure is required to achieve the productivity (1%) that we are proposing. We also note that:

- the indirect benefits that non-recurrent ICT investment can generate, including better business and/or customer outcomes, can be difficult to quantify;
- the benefits of ICT programs do not instantaneously appear but can take time to be revealed; and
- additional compliance costs are likely as a result of the AER's new approach.

Our concerns with the AER's new approach notwithstanding, provided as part of the supporting documents forming part of this proposal is information on how our non-recurrent ICT projects can be allocated to the sub-categories requested by the AER and a selection of ICT post implementation reports.

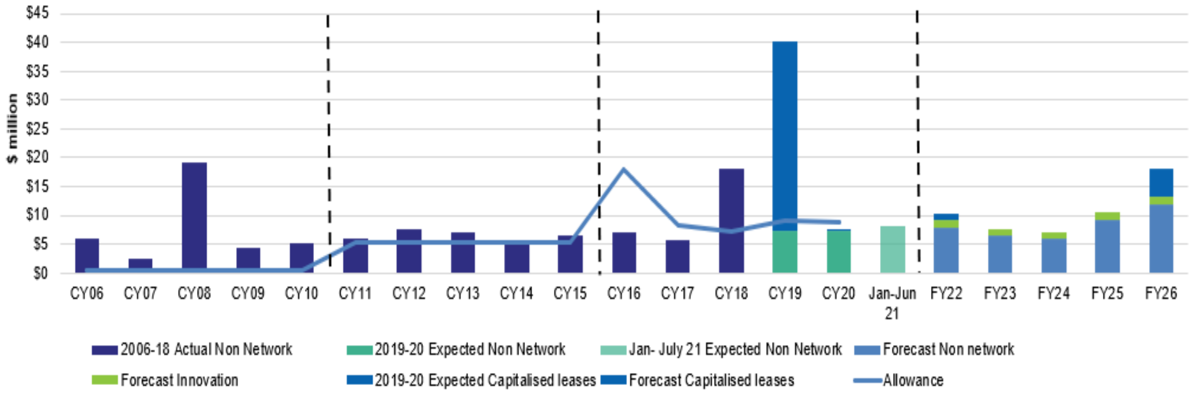
9.13 Other capex

9.13.1 Overview

The 'Other' capex category includes capex on motor vehicles, buildings, tools and test equipment. We are forecasting an allowance of $41.2 million ($2021) for the 2022-26 regulatory period for this aspect of Other capex. This is 9.5% lower than our expected expenditure in the current regulatory period, notwithstanding the expected purchase of numerous motor vehicles at the end of the next regulatory period.

The figure below shows our historical and forecast capex for the different elements of Other capex.

Figure 9-34: Other capex 2006 to 2026 ($m, $2021)



Note: Jan to June 2021 is presented on an annualised basis.

Other capex also captures capital leases. As explained later in this section, this is due to an accounting change relating to the treatment of leases. This has given rise to a non-recurrent capitalised lease cost of approximately $33 million in 2019 (and significantly smaller amounts in 2020). However, for the 2022-26 regulatory period, a significantly lower amount of capitalised lease

86 AER, Non-network ICT capex assessment approach, November 2019.

expenditure is expected ($6.2 million). These differences reflect the 'lumpy' nature of lease expenditure when treated as a capital cost.

We are also proposing around $6.4 million ($2021) of capex to undertake innovation projects during the 2022-26 regulatory period (see Chapter 11).

9.13.2 Key drivers

The expenditure drivers for the 'Other' capex category vary for each of the sub-categories, being vehicles, property and tools. In summary, the principal drivers are:

- ensuring the safety and well-being of our staff and contactors by providing depots, vehicles and tools that facilitates a safe working environment at all times;
- minimising total life cycle costs, including optimising the size and age of the vehicle fleet;
- ensuring that assets are managed in accordance with the relevant asset strategies; and
- achieving compliance with our statutory obligations.

9.13.3 Projects and programs of work

The table and figure below summarise the principal 'Other' capex projects and programs for the 2022-26 regulatory period, including the proposed expenditure over the forecast period and the percentage each project/program contributes to this expenditure category.

Table 9-14: Other – vehicles, property and tools projects and programs for 2022-26, direct capex ($m, 2021) and %

Project/Program	Total $M	% of Total
Property - capitalised leases	6.2	11%
Depot and station upgrades	13.8	26%
Vehicles	19.5	36%
Other	8.0	15%
Innovation	6.4	12%
Total	**53.8**	**100%**

Further detail on our principal projects and programs for the 'Other' capex category is below.

9.13.3.1 Property leases

From 1 April 2019, we are required to capitalise leases in accordance with changes to Australian Accounting Standards AASB16. The new accounting standard requires leases to be treated as an asset, under which the lessee has the right to use the asset and an obligation to make lease payments over the lease term.[87] Consequently, we have capitalised the remaining value of our property leases under standard control services by calculating the present value of the future lease payments in accordance with the accounting standard.

[87] For more information see Appendix 9E.

The change in the accounting treatment of leases results in an apparent increase in 'Other' capex. However, it will not lead to an overall increase in our revenue requirement as there is a corresponding decrease in opex. Accordingly, we have reduced our opex allowance to reflect the new accounting treatment of leases.

9.13.3.2 Depot and station upgrades

Forecast investment in upgrading depots and stations is consistent with recent historical levels of expenditure.

9.13.3.3 Vehicles

Our proposed vehicle fleet capital expenditure is in line with recent historical levels of expenditure and reflects the investment required to minimise the total life cycle cost of providing a safe, fit-for-purpose fleet. While we expect the composition of the fleet to remain broadly similar, there are numerous vehicle leases that expire towards the end of the next regulatory period, underpinning the expected increase seen in those years.

9.13.3.4 Benchmarking and validation

On a like-for-like basis (i.e. excluding capitalised leases and proposed innovation expenditure), our proposed 'Other capex' is largely in line with our historical spend.

9.14 Deliverability

Deliverability refers to the ability of the business to deliver the proposed program of work.

We have a demonstrated ability in delivering large and complex programs. For example, in the current regulatory period, we successfully delivered significant investment, including major safety programs (REFCL).

In the 2022-26 regulatory period, we are expecting to reduce our capex materially below the current regulatory period spend. However, within this relatively low level of (prudent and efficient) expenditure there is a step up in DER/voltage management programs that is offset by a decline in other programs, including REFCL.

Our proposed model of delivery is unchanged from our current approach and we will continue to use a hybrid operating model to deliver the works program that includes a mix of internal and external resources. External resources include fully outsourced teams in regional locations, Capital Panels established to provide top-up resources for minor works, and Major Capital Panels for delivery of major works.

This model improves efficiency by providing a mechanism to ensure internal resources are fully utilised, and that we resource peaks of work by engaging additional external resources. We select external service providers using a competitive process, ensuring efficient costs and the provision of quality services.

We will also continue to manage the uncertainty about the need for or timing of projects through the judicial use of external resources.

In addition, we will continue to see the benefits from several of our more recent initiatives that improve the delivery of our works program, including:

- Selection of Design and Installation Service Providers to a panel of service providers;
- Project PUMA, involving selection of a single supplier under a long-term contract to deliver works in the Central region; and
- Works integration to bundle works by distribution feeder.

We have also made improvements to our enterprise business process that we expect will improve our deliverability by facilitating better change management, enhanced governance and centralised planning and scheduling.

While we are not expecting any deliverability challenges from a volume perspective, some technical challenges remain. However, given the volume and nature of work, we do not expect to encounter significant challenges in delivering our proposed work program.

9.15 Why our capex forecasts satisfy the Rules requirements

The Rules require the AER to assess the prudency and efficiency of our capital expenditure, having regard to ‘capital expenditure factors’. These factors include:

- the AER’s most recent annual benchmarking reports;
- the actual and expected capital expenditure in previous regulatory periods;
- the extent to which the forecasts address the concerns of electricity consumers;
- the relative prices of operating and capital inputs;
- the substitution possibilities between operating and capital expenditure;
- whether the forecast is consistent with the applicable incentive schemes;
- whether the forecast reflects arrangements that are not on arm’s length terms;
- whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project;
- the extent we have considered, and made provision for, efficient and prudent non-network options; and
- any relevant final project assessment report, as required by the regulatory investment test.

As the AER is required to consider these factors in determining whether it is satisfied that the forecasts reasonably reflect the capital expenditure criteria, we have considered all those factors in developing our forecasts.[88] In particular, we note:

- The AER’s most recent benchmarking report highlights that we are the most improved performer under its preferred total factor productivity measure.[89] While we accept that we must continue to improve our relative performance, the improvements we have already achieved are positive. Moreover, our improvement reflects the significant efficiency savings and business process improvements we have realised in the current regulatory period, which underpin our expenditure forecasts for the next regulatory period. Our gross capex proposal reflects this, with it being around 14% lower than our most recent historical expenditure.
- Our approach to customer engagement in the lead up to and during the preparation of this proposal is a substantial improvement on our previous engagement processes. For example, as explained in Part I of this proposal, the establishment of the Customer Forum and the intensive scrutiny it applied to our proposal (including our earlier Draft Regulatory Proposal) has produced customer-centric plans that reflect the lowest sustainable cost of providing distribution services. We are therefore confident that our forecasts address the concerns of electricity consumers.

88 National Electricity Rules, clause s 6.5.7 (a) and (c).

89 AER, Annual Benchmarking Report, Distribution Network Service Providers, November 2018, p. iii.

- We routinely consider operating and capital input prices and substitution possibilities when developing our business cases. Similarly, we routinely consider non-network options in our project evaluations, and adopt them where it is cost effective to do so.
- Our capex proposal focuses on maintaining reliability, which is consistent with the design of the AER's incentive schemes.
- Related party arrangements do not affect our forecasts.
- There are no final project assessment reports in relation to our capex forecasts.

In addition, as explained earlier, our forecasts for each expenditure category reflect our customers' preferences as well as a robust, analytical approach to asset management. Our approach also has a clear focus on delivering safe, reliable and affordable distribution services. Taken together, we are confident that our capex forecasts comply with the Rules requirements and consider that they should be accepted by the AER.

9.16 Supporting documentation

In addition to the PTRM and RIN templates submitted with this proposal, we have provided the following key documents in support of our capex proposal:

- Appendix 9A – Project Cost Estimating Methodology;
- Appendix 9B – Unit rates;
- Appendix 9C – Technology Strategy;
- Appendix 9D – Allocation – AMI ICT and Distribution;
- Appendix 9E – Lease Treatment;
- Capex Model; and
- Connections Capex Forecast Model.

A significant number of other supporting documents, including planning reports and ICT program briefs also form part of this proposal.

10 Operating expenditure forecast

10.1 Key points

- We are listening to customers and have agreed our forecast opex with the Customer Forum. We have listened to customers and worked with the Customer Forum to develop a prudent and efficient operating expenditure (opex) proposal that balances our obligation to provide safe and reliable electricity supply with the affordability concerns of customers.
- We have reduced our operating cost base. Over the last three years we have undertaken a ground-up cost efficiency program which is delivering lasting cost savings for our customers. A combination of smarter work practices, new workforce contracts and a continual focus on cost management has delivered these savings. This is allowing us to control costs, even while our customer base and obligations are growing.
- We have agreed with the Customer Forum to double the ongoing cost savings sought by the AER to over 1% per annum. This represents a substantial outperformance of the AER's productivity setting of 0.5% per annum in the 2022-26 regulatory period. We are delivering these savings by absorbing (self-funding) $21 million ($2021) of costs associated with new business obligations and operational needs. Costs we are proposing to absorb include:
  - The forthcoming increase in the superannuation guarantee (from 1 July 2021). Absorbing this cost is forecast to save customers $6.5 million ($2021);
  - Increases in our bushfire insurance. Absorbing this cost is forecast to save customers $7 million ($2021);
  - A demand management solution at Cranbourne Terminal Station. Absorbing this cost is forecast to save customers $1.5 million ($2021);
  - Compliance with new *Environmental Protection Act* obligations. Absorbing this cost forecast to save customers $1 million ($2021); and
  - Most of the costs associated with transitioning to cloud-based IT systems. Absorbing these costs is forecast to save customers over $5 million ($2021).
- Some increase in opex is required to address new and more substantial obligations, our growing customer base and more sophisticated use of data. Substantial new cost pressures and regulatory obligations have been introduced by governments and regulators that will increase costs in the next regulatory period. These relate to market settlement, cyber security and bushfire safety. Meeting these obligations at an efficient cost will add $14.3 million ($2021) to our opex proposal over the 2022-26 regulatory period.
- Our increasingly sophisticated use of our smart meter fleet is allowing us to run the network more efficiently. To reflect the increased usage of our smart metering systems for distribution purposes, we have allocated a greater share of the smart meter ICT costs to the distribution business. This change has added $30 million ($2021) to our distribution opex but reduces our metering costs by the same amount (and hence metering charges to customers).
- Even with new obligations and growth, our total opex forecast is 5% below our current regulatory period allowance. Our cost reductions, and the collaboration with our customers, results in a forecast of total opex of $1,222 million ($2021) over the 2022-26 regulatory period.[1] This is 5% lower than our opex allowance in the current (2016-20) regulatory period.

[1] This forecast opex does not include debt raising costs, consistent with the basis we negotiated with the Customer Forum.

- Our proposed opex allowance will reduce by 12% between 31 December 2020 and 1 July 2021. This reduction will deliver immediate benefits to our customers by reducing the opex allowance by $47 per customer.
- The Customer Forum agrees our opex forecast represents value for money. The Customer Forum considers that in the context of the proposed minimum average customer price reduction of $110 per annum,[2] taken together with other expenditure savings, the opex proposal appears to represent overall value for money.

10.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 10.3 summarises our opex forecasts;
- Section 10.4 explains our approach to forecasting our opex;
- Section 10.5 provides information on our customers' preferences and feedback;
- Section 10.6 outlines our negotiations with the Customer Forum and explains how these have been used in preparing our opex forecasts;
- Section 10.7 provides key inputs and assumptions;
- Section 10.8 describes the base year expenditure used in developing our forecasts;
- Section 10.9 describes the step changes we have included in our expenditure forecasts, as well as the step changes we propose to absorb;
- Section 10.10 presents information on those elements of our opex forecast that have been subject to a bottom-up forecast;
- Section 10.11 explains how our opex forecasts have taken the trends in input costs, output growth and productivity into account;
- Section 10.12 explains compliance with section 71YA;
- Section 10.13 explains why our opex forecasts satisfy the requirements of the Rules; and
- Section 10.14 lists the key supporting documents for this chapter.

10.3 Summary of operating expenditure forecasts

This chapter sets out our proposed standard control services (SCS) operating and maintenance expenditure forecast for the 2022-26 regulatory period. This expenditure has been allocated to SCS in accordance with our approved cost allocation methodology.

Our proposed expenditure looks to ensure we continue to operate and maintain the network to a standard that ensures customers have access to a safe and reliable electricity supply, as well as comply with numerous externally driven regulatory obligations and requirements. The application of the base-step-trend approach to our efficient base year opex produces a total opex forecast that is prudent and efficient, and which is required to achieve the operating expenditure objectives set out in the NER.

Our opex allowance will reduce by 12% between 31 December 2020 and 1 July 2021. Considering growth in customer numbers, this will translate into a $47 reduction in opex per customer. This will deliver real cost savings to all our customers in the next regulatory period and is only possible as a result of the significant opex savings we have achieved in recent years by pursuing a strong company-wide cost reduction program. A program that now also allows us to absorb significant new cost pressures.

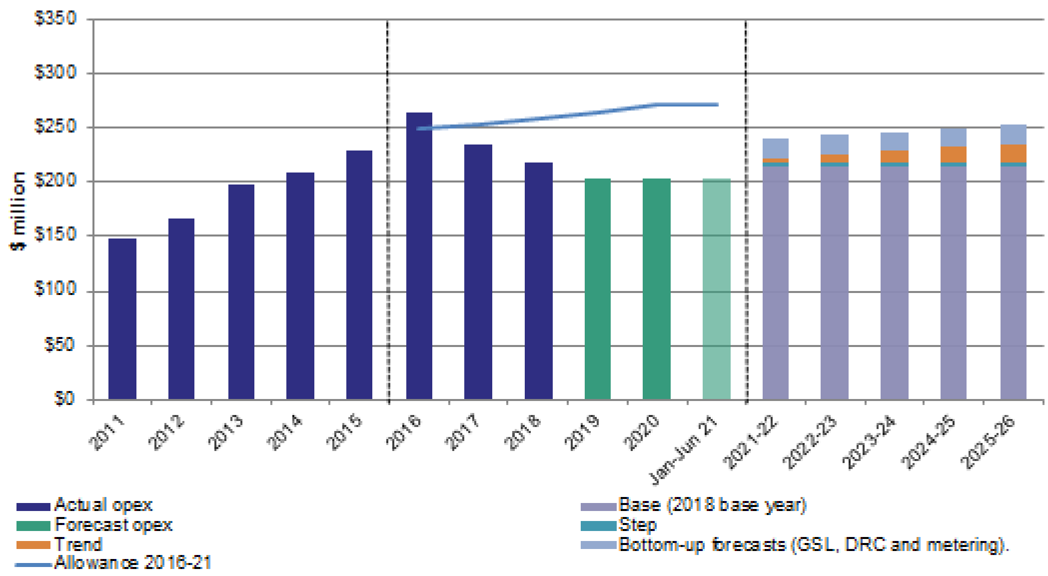
2 This reduction of $110 per annum is achieved across the entire regulatory proposal.

With customers demanding a strong focus on affordability, our proposed opex minimises costs while ensuring we can maintain the reliability and safety of our network services. It will also allow us to accommodate the growing numbers of customers on our network.

Following extensive negotiation with the Customer Forum and other stakeholders, we are forecasting total opex of $1,222 million ($2021) over the 2022-26 (FY) regulatory period.[3] This is, on average, 5% lower than our opex allowance in over the 2016-2020 regulatory period.

Figure 10-1 below shows our recent actual opex alongside our forecast opex for the 2022-26 regulatory period.

Figure 10-1: Actual and forecast operating expenditure $m real 2021



Source: AusNet Services

Our proposed total opex is set out in Table 10-1 below.

[3] This forecast opex does not include debt raising costs, consistent with the basis we negotiated with the Customer Forum.

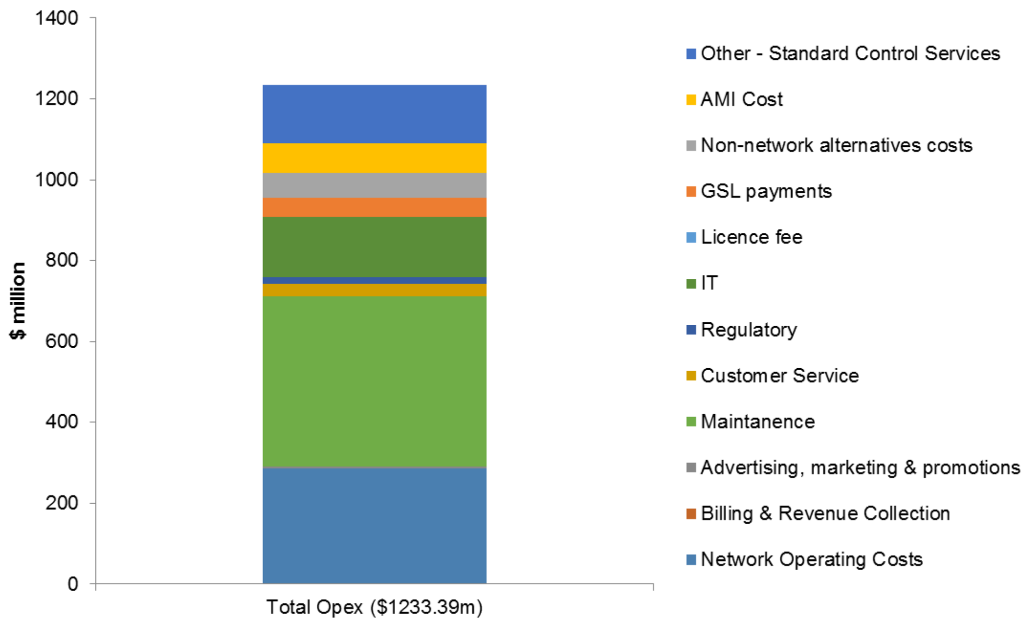
Table 10-1: Forecast opex ($m real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Base opex	215.4	215.4	215.4	215.4	215.4	1,076.8
Step changes	3.4	3.5	3.2	3.3	3.4	16.9
Trend (output, labour and productivity)	3.4	6.7	10.5	13.7	16.2	50.5
Bottom-up forecasts (Metering reallocation, Guaranteed Service Level payments, debt raising costs and innovation expenditure)	17.6	17.7	17.8	18.0	18.1	89.1
Total opex allowance	**239.8**	**243.3**	**246.9**	**250.4**	**253.0**	**1,233.4**
Total opex allowance (excluding debt raising costs)	**237.4**	**241.0**	**244.5**	**248.0**	**250.6**	**1,221.6**

Source: AusNet Services.

Opex forecasts broken down by well accepted expenditure categories are set-out in the figure below and our RIN template. As we have used a high level base, step and trend forecasting approach, the category forecasts are indicative of the expenditure we expect to incur in each category, but does not represent a bottom-up build for each category.[4]

Figure 10-2: Forecast opex by category ($m real 2021)



4 Forecasts in these categories in a numerical form are contained in RIN template 3.2.1.

10.4 Forecasting approach

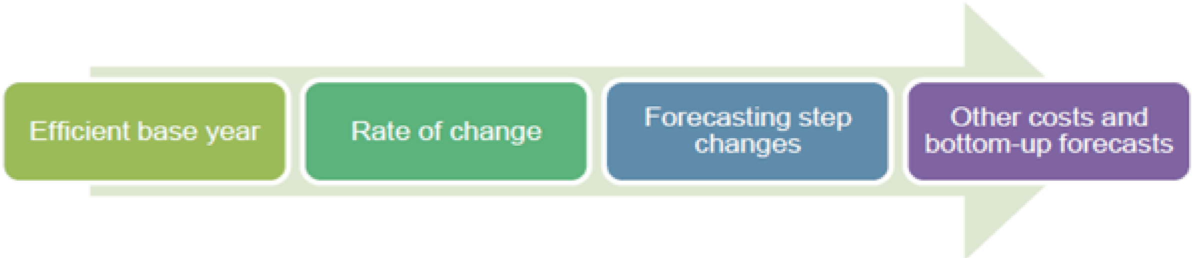
We have developed our opex forecasts using the base, step and trend methodology consistent with the AER's Expenditure Forecast Assessment Guidelines. To ensure this approach produces a prudent and efficient forecast an efficient level of base year opex is required.

For the reasons outlined in section 10.8.2 below, we consider that our base year opex is efficient. Accordingly, we have used a base-step-trend approach (using revealed costs) to forecast our opex requirements over the forthcoming regulatory period.

As shown in the figure below, the base, step and trend approach to forecasting opex works as follows:

- A base year of opex is selected that is representative of efficient costs. Adjustments are made to remove non-recurrent costs or to account for changes in accounting treatments.
- A rate of change is applied to the adjusted base year to account for forecast changes in input prices, network growth and productivity, which are drivers of opex trends.
- Proposed step changes or costs forecast derived using a bottom-up methodology are added. Step changes generally reflect changes in regulatory obligations or an opex/capex trade-off.

Figure 10-3: Opex forecasting methodology



Importantly, all aspects of the opex forecast were within the scope of our negotiations with the Customer Forum. As such, our negotiations with the Customer Forum covered:

- the selection of the base year and necessary adjustments to expenditure in that year;
- all step changes; and
- trend parameters.

The negotiated outcome on each element is set out in section 10.6 below.

Further details of our opex forecasting approach are provided in our Expenditure Forecasting Methodology, which we submitted to the AER on 21 December 2018.

10.5 Customer preferences and feedback

We have completed significant customer research to support our proposal which has been complemented by the insights and feedback provided by our Customer Forum.

In our customer research, participants repeatedly noted that the price of electricity had risen significantly and was continuing to do so.[5] Many were concerned electricity was becoming increasingly unaffordable and that it was now hard to pay their bills.

We also received written submissions on the opex proposals contained in our Draft Proposal from:

- the Energy Users Association of Australia (EUAA); and
- the Consumer Challenge Panel (CCP).

[5] Quantum Market Research, *Attitudes and Perceptions Survey*, May 2018.

AER staff also issued a guidance note outlining the areas that the Customer Forum (and us) may wish to give further consideration.[6] This was a useful addition to the discussion, as it helped us refine our proposal as well as have more productive discussions with the Customer Forum.

The feedback provided by customers and stakeholders showed they clearly desired a greater focus on affordability and expected the business to find additional efficiencies. We also held Deep Dive Workshops on Opex on 11 February.[7]

Detailed feedback on the opex proposal included in our Draft Proposal is summarised in the table below.

Table 10-2: Feedback on the Draft Proposal

	Comment	Our response
Base opex	The EUAA did not support our opex proposal. Rather, it considered it was a good starting point for discussions around further reductions. It questioned whether our 2018 base year was efficient and wished to engage further with the AER on the overall efficiency of our opex forecast. The EUAA commented that: *The proposed reductions in opex and capex for the 2020-25 period are relatively small with the price reductions driven as much by falls in WACC than they are by actions actually taken by AusNet.*	We consider that our base year opex is efficient. Our opex has fallen in 2017 and 2018 and was a 3% positive contributor to our TFP in 2018. While our productivity did decline in 2018, this was due to a poor year of reliability. The AER's 2019 benchmarking report confirms that we are a reasonably efficient DNSP. Importantly, the AER has committed to reviewing bushfire risk as an operating environment factor that is not yet incorporated into the benchmarking analysis swell as considering DNSPs capitalisation policies. These issues mean that our relative efficiency is greater than that shown by the AER's benchmarking report. Since the EUAA's submission, we have also committed to absorbing additional costs within our existing base year allowance. We have also adopted the AER's final decision on opex productivity, which reduces our allowance by 0.5% per annum. Taken together, we are now proposing an annual productivity saving of over 1%.

6 AER, Staff guidance note 9 (available at: https://www.aer.gov.au/system/files/AER%20Ausnet%20Services%20trial%20-%20Guidance%20note%209%20-%20draft%20proposal%20and%20interim%20engagement%20report%20-%20March%202019.pdf – accessed 9 July 2019).

7 Deep Dive Workshop One – Summary Report, AusNet Services Electricity Distribution Price Review 2021 – 2025 10 April 2019.

	Comment	Our response
Base opex	The CCP stated that it would expect to see explicit reference to savings that have been made through the smart meter benefits.	Section 19.6 and 19.7 (Metering Chapter) outline benefits to customers from smart metering. We are now utilising these systems to carry out numerous distribution functions including, network planning, call centre operations, and outage management. Any cost savings from these activities would be captured by our base year expenditure but are not explicitly quantified.
Base opex	Energy Consumers Australia (ECA) suggests that we should use the latest data for its base year. At this stage, that would be 2019, which would be the latest full year of data available to the AER.	2018 audited data is the most recent full calendar year data that we available for our regulatory proposal. We are indifferent to the selection of the base year due to the interactions between the opex forecast and the EBSS.
Step changes	The CCP considered that further analysis of the individual step change proposals is warranted, particularly with respect to assumptions around the business drivers, and the timing and quantum of proposed expenditure.	The additional information contained in this regulatory proposal provides the information sought by the CCP.
Step changes	At the deep dive several stakeholders questioned whether we should absorb immaterial step changes within the overall opex allowance.	We have taken this feedback on board and are proposing to absorb numerous step changes. In total, we are proposing to absorb $21 million of costs.
Step change – REFCLs	The AER questioned the REFCL step change and stated that 'to justify the step change AusNet Services could explain why the higher opex requirement is necessary to meet the Victorian regulatory requirements and why it does not duplicate opex in the first two tranches.'	The expenditure necessary is for ongoing additional testing and maintenance required after the commissioning phase of the REFCL program. There was an error in our calculation of the REFCL step change that formed part of our draft proposal. We have adjusted our calculation, which reduces the amount of the step change.
Step change – IT Cloud	AER staff noted that under the proposed Customer Satisfaction Incentive Scheme (CSIS) we may be rewarded for investing in the cloud-based systems (Customer relationship management 'CRM' and Outage Management System	The CSIS targets 4 key interactions with customers: planned outages, unplanned outages, connections and complaints. These were identified as high priority interactions between customers and us. However, they do not cover the full breadth of interactions that customers

	Comment	Our response
	'OMS'). Thus, if this scheme is developed, it may be another avenue of funding for the step change to transition to cloud based software.	have with us. As the CRM will impact throughout our business, the CSIS would be insufficient to incentivise this program at this time.
Trend (output, labour and productivity)	The CCP stated that the Customer Forum should continue to engage with us about opex productivity improvements above the 0.5% AER specified minimum.	We accept the AER's final decision and have applied a 0.5% productivity adjustment. In addition, we have agreed to absorb additional opex increases. By doing so, we will bring our effective productivity adjustment to over 1% per annum.
Trend (output, labour and productivity)	The EUAA questioned how the proposal would be 'reasonable' given the Customer Forums support for 1.5% opex productivity.	See above comments.
Trend (output, labour and productivity)	The AER noted that our early commitment to adopt their productivity adjustment means that the AER will not need to revisit the productivity growth factor when assessing our regulatory proposal.	Agreed.
Metering reallocation,	The CCP questioned whether the reduction in metering charges was simply a result of the allocation of some costs to the SCS.	As set-out in Chapter 19, the reduction in metering charges has been achieved primarily through efficiency gains in metering operations. The revised allocation of system costs contributed $7 (real $2021) of the total reduction of $30 per customer.
Innovation Expenditure	AER staff indicated that they do not consider that the AER's opex forecast can include a general allowance for innovation unlinked to specific projects. Additionally, they indicated that the proposed step change for innovation might be recovered through other means, and if so, there would be no need to provide for these projects in the opex forecast.	We are presenting specific innovation projects supported by business cases and evidence of customer benefits assessed against criteria developed by the Customer Forum. We are also unaware of any clauses in the National Electricity Rules which would prohibit the approval of an allowance for innovation or another mechanism by which the proposed step change would be recovered.

Source: AusNet Services.

10.6 Opex negotiations with the Customer Forum

Following the publication of our Draft Proposal the Customer Forum pressed us strongly to deliver further reductions in our proposed opex forecast. While open to looking for further savings, we considered that any further savings should not compromise innovation or baseline investment in customer experience capability.

We therefore decided to absorb a significant number of additional costs that we will incur in the forecast period. This commitment to finding additional efficiency improvements over and above the AER productivity trend of 0.5% means we are proposing an effective productivity adjustment of over 1%. This means that as a result of our negotiations with the Customer Forum, we have agreed to absorb $21 million in additional costs that we expect to incur in the 2022-26 regulatory period.

We negotiated with the Customer Forum on each element of our forecast opex. The focus of the negotiation and the agreed outcomes are summarised below.

Table 10-3: Negotiation of 2022 to 2026 operating expenditure

Opex element	Negotiation issues	Agreed outcome
Base opex	Which year to use as the base year	The Customer Forum accepted 2018 as a base year, subject to AER confirmation that it regarded 2018 as "efficient" for the purposes of the EDPR process. This year has a lower level of opex compared to the previous two years due to cost reductions arising from a cost savings program we have been implementing for the last two years. This will deliver ongoing savings for customers.
Step changes		
Regulatory changes	REFCLs	The Customer Forum had earlier supported this step change, subject to AER validation of the technical and financial aspects. However, this is a complex technical and commercial issue and the uncertainty makes it impossible for Customer Forum to offer a final opinion at this time.
Regulatory changes	5 minute metering	The Customer Forum accepted our 5 minute metering proposal, subject to the AER being satisfied the revenue sought fairly covered the cost involved of this mandatory change.
Regulatory changes	Cyber security	The Customer Forum recognises the escalating risk in relation to the global cyber threat environment and considers a step change of some kind could be justified. Given the highly technical and sensitive nature of this issues, along with the uncertainty of the emerging regulatory requirements, we believe this issue should be resolved directly with the AER as part of the later stages of the EDPR process.
Cloud IT	Change in delivery approaches and	The Customer Forum agreed to a step change for a Cloud-based Customer Relationship Management (CRM) IT system (approximately $500,000 per

	Capex/Opex trade-offs.	annum), which will deliver outcomes valued by customers. The Customer Forum did not agree to an additional $1 million per annum of step changes for Cloud-based IT systems which are capex-opex trade-offs. We have agreed to absorb these costs within the overall opex allowance.
Bottom-up Forecasts		
GSL	Funding amount	We have agreed to the Customer Forum's request that we self-fund GSL payments for controllable contingencies such as missed appointments and connections failing to be done by the advised date
Debt raising costs	Benchmark approach	We have adopted the AER's benchmark approach.
Metering re-allocation	Amount	The Customer Forum agreed that metering systems are increasingly being used to provide standard control services and as such allocating a greater proposition of costs to standard control services is consistent with the use of these systems.
Innovation	Innovation expenditure	The Customer Forum agreed to opex investments in innovation (see Chapter 11).
Trend		
Price growth	Labour price	We have adopted the AER's approach. Labour costs and customer growth numbers appeared reasonable and will be subject to AER scrutiny once we lodge our formal submission.
Output growth	Growth measure	We have adopted the AER's approach. The Customer Forum was satisfied the trend factors submitted by us were a realistic reflection of expected working environment and would be acceptable to customers.
Productivity	How much productivity growth can be achieved over 2022 to 2026	We have applied a productivity adjustment of 0.5% and agreed to absorb an additional 0.5% per annum in cost pressures. This brings the total productivity adjustment above 1%. The Customer Forum considers that in the context of the proposed minimum average customer price reduction of $110 per annum, taken together with other expenditure savings, the opex proposal appears to represent overall value for money. As such, they accept the overall productivity savings proposed by us.

The Customer Forum has agreed in principle with our 2022 to 2026 opex forecast (shown in section 10.3), on the basis that the AER will thoroughly assess it.

10.7 Key inputs and material assumptions

Key inputs and material assumptions underpinning our opex forecast are:

- Base year expenditure and all adjustments have been sourced from our audited regulatory accounts.
- Output growth has been forecast using an average of the AER's four benchmarking models:
  - Customer numbers have been forecast in accordance with the methodology set-out in Chapter 7;
  - Circuit length has been forecast based on historical growth rates;
  - Ratcheted maximum demand was forecast using forecasts from AEMO; and
  - Energy throughput has been forecast in accordance with the methodology set-out in Chapter 7.

Price growth is based on a forecast of the Wage Price Index WPI consistent with the ABS series. We have averaged two consultants' reports for the final value consistent with previous approaches undertaken by the AER.

Step changes and bottom-up forecasts have been forecast on a bottom-up basis do derive the best forecast available of likely incurred costs. Material Assumptions about step changes and bottom-up are provided in attached models.[8]

Significant variations in the forecast operating expenditure from historical operating expenditure relate to:

- The allocation of additional AMI ICT costs to standard control services, explained in section 10.10.3 below.
- Removal of ESV Levy amounts from the opex forecast. We propose to recover these through the annual tariff process, explained in section 10.8.1 below.

10.8 Base year expenditure

To ensure the base, step and trend forecasting approach produces a prudent and efficient forecast, an efficient level of base year opex must be selected.

We have nominated the 2018 calendar year as the base year for forecasting opex as:

- 2018 is the most recent regulatory year for which audited regulatory accounts and other financial information is available. We achieved significant savings from our efficiency program in both 2017 and 2018, which is captured in our base year expenditure. Economic benchmarking and category analysis also demonstrate that we are efficient relative to our peers. The improving trend in efficiency we have achieved since 2016 also demonstrates that we have responded to the incentives under the regulatory regime and continue to seek further efficiency improvements over time.
- While we anticipate further reductions in opex in 2019, the operation of the EBSS ensures that our revenue is unaffected by the choice of base year. As we have used the base, step and trend forecasting approach, our opex forecast is consistent with the operation of the EBSS in the 2016-2020 regulatory period and its proposed operation in the 2022-26 regulatory period.

[8] ASD - Opex - Material Assumptions - Public.xlsx, ASD - 2021-26 Proposal Opex model - Final - Public.xlsm, ASD - WPI calculation - Public.xlsx, ASD - AEMO TCP Forecasts - Public.xlsx, ASD - Metering Reallocation calculation - Public.xlsx, ASD - REFCL CPA Tranche 1 - Total Cost Model - Public.xlsx, ASD - REFCL CPA Tranche 2 - Total Cost Model - Public.xlsx, ASD - REFCL CPA Tranche 3 - Total Cost Model - Public.xlsx, ASD - Merits Review Opex - Confidential.xlsx

- There were no unusual events or factors in 2018 that indicate it is not reflective of our normal operating environment.

Given the above, we consider that 2018 is suitable to use as the base year for our opex forecasts for the 2022-26 regulatory period.

10.8.1 Adjustments to base year

Notwithstanding identifying 2018 as an efficient base year for the 2022-26 regulatory period, we have made several adjustments to our actual 2018 expenditure (which was $205.4 million (nominal)) to ensure it is representative of efficient costs. Our adjustments removed:

- $6.6 million of GSL costs. These are forecast using a bottom-up approach to produce a category specific forecast.
- $0.23 million of Demand Management Innovation Allowance (DMIA) expenditure.
- $0.49 million for movements in provisions.
- $4.3 million of expenditure on building and motor vehicle leases, which will be capitalised from 1 July 2019 consistent with accounting standard AASB 16; and
- $2.3 million of expenditure on the ESV levy (proposed to be recovered through the annual tariff process as a direct pass-through instead).

In addition, to forecast the base year opex at the end of the 2016-20 regulatory period (31 December 2020), we applied the forecast trend from the 2016-20 regulatory period to derive opex in 2020.[9] These changes mean that we are proposing a base year opex of $215.4 million. The table below shows how we have derived this estimate.

Table 10-4: Derivation of base year opex

	Amount
Actual 2018 opex (nominal)	205.4
GSL costs	6.6
Movements in provisions	0.2
DMIA	0.5
Base year opex (nominal)	**198.3**
Escalation and trend to 2021	24.0
Lease Capitalisation and ESV Levy Adjustments ($2021)	-6.9
Estimated base year opex ($2021)	**215.4**

Source: AusNet Services.

Further information on each of our adjustments is outlined below.

[9] Consistent with the 'top-down' forecasting methodology adopted, we have not explicitly identified and quantified non-recurrent expenditure categories over the forthcoming regulatory period. However, it is assumed that non-recurrent expenditure will rise and fall across the forthcoming regulatory period such that non-recurrent opex is broadly consistent from year-to-year. Similarly, we have not identified any non-recurrent expenditure in the 2018 base year.

10.8.1.1 Category specific forecasts (GSLs and debt raising costs)

We propose category specific forecasts for two categories of our opex, which are the GSL scheme and the debt raising costs. We removed $6.6 million from the base year expenditure, reflecting actual expenditure in 2018. A bottom-up forecast of these costs is then included in our opex forecast. The bottom-up approach is consistent with the approach taken in the 2016-20 regulatory period as well as more recent AER revenue determinations. We consider that bottom-up forecasts remain the appropriate approach to forecasting these costs.

10.8.1.2 DMIA

Costs incurred under the DMIA ($0.23 million) have been removed from the base year opex as these are funded separately through that allowance.

10.8.1.3 Movement in provisions

We have removed movements in provisions of $0.49 million from the 2018 base year to ensure that the opex allowance reflects the underlying recurrent opex. This is consistent with the approach we took in the 2016-20 regulatory period.

10.8.1.4 Lease capitalisation

A revised accounting standard (AASB 16) applied from 1 April 2019. Under the revised accounting standard, operating leases became ‘Right to Use’ (capital) assets. As a result, leases must now be treated as capex rather than opex. The purpose of the accounting standard change is to ensure the comparability of a company’s profitability regardless of whether they choose to purchase or lease property, plant and equipment.

We plan to align the regulatory accounting treatment with the statutory accounting treatment. Applying the accounting treatment to our regulatory accounts will reduce our opex by $4.5 million per annum going forward. Correspondingly, there will be an increase in our capex and RAB. We have calculated the increased RAB in accordance with AASB 16.

We have removed the lease costs from our 2018 base year for the purpose of calculating our opex allowance. Correspondingly, we have adjusted the opex for the EBSS reward in 2018 to match.

10.8.1.5 ESV levy

Our price control formula contains an L Factor, which is an adjustment factor for the Victorian Essential Services Commission annual licence fees. We propose to treat the annual levy from Energy Safe Victoria (ESV) in the same manner rather than proposing a step change.

We consider an annual adjustment in the price control formula is a more appropriate approach to this adjustment as it ensures we can recover the actual amount incurred regardless of any revisions of these levies. We have no control over these levies and note that the ESV has recently announced significant increases in it – it will increase by 51% from $2.3 million in 2018 to $3.5 million in 2024.

Our proposed approach decreases our total opex allowance by $11.5 million. However, the costs of the levy increases will still be paid by our customers, through the L factor in the price control formula (see Chapter 18, section 5).

If our proposed approach is not accepted, the cost of the ESV levy should be added back into the base year and an additional step change in our opex proposal will be required.

10.8.2 Demonstrating the efficiency of our base year expenditure

During the current regulatory period, the transformation of Australia’s energy supply chain has accelerated, typified by the closure of the Hazelwood coal power station and massive increase in large scale renewables at one end and the significant uptake in DER technology at the other. Meanwhile community concerns about energy affordability have increased. In response, we refreshed our corporate strategy and embarked on a renewed five-year plan, 'Focus 2021'. A key objective of the strategy is to operate all three of our networks (electricity distribution, electricity transmission and gas distribution) in the top quartile of efficiency benchmarks. This both reduces costs for customers and frees up resources to be reinvested in meeting the challenges of this transformation.

Our transformation journey commenced with the roll out of an enterprise resource planning (ERP) solution in 2015. The efficiency program is ongoing and continues to transform the way we operate. The ERP system allows us to collect, store, manage and interpret data from many business activities in one database. This has provided better access to data within the organisation, resulting in improved asset management, works planning and scheduling. The improved data analysis allows us to identify and implement efficiency improvements that we could not previously identify. The ERP solution is recognised as a foundational element, which feeds into nearly all other cost reduction initiatives and allows us to drive greater business-wide efficiencies. The ERP's implementation has also enabled us to retire multiple legacy systems.

Following the ERP's implementation, we embarked on a series of outsourcing initiatives. The first involved an IT Outsourcing contract with a specialist IT service provider. Shortly thereafter, another outsourcing agreement was executed for business back office processing activities. Both outsourcing arrangements involved the substantial reduction of headcount and improved labour efficiencies. Leveraging the ERP system has been a key enabler of these changes.

Along with outsourcing arrangements, we have delivered considerable savings through our procurement function, streamlining of contracts, operating model changes and property rationalisation. The next phase of the program is focusing on digital solutions and system automation, implementation of more robust processes and data management, as well as end to end process optimisation. The initiatives will require further change and adaptive processes to implement and again will touch all corners of the organisation.

As a result of these significant cost reductions, our 2018 base year expenditure was 16% below our annual opex allowance for the current regulatory period and this translates to lower opex requirements in the 2022-26 regulatory period. These savings will benefit our customers through lower prices, while we continue to deliver a safe, reliable and secure electricity distribution network. The regulatory framework provides powerful incentives to continually seek out opportunities to improve efficiency, without compromising customer service performance or our compliance with regulatory obligations.

We have a strong track record of responding to the incentives provided by the EBSS and driving efficiencies within our network. As a result, our adjusted base year expenditure reflects our efficient recurrent costs in accordance with the AER's preferred forecasting methodology.

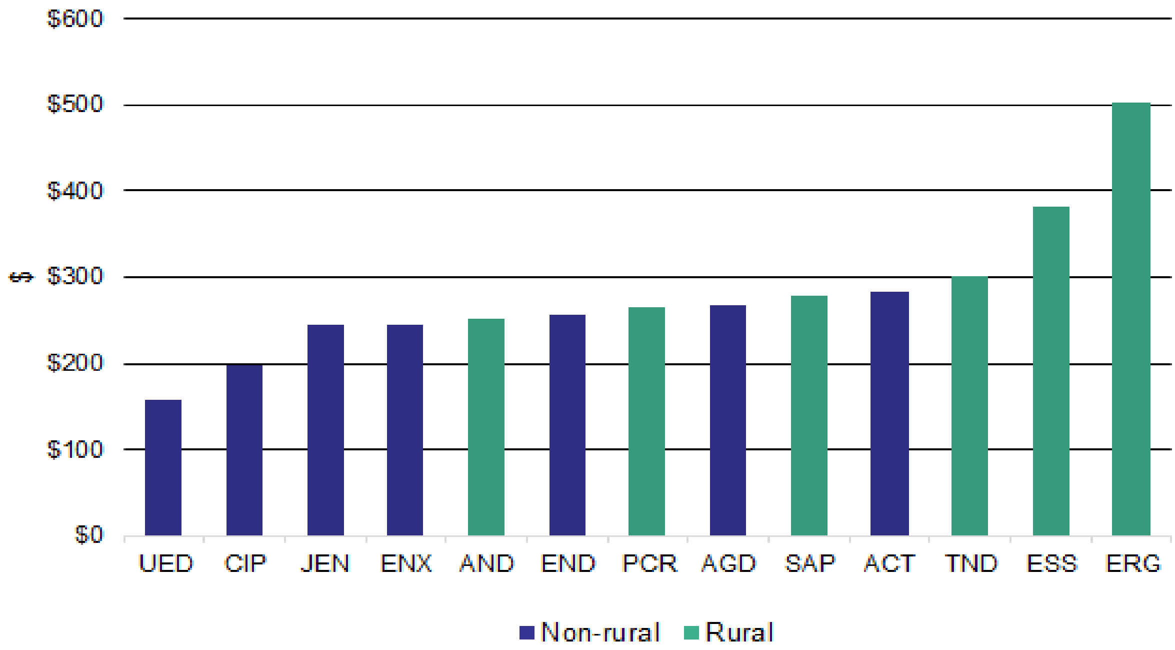
10.8.3 Benchmarking

Each year, the AER compares the costs of the Australian electricity distribution businesses and some international distribution businesses (in New Zealand and Canada). The AER's most recent annual benchmarking report was published in November 2019 and covers the period from 2006 to 2018.

Our analysis of AER data demonstrates that we

We are the lowest opex cost rural distributor in Australia as measured by opex per customer (the actual amount on the bill). The figure below shows all distributors opex costs divided by the number of customers. Unlike in the AER benchmarking report, where substantive amounts of costs customers pay are excluded or adjusted, the chart includes all opex costs that customers actually pay. As an example, in 2018, our opex was relatively low, particularly when considered against the more rural networks.

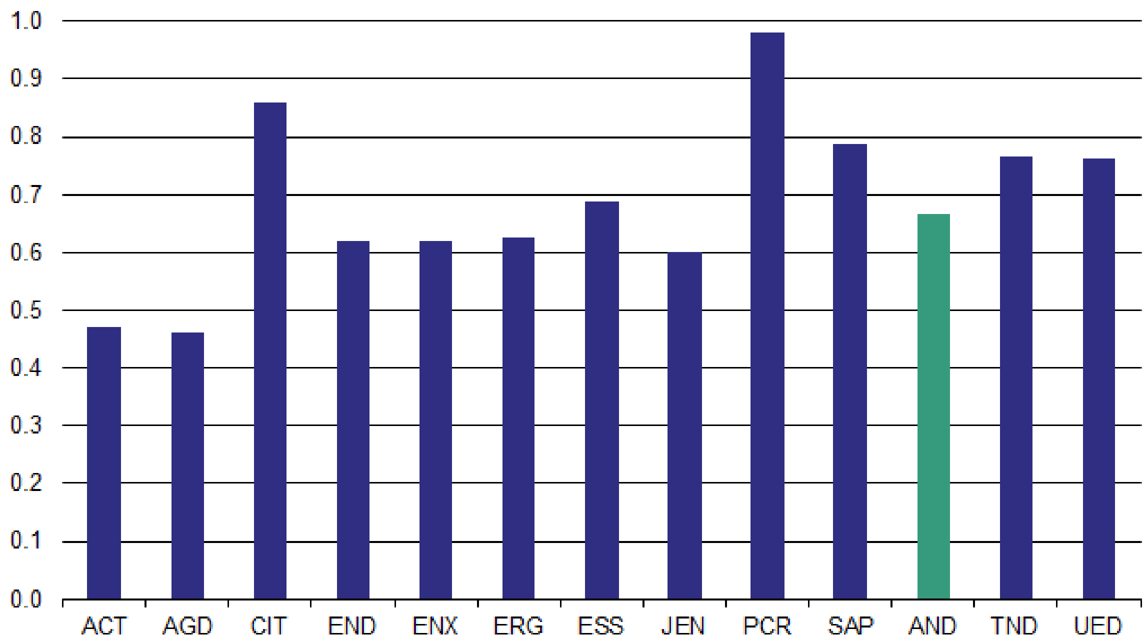
Figure 10-4: Opex per customer



Source: AusNet Services.

The AER's benchmarking report shows that over the 2012-18 period we have been an efficient DNSP as measured by the AER's suite of econometric models. The average of these models over the period 2012-2018 shows that we were the 7th most efficient DNSP (see below).

Figure 10-5: DNSP opex cost efficiency scores, 2012–2018, average of models



Source: AusNet Services.

However, the AER's benchmarking report does not account for several significant operating environment factors which impact our network and so underreport the efficiency of our business. Most importantly the AER's benchmarking report does not adjust for the significant expenditure that we incur on bushfire mitigation. The AER itself recognises the limitations of their measures as a measure of relative efficiency. For example, the AER's 2019 distribution benchmarking report noted that:

> *… our benchmarking models do not directly account for differences in legislative or regulatory obligations, climate and geography. These may materially affect the operating costs in different jurisdictions and hence may have an impact on our measures of the relative efficiency of each DNSP in the NEM.*[10]

In the 2019 benchmarking report, the AER committed to reviewing two key issues that we consider are not appropriately incorporated into our benchmarking performance.

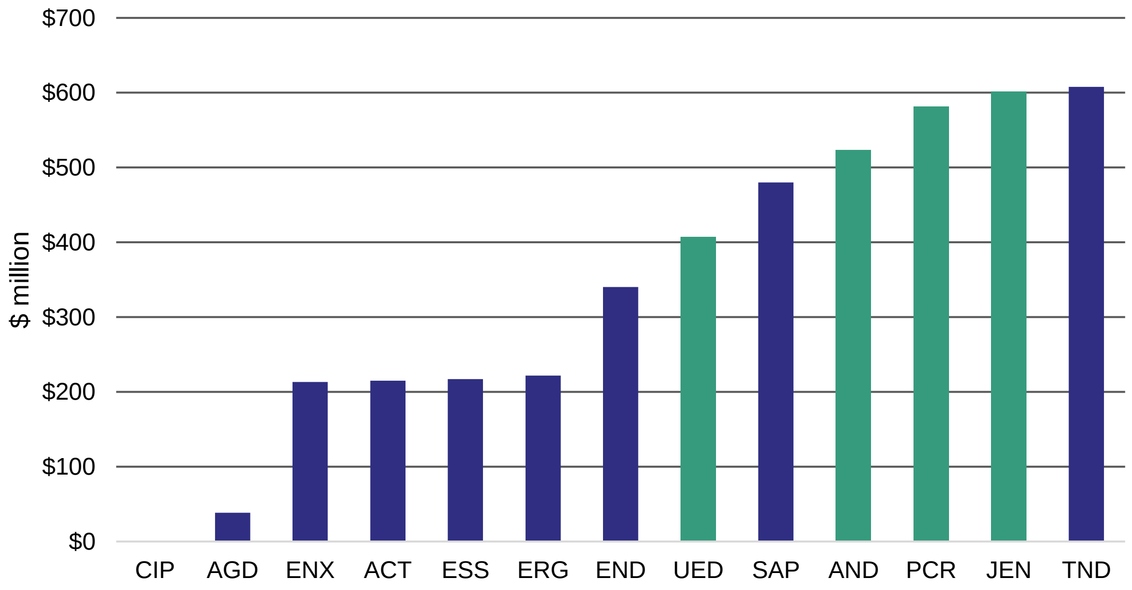
10.8.3.1 Vegetation management

Vegetation management is a significant area of expenditure for us as our distribution network extends through some of the most heavily treed areas of Australia and we face some of the highest bushfire risks in the world.

As highlighted above, the AER agrees that the opex benchmarking excludes adjustments needed to account for the additional opex that we must incur due to factors outside of our control, such as regulatory obligations, climate and geography. One of the most material of these is the bushfire mitigation regulatory obligations which impose significant operating costs due to higher standards of vegetation management and asset inspection. Our vegetation management expenditure as a proportion of total opex has been among the highest in the NEM over the last six year at close to 20% of opex.

If we benchmark our vegetation management against the other Victorian DNSPs (who are subject to the same regulatory regime), we have the second lowest cost per span cut (see figure below). This indicates that our vegetation management expenditure is efficient compared to our peers experiencing similar conditions.

Figure 10-6: Vegetation management expenditure per active span



Source: AusNet Services.

While addressing the bushfire mitigation obligations is the most significant issue, there are other changes needed to the way in which operating environment adjustments are made. For example, there has been a recent change to the classification of our opex for benchmarking to include tax and levies. This means that our OEF relating to tax and levies needs to be re-estimated.

10 AER (2019), Annual Benchmarking Report, Electricity distribution network service providers, November, p. 22.

10.8.3.2 Lack of comparable opex data used for benchmarking

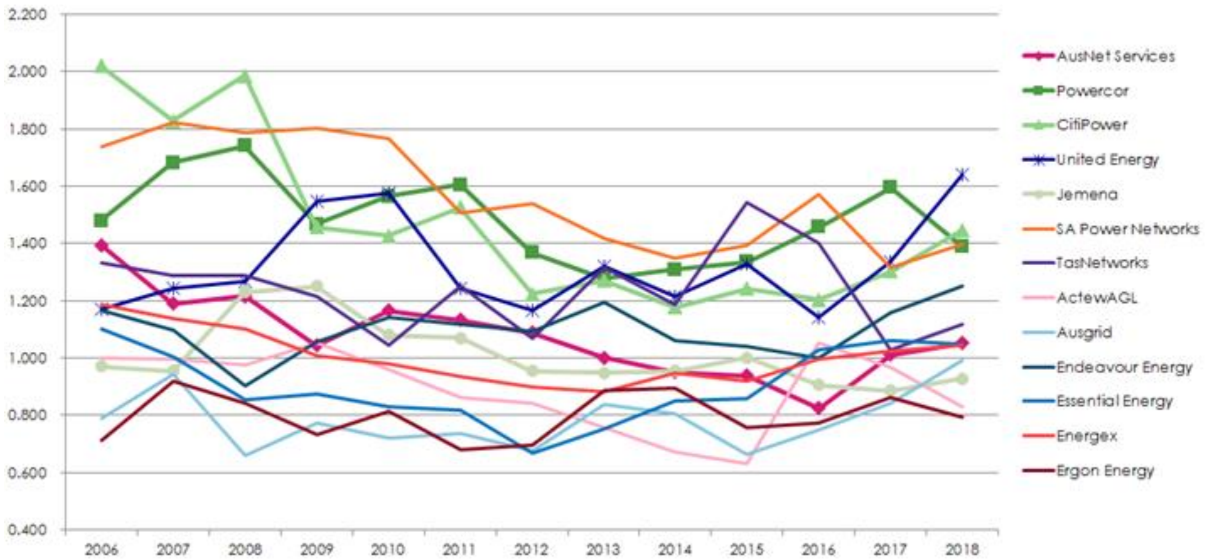
One of the key inconsistencies in the opex data relates to the treatment of overheads. Different businesses adopt very different capitalisation approaches to corporate overheads. These accounting decisions do not impact the underlying productivity of different networks but can materially impact the AER's benchmarking results and assessment of relative productivity.

Compounding this problem, some businesses' actual capitalisation practices are reflected in the benchmarking results, while others are not. This is not transparently presented in the benchmarking reports. We note that all other Victorian DNSPs now expense (opex) rather than capitalise their corporate overheads and the AER has not reflected this change in their benchmarking approach.

Our analysis indicates that if the same corporate overhead capitalisation were applied to all businesses, this would improve our ranking in the most recent opex partial factor productivity (OPFP) scores from 9th to 7th among the 13 distributors. It also would result in the frontier businesses having a reduced gap relative to the rest of the DNSPs. This suggests that different capitalisation policies can materially impact the benchmarked performance.

We welcome the AER's planned review of the impact of different capitalisation policies on benchmarking results.

Figure 10-7: Opex Partial Factor Productivity (OPFP) using the same capitalisation for all DNSPs



Source: AusNet Services.

10.8.3.3 Partial Productivity Indicators

Efficiency can also be demonstrated by examining opex partial performance indicators (PPIs) – which provide a 'top-down' measure of efficiency. PPIs compare individual opex categories between DNSPs and over time. The AER describes these measures as follows:[11]

> *PPI techniques are a simpler form of benchmarking that compare one input to one output. This contrasts with the MTFP, MPFP and econometric techniques that relate inputs to multiple outputs.*
>
> *The PPIs used here support the other benchmarking techniques because they provide a general indication of comparative performance of the DNSPs in delivering a specific output. While PPIs do not take into account the interrelationships between outputs (or the*

11 AER (2019), Annual Benchmarking Report, Electricity distribution network service providers, November, p. 32.

interrelationship between inputs), they are informative when used in conjunction with other benchmarking techniques.

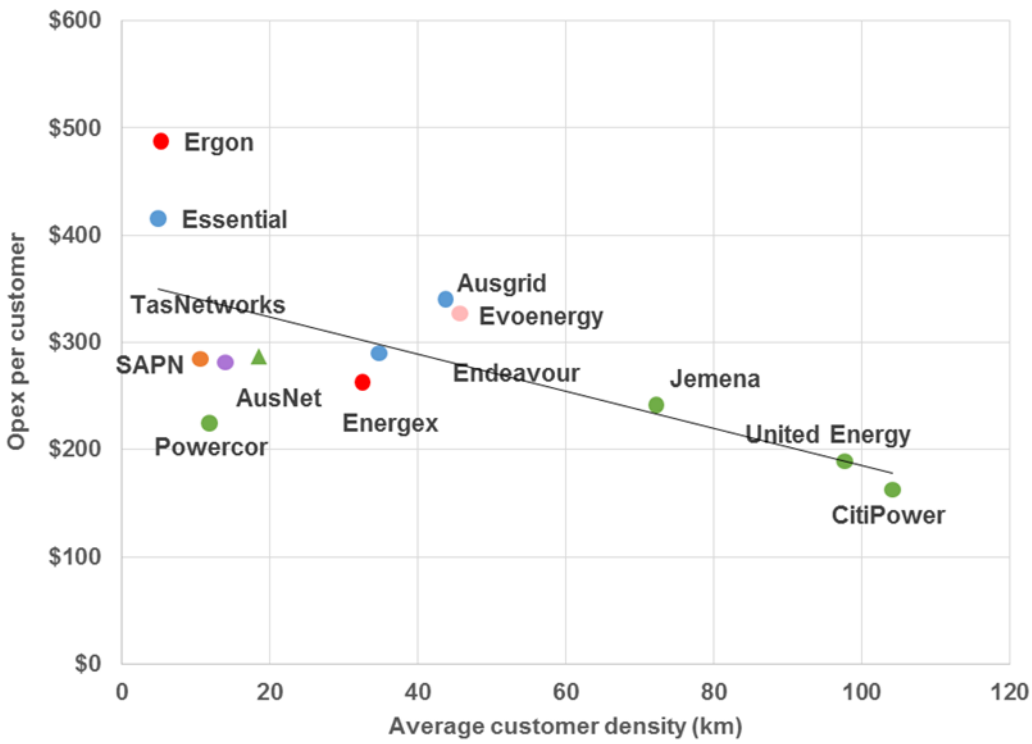
As noted by the AER, differences in cost allocation to opex categories between DNSPs can contribute to differences in category analysis metrics. However, strong performance across all metrics is evidence of an efficient level of total opex. The PPIs demonstrate that we benchmark favourably when compared to businesses of similar customer density and across the NEM.

While these PPIs suggest we are relatively efficient, it should be emphasised that these benchmarks do not adjust for differences in cost allocation between DNSPs. As noted above, these benchmarks are likely to underestimate our relative efficiency.

These comparability issues mean that PPIs should be used as indicative efficiency measures, which may warrant further investigation in the case of poor performance, rather than as definitive measures of efficiency.

The figure below shows average opex from 2009-2018, which has been normalised across DNSPs. This data has been prepared by the AER and presented here to demonstrate our relative efficiency.

Figure 10-8: Opex per customer ($2018) against customer density (2013–18 average)

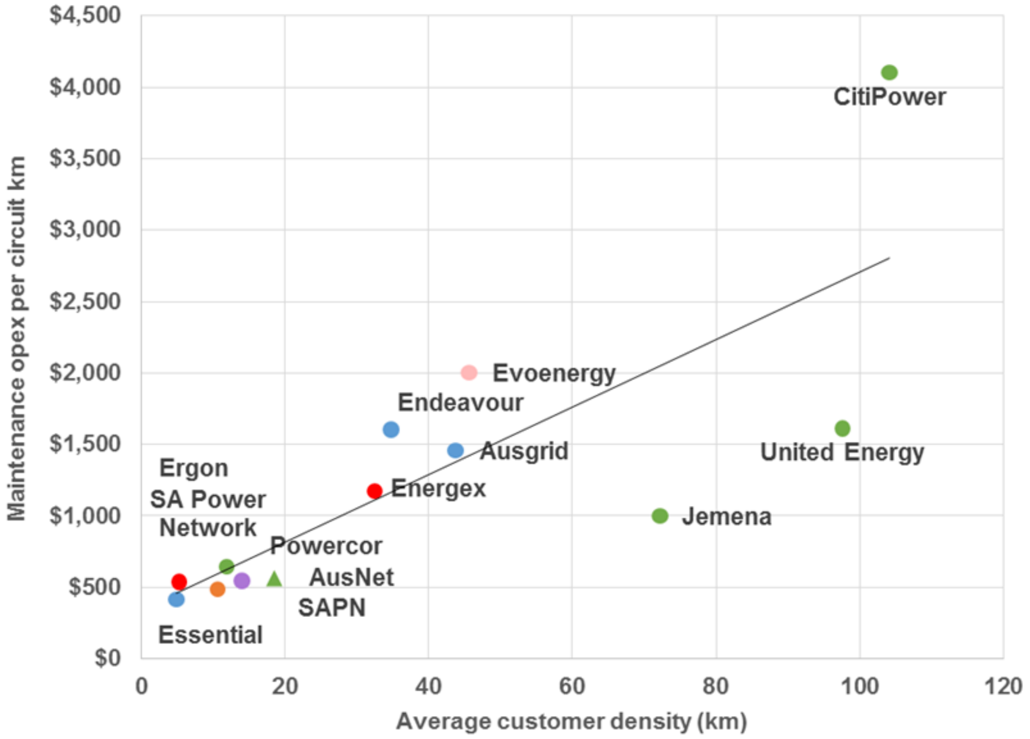


Source: AusNet Services based on AER data.

There is a strong relationship between opex per customer and customer density, with less dense networks having higher opex per customer. The figure above shows that our total opex per customer is lower than trend given the relative density of our network, which indicates that at a total level our opex is efficient.

The figure below shows average maintenance opex from 2009-2017 for major opex categories, which has been normalised across DNSPs.

Figure 10-9: Average maintenance spend per circuit km against customer density ($2018)



Source: AusNet Services based on AER data.

Again, there is a strong relationship between maintenance opex per kilometre and customer density. The figure shows that our total opex per customer is lower than trend given the relative density of our network.

Although benchmarking analysis suffers from measurement difficulties – particularly in relation to bushfire risk and differences in DNSPs' accounting treatments of overheads – there is strong evidence that we are an efficient performer when compared to our peers. Furthermore, we have programs in place to deliver efficiency improvements as we continue to respond to the incentives provided by the regulatory framework.

10.9 Step changes

We propose several step changes for new regulatory obligations, relating to market settlement, cyber security and bushfire safety. Our regulatory proposal includes efficient step change costs to meet these new obligations.

However, there are $21 million ($2021) of additional cost pressures and step changes in opex that we will absorb without any compensating increase in our opex allowance, including:

- The costs associated with an increase in the superannuation guarantee from 1 July 2021. Which are forecast to be approximately $6.5 million ($2021) over the 2022-26 regulatory period.
- Increases in our bushfire insurance. This is forecast to save customers $7 million ($2021) over the 2022-26 regulatory period;
- The costs with implementing a demand management solution at Cranbourne Terminal Station, which are forecast to be approximately $1.5 million ($2021) over the 2022-26 regulatory period.

- The costs involved in demonstrating compliance with the revised Environmental Protection Act. Which are forecast to be approximately $1 million ($2021) over the 2022-26 regulatory period.
- The majority of the costs associated with transitioning to cloud base IT systems. Forecast to be approximately $5.2 million ($2021) over the 2022-26 regulatory period. The partial recovery of these costs through a step change is discussed in section 10.9.4.

Absorbing approximately $21.2 million ($2021) of additional costs within our existing opex allowance delivers real additional productivity benefits to our customers and is a tangible response to the affordability concerns of our customers.

10.9.1 REFCL program

As noted in Chapter 9, we are rolling out REFCL technology to deliver bushfire mitigation benefits to Victoria and our customers. We will meet our obligations under the *Electricity Safety Act 1998* and the bushfire mitigation regulations by installing REFCLs at 22 of our zone substations and their associated networks. The REFCL program is to be delivered in three tranches to align with compliance dates of 1 May 2019, 1 May 2021 and 1 May 2023 (as required by Government Regulations). A final project Final Project Assessment Report for Tranche 1 of the REFCL program has been completed.[12]

Following the completion of the installation program, we are required to undertake annual compliance testing of the REFCLs.[13] This annual testing is necessary to ensure the safe operation of this equipment during periods of high bushfire risk. Additionally, we must now maintain much stricter capacitive balance on REFCL protected networks, for the purpose of ensuring the network remains within the operating tolerances for REFCL operation. This requires us to conduct an annual assessment of network balance and may require some line balancing works each year if an imbalance occurs due to network growth or reconfiguration.

The roll forward of the base year included the approved opex allowances from Tranche 1, Tranche 2 and Tranche 3 Contingent Project Applications for the 2016-2020 regulatory period. Our step change proposal only accounts for the increased amounts above these already approved amounts.

In our contingent project applications for Tranche 2 and Tranche 3 we forecast costs that were in the next regulatory period. The AER's decision on the existing regulatory period did not account for these further increases after the end of the current regulatory period. Our proposed step change is based on the cost information provided with the Tranche 2 and Tranche 3 contingent projects and only includes those costs (previously identified) above what was approved by the AER in the current regulatory period.

This program meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex. This step change is recurrent in nature and is not captured in the output growth, productivity or real price changes. The REFCL program is safety driven and does not result in an increase in the output growth parameters or deliver productivity benefits to us as it is a compliance based program. The step change is allocated to the Network Operating Costs expenditure category.

As a regulatory obligation this step change is necessary to comply with clause 6.5.6(a)(2) of the NER, as such a do-nothing option was not considered in relation to this step change.

13 Electricity Safety (Bushfire Mitigation) Regulations 2013, regulation 7(1)(hb).

Table 10-5 Proposed REFCL step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
REFCL Step Change	0.9	1.1	1.3	1.3	1.3	6.0

Source: AusNet Services.

10.9.2 Five Minute and Global Settlement

In the NEM, there is currently a mismatch between dispatch and settlement periods. Dispatch prices are calculated every five minutes, while the market is settled on the basis of the time-weighted average of the six five-minute dispatch prices over the 30-minute trading interval.

The Australian Energy Market Commission (AEMC) has amended the Rules to align operational dispatch and financial settlement to occur at five minute intervals.[14] There is a transition period of three years and seven months. Additionally, there are changes to the current retail settlement framework, known as 'settlement by differencing'. The move to global settlement requires that all energy usage is accounted for and billed to an accountable party. This change will incentivise flexible, responsive loads and generators to respond to changes in the electricity market. This is expected to create further opportunities for demand management and innovation in electricity markets, which will in turn increase customer opportunities for participation in the market and potentially dampen future augmentation requirements.

Our preferred option for addressing these new regulatory obligations is to make the minimum number of changes to the current metering systems necessary to achieve compliance with the AEMC's rule change. This primarily requires the reconfiguration of:

- the Meter Management System (MMS) which is currently configured to receive regulated non-contestable Type 5 meter data at 30-minute data intervals. This will be reconfigured to support the collection of 6-times the historical data volume as the market shifts to 5 minute settlement. The MMS will need to be upgraded to the next version, along with increases to server processing and storage capacity increases to manage the data increase.
- the Meter Data Management system (MDMS) to process this increased data and publish the metering data to the market, aligned with data validation regulatory requirements. This includes changes to support the transition from 30 minute interval data to 5 minute interval data.

The opex step change relates to opex for implementation and the new and ongoing support costs for the upgraded systems. This program meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex. This step change is recurrent in nature and is not captured in the output growth, productivity or real price changes. This program does not result in an increase in the output growth parameters or deliver productivity benefits to us as it is a compliance based program. The step change is allocated to the IT expenditure category.

As a regulatory obligation this step change is necessary to comply with clause 6.5.6(a)(2) of the NER, as such a do-nothing option was not considered in relation to this step change.

Full details of the requirements of this project (including the necessary capex and opex) can be found in the IT project scope.[15]

14 National Electricity Amendment (Five Minute Settlement) Rule 2017 No. 15.

15 Program Brief 5 Minute Global Settlement PUBLIC VERSION.docx.

Table 10-6: Proposed 5 Minute Settlement Step Change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
5 Minute Settlement Step Change	1.0	0.8	0.5	0.7	0.7	3.6

Source: AusNet Services.

10.9.3 Cyber security

Our electricity distribution network is a part of Australia's national critical infrastructure. The safety and reliability of electricity supply is integral to the lives of Victorians. The current and emerging regulatory cyber security laws and guidelines that require ongoing organisational response and compliance include:

- the *Security of Critical Infrastructure Act 2018* (Cth);
- *Privacy Act 1988* (Cth);
- the EU General Data Protection Regulation; and
- ASIC Cyber Resilience: Health Check, Report 429, released in 2015.

Possible threats to our network are multi-fold and include cyber terrorism, denial of service, extortion and cyber vandalism. With the introduction of Distributed Energy Resources (DER) and Advanced Metering Infrastructure (AMI), the number of connection points into the network has increased. Each of these connection points can act as an attack vector if the perpetrators manage to compromise devices such as meters to get into our networks.

A critical tenet of our operations, given our designation as critical national infrastructure, is to uphold the security, reliability and in turn continuity of supply. This is consistent with the National Electricity Objective, which states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—*
>
> > *(a) price, quality, safety, reliability and security of supply of electricity; and*
> >
> > *(b) the reliability, safety and security of the national electricity system.*

By upholding the security of critical systems which manage, monitor and control the network, we are able to meet basic customer expectations of our network. We will continue to focus resources and intensify efforts to prevent cyber attacks on the network, including by undertaking a number of critical programs of work to proactively detect and deter threats, as well as uplifting overall governance and access controls, while maintaining the security and privacy of customer data.

We anticipate that AEMO will impose a regulatory obligation on us that we must uplift our cyber security capability to a Maturity Indicator Level 3 (MIL 3). The next steps identified in the AEMO 2018 summary report into the cyber security preparedness of the national and WA Wholesale Electricity Markets identified the consideration of potential regulatory models to strengthen AEMO's authority to manage cyber security risk as one of the next steps. This is piece of work is continuing.[16] MIL 3 is the highest level of maturity in the Cybersecurity capability maturity model. We have benchmarked our security maturity level of capability against the Cybersecurity Capability Maturity Model and reaching and maintaining this level of maturity will require a step increase in resourcing. AEMO has not yet imposed this regulatory obligation, but we anticipate it being announced around March 2020. We will have established a security team combining a mix

[16] https://www.aemo.com.au/-/media/Files/Cyber-Security/2018/AEMO-2018-AESCSF-Report.pdf.

of cyber risk, architecture, compliance, advisory, and cyber security engineers by the beginning of the period to carry forward the initiatives to progress towards MIL 3. This will require a step change to support for these resources.

This program meets the AER definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex. This step change is recurrent in nature and is not captured in the output growth, productivity or real price changes. While this will underpin the security of our network, this program does not result in an increase in the output growth parameters or deliver productivity benefits to us as it is a compliance based program. The step change is allocated to the IT expenditure category. As a regulatory obligation this step change is necessary to comply with clause 6.5.6(a)(2) of the NER, as such a do-nothing option was not considered in relation to this step change.

Full details of the requirements of this project (including the necessary capex and opex) can be found in the ICT cyber security program brief that forms part of our proposal.[17]

Table 10-7: Proposed cyber security step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Cyber Security Step Change	1.1	1.1	0.9	0.8	0.8	4.7

Source: AusNet Services.

10.9.4 IT cloud step change

IT software is increasingly moving to cloud based software as a service approach. Cloud based systems are opex solutions rather than the traditional capex approach, whereby we purchased and maintained our IT equipment and services. In our Draft Proposal we included $7.85 million of additional costs associated with transitioning to the cloud. The Customer Forum only agreed to $2.6 million in additional costs, related to the roll out of a Customer Relationship Management (CRM) IT system and Outage Management system. We have now agreed to absorb the remainder of the additional cloud costs within our existing opex allowance. As such, this step change only relates to the costs agreed with the Customer Forum. Detailed cost build-ups and options analysis (including a do nothing options) are included in the attached program briefs.[18] We have proposed the option with the highest NPV and so this reflects the prudent and efficient alternative.

The requirement for the cloud transition is not internally driven. Rather, it comes as a result of changes in the way products are provided by our vendors, and this is happening internationally. Where a business is seeking new functionality, it will often be necessary to adopt cloud solutions as this is increasingly how ICT services are offered – that is, an on-premises solution will not exist.

The cloud-based systems we propose underpin our ability to deliver the improved customer outcomes agreed with the Customer Forum, and reflect strong customer preferences for better communication. For example, our commitments to improve the way we manage of outages and communications with sensitive customers (such as vulnerable and life support customers) requires us to consolidate of customer information that is currently dispersed across different systems and to incorporate it with new customer information into a single, user-friendly cloud-based data repository.

[17] Program Brief Cyber Security Program PUBLIC VERSION.docx.

[18] Program Brief Customer Information Systems PUBLIC VERSION2.docx, Program Brief - Outage Management PUBLIC VERSION.docx.

This program meets the AER definition of a forecast opex step change as it is a capex/opex trade-off and results in lower capex in the next regulatory period (compared to a counterfactual where we procure these as a capex solution). This step change is recurrent in nature and is not captured in the output growth, productivity or real price changes. This step change reflects a change in the way IT services are provided and this program does not result in an increase in the output growth parameters or deliver productivity benefits to us. The step change is allocated to the IT expenditure category.

Table 10-8: IT cloud step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
IT Cloud Step Change	0.5	0.5	0.5	0.5	0.5	2.6

Source: AusNet Services.

10.9.5 Bushfire Stand Alone Power System (SAPs) step change

We are currently considering whether the installation of Stand Alone Power Systems is a preferable solution to rebuilding overhead lines following recent bushfire damage to parts of our network. It is possible that in remote parts of the network these systems could avoid significant capital expenditure and deliver other benefits to customers.

We note the regulatory framework around SAPs is currently evolving and the AEMC has made a draft package of proposed rule changes to enable distribution network businesses to supply their customers using SAPS where it is cheaper than maintaining a connection to the grid.[19] These rules changes are expected to be fully implemented by mid-2021. If these solutions were adopted, additional ongoing 'network support'-type opex to procure services from third party providers would be incurred, and potentially additional capex. As such, we are raising this as an issue we may need to address in our revised proposal.

10.10 Bottom-up forecasts

We have forecast several categories of costs using a category specific forecast. This is consistent with the approach taken in the 2016-2020 regulatory period.[20]

10.10.1 GSLs

Under the Electricity Distribution Code administered by the Essential Services Commission of Victoria (ESC), we are subject to Guaranteed Service Level payments (GSLs) for certain services we offer to our customers. The GSLs set minimum standards for appointments, new connections, supply restoration and sustained and momentary interruptions. If these standards are not met for an individual customer, the Code requires us to give financial compensation to that customer by way of a GSL payment.

We have forecast our proposed GSL payments using the average of actual GSL payments over the last five years (i.e. from 2014 to 2018). This is consistent with the approach approved by the AER in the 2016-2020 electricity distribution price review.

Following feedback from the Customer Forum, we have committed to absorbing the cost of GSLs that the forum considers are entirely within our control (for missed appointments and slow

19 https://www.aemc.gov.au/market-reviews-advice/updating-regulatory-frameworks-distributor-led-stand-alone-power-systems.

20 AER, Final Decision AusNet Services distribution determination 2016 to 2020 Attachment 7 – Operating expenditure, p. 7-24.

connections processed) from our bottom line.[21] By agreeing to absorb the cost of controllable GSLs, we are ensuring that our customers do not have to fund poor performance against these metrics.[22] Accordingly, we have reduced our forecast of GSL costs by $0.5 million over the 2022-26 regulatory period.

Importantly, on 13 August 2019, the ESC published an issues paper in its Electricity Distribution Code review that contemplates significant changes to the existing GSL scheme.[23] Depending on the outcomes of this review, we may need to materially change our forecast expenditure on GSLs.

Table 10-9: Forecast GSL costs ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
GSL costs	9.3	9.3	9.3	9.3	9.3	46.7

Source: AusNet Services.

10.10.2 Forecast Debt Raising Costs (DRC)

As explained in Chapter 14 – Rate of Return, we have adopted the AER's benchmark approach to calculating benchmark debt raising costs (see table below).

Table 10-10: Proposed Debt Raising Costs ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast DRC costs	**2.3**	**2.3**	**2.4**	**2.4**	**2.4**	**11.8**

Source: AusNet Services.

10.10.3 Metering systems reallocation

We are leveraging our AMI data to enhance the delivery of our standard control services, including through improving network planning, demand forecasting and network operations.

For the current regulatory period, the AER accepted that a portion (36%) of our metering system costs should be allocated to standard control services.[24] However, the trend to using this data in the delivery of standard control services is continuing to increase. Consequently, we do not consider the apportionment used in the 2016-20 decision will reflect the usage in the 2022-26 regulatory period.

Therefore, the allocation used in the 2016-20 regulatory period needs to be updated. Additionally, we consider that the AER's decision should allow for a more flexible approach to allocating these costs within the 2022-25 regulatory period, which is consistent with our Cost Allocation Methodology. Our proposed reallocation is explained further in appendix 9D.

Our proposed approach will ensure that the allocation of costs accurately reflects the usage of the systems as it changes over time. As already explained, while this reallocation of costs

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21 The controllable GSLs are for appointments where we are more than 15 minutes late (clause 6.1.1 of the Code) and failing to supply electricity on the day agreed with the customer (clause 6.2).

22 This does not alter or remove our obligation to make these payments.

23 Essential Services Commission, *Electricity Distribution Code Review, Issues Paper*, 13 August 2019, https://www.esc.vic.gov.au/sites/default/files/documents/electricity-distribution-code-review-issues-paper-20190813_1.pdf.

24 AER, FINAL DECISION AusNet Services distribution determination 2016 to 2020 Attachment 7 – Operating expenditure, pp. 7-47.

increases our opex allowance it is offset by an equivalent reduction in the cost of our metering services.

Table 10-11: Proposed metering ICT cost reallocation ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Metering ICT cost reallocation	**5.7**	**5.7**	**5.9**	**6.0**	**6.1**	**29.4**

Source: AusNet Services.

10.10.4 Innovation expenditure

We have included an allowance for innovation expenditure in our opex proposal for the 2022-26 regulatory period. The Customer Forum has agreed that we can propose up to $7.5 million on the basis that it is only spent on innovation and any unspent allowance is returned to customers if not spent. This expenditure is in addition to innovation projects associated with demand management under the DMIA.[25]

The proposed innovation expenditure will enable us to prepare for, and efficiently respond to, the unprecedented changes already taking place on our network. In particular, we will focus on innovation that maximises the benefit and revenue customers can receive for their own investments behind the meter and on innovative ways to improve customer service and allow non-solar customers to also benefit from these investments. Research consistently shows that maximising the value of DER investments to the community is a strong preference for our customers.

We have forecast the efficient cost of our proposed innovation projects on a bottom-up basis. The proposed expenditure totals $7.5 million in $2021 over the 2022 to 2026 regulatory period. A portion ($1.2 million) of this expenditure relates to conducting trials, so it is classified as operating expenditure, although it may lead to future capital projects. Further details of our proposed innovation expenditure is provided in Chapter 11.

Table 10-12: Proposed innovation expenditure ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast innovation expenditure	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**1.2**

Source: AusNet Services.

10.11 Trend growth

The rate of change, which is applied to base year opex for each year of the forthcoming regulatory period, accounts for expected real increases in labour and materials costs, opex increases attributable to network growth (scale escalation) and expected changes in productivity. In line with the AER's Expenditure Forecast Assessment Guideline, the rate of change has been calculated according to the following formula:

- Rate of change = (1+output growth) * (1+ real price growth) *(1 + productivity growth)[26]

25 The DMIA is set-out in chapter 16 Incentive Schemes.

26 AER, *Expenditure Forecast Assessment Guideline*, p. 23.

The table below sets out our proposed rate of change escalators.

Table 10-13: Proposed rate of change

Component	2021-22	2022-23	2023-24	2024-25	2025-26
Output growth	1.51%	1.41%	1.54%	1.36%	1.08%
Real price growth	0.57%	0.61%	0.64%	0.56%	0.53%
Productivity growth	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%
Overall Rate of change	1.58%	1.52%	1.68%	1.42%	1.10%

Source: AusNet Services.

We explain each of the elements in the rate of change calculation below.

10.11.1 Real price growth

This parameter accounts for the expected increases in labour rates as well as escalation in the price of materials. We have applied a benchmark input price weights of 59.7% labour prices and 40.3% materials costs to combine these into the real price growth parameter.

10.11.1.1 Labour escalation

We expect labour price to grow faster than CPI over the 2022-26 regulatory period. We have relied on advice from BIS Oxford Economics, one of Australia's leading providers of industry research, analysis and forecasting services.[27] BIS Oxford Economics has built up a rigorous forecast of expected labour price growth in the Electricity, Gas, Water and Waste Services (EGWWS) sector in Victoria based on expected macroeconomic and state specific factors. BIS Oxford Economics has found that the National and Victorian utilities wages are forecast to increase by more than the national and state all industries averages because of the following factors:

- The electricity, gas and water sector is a largely capital intensive industry whose employees have higher skill, productivity and commensurately higher wage levels than most other sectors.
- Strong union presence in the utilities sector will ensure collective agreements, which cover 65% of the workforce, remain above the wage increases for the national 'all industry' average. In addition, with the higher proportion of employees on enterprise bargaining agreements (EBAs), compared to the national average (38%), and EBAs wage rises normally higher than individual agreements, this means faster overall wage rises in the EGWWS sector.
- Increases in individual agreements (or non-EBA wages) are expected to strengthen from the current weak pace as the labour market tightens and labour productivity growth builds from early next decade.
- Demand for skilled labour has picked up and will strengthen with the large increases in utilities investment over 2017/18 to 2020/21, with investment levels expected to remain elevated over the medium term. This will also be a key driver of wages going forward.
- The overall national average tends to be dragged down by the lower wage and lower skilled sectors such as Retail Trade, Wholesale Trade, Accommodation, Cafés and Restaurants,

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[27] BIS Oxford Economics, Labour Cost Escalation Forecasts 2025/26, Prepared by BIS Oxford Economics for Citipower, Powercor, United Energy and AusNet Services, Final April 2019.

and, in some periods, also Manufacturing and Construction. These sectors tend to be highly cyclical, with weaker employment during downturns impacting on wages growth in particular. The EGWWS sector is not impacted in the same way due to its obligation to provide essential services and thus retain skilled labour.

Until recently the AER has been applying an average of the estimates in two consultant reports to make its decisions on the labour price escalation.[28] However, in its draft decision for South Australia Power Networks (SAPN), the AER relied upon only its consultant's report in making its draft decision.[29] The AER's decision indicated that Deloitte Access Economics has had a better track record of forecasting WPI at a national level and therefore they made a decision to use this (being their) consultant's report.

We have attached a report from Frontier Economics that replicates the AER's analysis, but applies it specifically to Victoria.[30] This analysis demonstrates that in Victoria, BIS Oxford has been more accurate with its forecasts than DAE.[31] Therefore, consistent with the AER's reasoning in the SAPN draft decision, the BIS Oxford forecasts should be used in Victoria. However, the evidence suggests that the average of DAE's and BIS's past forecasts would have resulted in more accurate outcomes than exclusive reliance on either of those advisers' forecasts individually. For this reason, we consider the AER should continue to rely on an average of the two consultant's forecasts, rather than exclusively relying on one forecast. However, if the AER does choose to apply a single forecast, it is BIS Oxford, not DAE, which should be applied in Victoria.

We have previously committed to the Customer Forum that we will adopt the average of the BIS Oxford Economics report and a report prepared for the AER. We have not changed this position as a result of the AER's recent decision or the analysis undertaken by Frontier Economics. For this regulatory proposal, we have used the labour escalation report prepared for the AER's SAPN draft decision.[32] This placeholder will be updated in our revised proposal with any revised report prepared for the AER. This forecast of WPI includes labour productivity growth within the forecast and so applying the AER's productivity adjustment to this forecast is appropriate. As required by the RIN, we have also attached our two current Enterprise Bargaining Agreements (EBAs), both of which are set to expire before the commencement of the forthcoming regulatory period. The annual wages outcomes in these existing EBA's are higher than the forecast we have used for the forthcoming regulatory period. Commencement of renegotiation of these EBAs is due to commence six months prior to their expiry.

Materials escalation

Non-labour costs comprise a range of cost categories, including materials, motor vehicle expenses, media and marketing costs and land and building leases. These materials costs account for around 40% of base opex.

For the 2022-26 regulatory period, we forecast that these costs will increase at the same rate as CPI. In our view, this forecast is the best estimate of the efficient costs that a prudent DNSP would incur for non-labour costs over the forthcoming regulatory period. Accordingly, we forecast no real change in non-labour costs for the forthcoming regulatory period.

10.11.2 Output growth

Our network costs increase as our network assets and customer numbers grow. The AER has standardised a methodology to calculate growth related costs, based on forecast increases in

28 AER, Final Decision, AusNet Services distribution determination 2016 to 2020 Attachment 7 – Operating expenditure May 2016.

29 AER, Draft Decision, SA Power Networks Distribution Determination 2020 to 2025 Attachment 6 Operating expenditure, p. 21.

30 Frontier Economics, Assessment Of The AER's Approach To Forecasting Labour Escalation Rates, A Report Prepared For Jemena, AusNet Services, Citipower, Powercor And United Energy.

31 Ibid.

32 Deloitte Access Economics, Labour Price Growth Forecasts, Prepared for the Australian Energy Regulator, 24 June 2019.

customer numbers, circuit length, maximum demand and energy throughput. The AER acknowledges that:

> *"Increased demand for NSPs' outputs may require them to expand their networks. It is reasonable that an efficient NSP will require more inputs, and thus greater opex, to deliver more output. We therefore include forecast output growth in the rate of change formula."* [33]

We agree with the AER that the rate of change needs to account for growth in our opex forecasts. The AER's benchmarking models seek to estimate the relationship between inputs and outputs and so capture the relationship economies of scale and the growth drivers. As an example, the growth in customer numbers expected from 2022 to 2026 will create additional customer service costs. Increasing circuit length increases the number of assets that must be maintained and increasing maximum demand requires higher capacity infrastructure to be installed (within the same geographic footprint), which also bring increased maintenance costs. To the degree that economies of scale mitigate these cost increases, the AER's econometric methods should capture this relationship. We have adopted a multiple output growth driver based on four of the AER's economic models, the inputs and weights for these growth drivers are setout below. Key assumptions underpinning this approach are set out below.

Table 10-14: Proposed rate of change

Component	2021-22	2022-23	2023-24	2024-25	2025-26
Customer Numbers	1.72%	1.69%	1.68%	1.67%	1.66%
Circuit Length	0.80%	0.79%	0.79%	0.78%	0.78%
Ratcheted Maximum Demand	1.75%	1.42%	1.97%	1.23%	0.05%
Energy Throughput	-0.45%	-0.53%	-0.49%	-0.38%	-0.35%

Source: AusNet Services.

We have adopted the weights from the rates using the specification and weights from four models presented in 2018 Annual Benchmarking Report ‐ Data Update and this is consistent with the AER's most recent decision.

33 AER, Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013.

Table 10-15: Weights - derived from economic benchmarking models

Component	SFA CD	LSE CD	LSE TLG	MPFP
Customer Numbers	71.71%	68.71%	57.74%	31.00%
Circuit Length	12.65%	10.76%	11.27%	29.00%
Ratcheted Maximum Demand	15.64%	20.53%	30.99%	28.00%
Energy Throughput				12.00%

Source: AusNet Services.

10.11.3 Productivity adjustment

The AER's final decision in its productivity review specifies an adjustment for the shift in the productive frontier of 0.5% per annum. The AER stated:[34]

> *This reflects the best estimate of the opex productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward, rather than any efficiency catch-up by individual distributors.*

We disagree with the AER's analysis underpinning its adjustment and consider that there is no reasonable expectation of a shift in the productive frontier in the next regulatory period. Our key issue is that we consider that the analytical approaches used by the AER have conflated efficiency catch-up with a shift in the productive frontier and so have overestimated the expected frontier shift. We caution that additional work is needed to improve the robustness of the AER's approach to forecasting productivity shifts in the future. A continuation of the AER's existing approach in future regulatory periods will set overly ambitious productivity targets that are not achievable on an ongoing basis by efficient DNSPs.

Notwithstanding these concerns, our Customer Forum has pushed us to deliver the benefits of our recent efficiency savings to our customers faster. As a result of these negotiations, we have agreed with the Customer Forum that we will apply the final outcome of the AER's productivity review in the 2022-26 regulatory period. Accordingly, we have applied a productivity adjustment of 0.5% per annum to our opex forecast.

In addition to the 0.5% productivity adjustment, we have agreed with the Customer Forum to absorb an additional $21 million in costs, which brings the effective productivity adjustment to above 1%. We have been able to agree to this additional productivity adjustment on the basis that elements of our non-recurrent IT expenditure program will assist to deliver part of the productivity gain.

10.12 Compliance with section 71YA

We are required to be compliant with Section 71YA of The NEL. This requires that where any expenditure or cost has been incurred or is forecast to be incurred by us, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL, we must identify the expenditure or cost and provide a statement attesting that we have not:

34 AER, Final decision paper, Forecasting productivity growth for electricity distributors, March 2019.

- included any of that expenditure or cost, or any part of that expenditure or cost, in the capital or operating expenditures contained in its regulatory proposal; and
- recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and
- sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users.

As we did not incur any relevant expenditure in the 2018 base year this has not impacted on our forecast expenditure in the 2022-26 regulatory period. And, as noted in Chapter 16, we have adjusted the EBSS to ensure compliance with this clause.

10.13 Why our opex forecasts satisfy the Rules requirements

The Rules require the AER to assess the prudency and efficiency of our operating expenditure, having regard to 'operating expenditure factors'. These factors include:

- The most recent annual benchmarking report that has been published and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory period;
- The actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory periods;
- The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;
- The relative prices of operating and capital inputs;
- The substitution possibilities between operating and capital expenditure;
- Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;
- The extent to which the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;
- Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);
- The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options
- Any relevant final project assessment report; and
- Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing.

As the AER is required to consider these factors in determining whether it is satisfied that the forecasts reasonably reflect the operating expenditure criteria[35], we have considered all those factors in developing our forecasts. In particular, we note:

- Our forecasting approach is consistent with the AER's preferred methodology (the base, step and trend forecasting approach).
- We have selected 2018 as the base year on the basis that it a prudent and efficient level of expenditure. Benchmarking of the 2018 base year shows that we are an efficient business,

35 National Electricity Rules, clause s 6.5.6(a) and (c).

noting that our costs are unavoidably affected by extreme bushfire risk and low customer density. We have been driving significant opex efficiencies in our business, which has enabled us to deliver cost savings to our customers in the 2022-26 regulatory period, without compromising the quality of services we deliver to our customers.

- We have identified a limited number of new regulatory obligations that impose cost increases that warrant step changes in our opex allowance. We have absorbed a number of emerging cost pressures within our forecast without seeking additional step changes. As this expenditure is not contained in our base year expenditure and our base year expenditure is reasonably efficient, a forecast opex that does not contain the proposed step changes would not provide us a reasonable opportunity to recover our prudent and efficient expenditure.
- We have proposed a step change for Cloud IT costs, as on premises capex solutions are increasingly replaced by this service delivery model. This reflects an ongoing substitution from capex to opex solutions in the ICT space. As this expenditure is not contained in our base year expenditure and our base year expenditure is reasonably efficient, a forecast opex that does not contain the proposed step changes would not provide us a reasonable opportunity to recover our prudent and efficient expenditure.
- Our operating expenditure proposal does not include any expenditure targeted at increasing reliability and instead is based on maintaining reliability at the current levels consistent with the operation of the STPIS.
- We have negotiated a number of opex issues with the Customer Forum and reached a shared view, which is reflected in this Regulatory Proposal. As explained in Part I of this Regulatory Proposal, our advanced approach to customer engagement has produced a more customer oriented proposal that meets the Rules requirements.

10.14 Supporting documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documentation is provided in support of this chapter:

- ASD - 2021-26 Proposal Opex model - Final - Public.xlsm;
- ASD - BIS Oxford - Labour Cost Escalation Forecasts - Public.docx
- ASD - Frontier - AER method for forecasting labour escalation rates - Public.pdf

A significant number of other supporting documents, including models and program briefs also form part of this proposal.

11 Innovation

11.1 Key points

- Innovation, whether trialling new technologies or research and development, is key to ensuring greater customer value over the long-run in a rapidly changing energy environment. Innovation will be needed to:
  - respond to the rapidly decentralizing energy system;
  - allow the two-way exchange of electricity and new business models using our network to benefit all customers;
  - keep network costs down while adapting to this change; and
  - protect and maintain secure and reliable network services.
- Given the scale and pace of change and lack of secure funding under the current regulatory framework, more formalised innovation funding arrangements are required, as set out in this proposal. Our innovation proposal may test the flexibility of current regulatory approaches, despite being consistent with the regulatory framework which gives primacy to the long-term interests of consumers.
- Innovation was in scope of the expenditure negotiations between us and the Customer Forum. However, it is outside the scope of the negotiations that were oversighted by the Australian Energy Regulator (AER). Nevertheless, the AER has provided significant feedback and guidance on this topic.
- In this environment of customer-led network transformation, the $7.5 million ($2021) of proposed innovation funding being sought in this proposal is modest and is highly likely to provide customers with a net benefit. The benefits of innovation are by nature uncertain, but have the potential to be extremely large. Customers have also indicated a willingness to pay for it.
- In agreement with the Customer Forum, we have focused our innovation projects on addressing DER uptake and the energy sector transition, which are the areas of greatest concern to customers. Where there was weaker customer support (e.g. for electric vehicles preparation), this is not in our proposed innovation program.
- The Customer Forum support our innovation expenditure proposal for a maximum, dedicated allowance of $7.5 million ($2021) that is to be spent on nine projects focused on meeting the numerous network challenges that increased DER take up presents.
- We have also agreed strong governance arrangements based on Ausgrid's governance approach for innovation. It will provide ongoing customer input, strengthened coordination across the Victorian distribution businesses and systematic sharing of innovation learnings across the industry. We will establish an Innovation Advisory Committee (IAC) whose role will be to evaluate and prioritise our proposed innovation projects.
- The $7.5 million ($2021) of innovation funding sought must be used for innovation projects in the 2022-26 regulatory period or the funds will be returned to customers. This means that the $7.5 million will not be reflected in our base opex in the 2027-31 regulatory period. In addition, the proposed innovation expenditure is excluded from the operating and capital expenditure incentive schemes.
- To ensure customers receive value for money, we are proposing to continue to seek external funding to leverage our funding contribution.

11.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 11.3 sets out our innovation expenditure proposal and governance arrangements, which have been agreed with the Customer Forum. This section also sets out the requirement for innovation funding, demonstrating why innovation projects are not funded under the existing regulatory framework;
- Section 11.4 outlines our engagement with customers to determine their views on the appropriate focus of the innovation projects, the innovation governance arrangements and demonstrating their willingness to pay;
- Section 11.5 describes our extensive negotiations with the Customer Forum, which has culminated in their support for the proposed program; and
- Section 11.6 provides information on our track record of success in delivering innovation and collaborating to do so. This provides strong confidence in our commitment to innovation and our ability to deliver.

11.3 Our innovation proposal agreed with the Customer Forum

This section of the proposal outlines our $7.5 million ($2021) innovation expenditure proposal and strong governance arrangements as agreed with the Customer Forum. This section of the proposal also explains why the innovation projects would not be funded under the existing regulatory framework.

11.3.1 Innovation expenditure proposal

As shown in Table 11-1 below, our final proposal for innovation involves expenditure of $7.5m ($2021) over the 2022-26 regulatory period. This consists of $1.2 million of opex and $6.3 million of capex which would fund nine strategic innovation projects that are expected to deliver significant customer benefits.

As agreed with the Customer Forum, the projects are all focused on unlocking the benefits of the energy system transformation that is underway and being driven by customers' strong take up of DER. DER[1] integration is complex and will evolve over time as more mature market arrangements develop for DER. DER network and market integration will ultimately involve a suite of solutions and technologies to provide efficient solutions for customers. The innovation program will contribute to finding and testing possible solutions.

The bill impact of the proposed innovation projects over the 2022-26 regulatory period is estimated to be:

- $0.95 ($2021) per annum per customer;
- $0.52 ($2021) per annum per residential customer; and
- $5.14 ($2021) per annum per non-residential customer.

1 As described by the Energy Security Board, DER are "resources located on the distribution system that generate, manage demand, or manage the network". This can include rooftop solar, battery storage, electric vehicles and vehicle to grid services, solar hot water, other generators, smart appliances such as air conditioners or pool pumps, energy efficiency, heat pumps, energy management systems such as microgrid controller and standalone power systems (SAPS). Source: ESB DER Integration Workplan, October 2019.

Table 11-1: Proposed innovation projects for the 2022-26 regulatory period ($2021 million)

	Innovation project	Capex	Opex	Total
	Low Voltage Projects			
1.	Efficient network balancing	$0.8	-	$0.8
2.	Supporting network voltages with new technologies	$0.6	$0.2	$0.8
3.	Supporting the network through partnering with DER customers	$1.1	-	$1.1
4.	Maximising the benefits of solar for commercial customers	-	$0.3	$0.3
	High Voltage Project			
5.	Day-ahead network management (or Predictive network management)	$0.7	-	$0.7
	DER Marketplace Projects (Network Management, Operations and Control)			
6.	DER management platform experimentation	$0.8	-	$0.8
7.	Testing the decentralised power system of the future	$1.0	$0.7	$1.7
	Data Availability Projects			
8.	Seamless and tailored DER connections	$0.5	-	$0.5
9.	Using our data sets to improve customer service	$0.8	-	$0.8
	TOTAL	**$6.3**	**$1.2**	**$7.5**

The innovation projects fall into four key groups:

1. **Low-Voltage**

   There are four low voltage initiatives that have the potential to transform our ability to accommodate DER – an outcome that we know from our customer engagement our customers support. These projects are seeking to develop new ways of managing low voltage (LV) networks by increasing the ability of LV networks to accommodate DER, while preserving quality of supply to other customers on the same local network. These initiatives involve solutions that can be implemented on either the network-side or the customer-side of the meter.

   All four of these initiatives have the potential to improve customer outcomes through better serving our customers and stakeholders.

2. **High-Voltage**

   A single high voltage-related innovation project is proposed to transform our ability to integrate DER – an outcome that we know from our customer engagement that our customers want.

3. **Network Management, Operations and Control**

   This portfolio contains two initiatives to develop, pilot and implement new technology and software to provide new operating capabilities for our system controllers. If successful, the initiatives will work in tandem to align the industry and empower customers to efficiently navigate their energy system. Customers will be able to efficiently manage their DER, thereby allowing them to benefit from their solar exports. The primary drivers for these new capabilities are:

   - to manage the operational challenges and inefficiencies that are emerging on the distribution network with increasing reverse flows of power; and
   - a lack of key information.

   We aim to take advantage of the capability introduced by DER to manage these adverse effects.

4. **Data Availability Program**

   The provision of accurate and timely information to customers is key to the efficient application of DER. We are already responding to new information requests from existing industry participants and new entrants, as DER use increases on our distribution network. At the moment, we can only address these queries manually – which is slow, error-prone and unscaleable. We expect DER use to continue to increase over the regulatory period and beyond which will result in higher volumes and new types of information requests, which cannot currently be answered quickly, accurately and at scale.

   This program contains two initiatives:

   - A specific automated tool that will fulfil connection requests from customers and third parties who want to install and use DER on unconstrained parts of the network; and
   - A generic tool that will allow us to develop new tools meet other types of information requests from customers and their agents quickly and accurately.

More detailed information on each project is provided in Appendix 11A to this proposal. This provides business cases that describe each project and explain how they meet the six criteria specified by the Customer Forum in order to gain their support. The Customer Forum's innovation project criteria are set out in Section 11.5 (below).

One of the criteria specified by the Customer Forum was that we should seek innovation partners for all projects. Letters of support from university-based collaboration partners are provided for the proposed Project 2 and Project 4 (provided in Appendix 11B to this proposal). The letters provide support for the projects and confirm their intention to collaborate with us on their delivery. Collaboration partners are also in the process of being confirmed for the remaining innovation projects.

11.3.2 Funding arrangements for the innovation projects

Key to the agreement that we have reached with the Customer Forum to support the innovation projects are the following proposed funding arrangements for the innovation projects:

- the innovation expenditure will only be available for the 2022-26 regulatory period. This means, for example, that the opex element would not become a permanent part of our base year opex;
- a 'use it or lose it' arrangement will apply, which means that we will return any funds that are not spent during the 2022-26 regulatory period to customers (at the end of the 2022-26 regulatory period). The 'use it or lose it' provision would apply to the total innovation allowance over the 5-year period, rather than operating on an annual basis, to allow smoothing of expenditure from year to year; and

- The Capital Expenditure Sharing Scheme and the Efficiency Benefit Sharing Scheme will not apply to the innovation expenditure.

11.3.3 Expected benefits of the innovation program

Our innovation plans are seeking to provide long-term benefits to all our customers by:

- more efficiently managing the growing amount of DER in our network; and
- allowing customers to maximise the value they can achieve from these investments, while also providing a benefit to all customers overall.

The dynamically managed network will also deliver detailed, real-time data to make better-informed network investment decisions and reduce long-term network costs for the benefit of all customers (including customers that do not invest in DER and customers beyond our network area).

Figure 11-1 (below) summarises the customer benefits that our innovation program will target. The expected benefits from our initiatives include reduced wholesale market costs, greater utilisation of available energy resources and improved customer choice. It is important to note that the innovation plans that we are proposing in many cases unlock these benefits for all customers, not just customers in our network.

Figure 11-1: Benefits from the proposed innovation program for all customers

To estimate the potential benefits of our innovation program we have analysed and estimated the long-term costs and benefits associated with the innovation projects and subsequent deployment of solutions and technologies. Benefits have been estimated using the comprehensive and robust cost benefit analysis undertaken for the Electricity Network Transformation Roadmap (ENTR).[2] To model the long-term benefits to 2050 we have:

- Mapped our suite of projects to the initiatives under the ENTR and identified the relevant ENTR benefits – the relevant ENTR benefits are approximately $16 billion in network savings to 2050 (in NPV terms).
- Allocated a proportion of the ENTR benefits to ourselves, using our share of customers and network, which is 6.5% of the Australian total. This apportions $1.04 billion of benefits to our projects.
- Apportion a share of the $1.04 billion of benefits to our individual innovation and DMIA projects based on the nature of the project and its likely effectiveness.

The initial innovation project and subsequent deployment costs across the 16 innovation projects and DMIA projects are estimated to be $443.4 million to 2050 (in NPV terms). The estimated benefits and costs result in a strong benefit-cost ratio of 2.3, meaning that there is a strong case to invest in the modest innovation program.

We have also estimated value associated with undertaking the proposed innovation projects in the 2022-26 regulatory period and not delaying these innovation projects to the following regulatory period (i.e.to 2027 to 2031). This analysis assumes a typical timing of value capture over the 50-year period based on a technology uptake "S" curve. The analysis shows that customers would lose:

- 24% of the total benefit if there is a 5-year deferral in the value capture; and
- 14% of the total benefit if there is a 3-year deferral in the value capture.

As recognised by the Customer Forum in their Engagement Report, the innovation projects are key to realising productivity improvements to more efficiently deliver electricity in two directions and respond to the broader energy system transformation.

Likely customer benefits of each proposed innovation project are listed in the table below.

Table 11-2: Potential customer benefits of the innovation projects

Project	Customer benefit
1. Efficient network balancing	Better power quality, less equipment damage for customers. Lower network cost. Unlocking more solar – allows customers to get the full benefit of their investment, more affordable electricity for all customers.
2. Supporting network voltages with new technologies	Better power quality, less equipment damage for customers. Lower network cost. Unlocking more solar – allows customers to get the full benefit of their investment, more affordable electricity for all customers.
3. Supporting the network through partnering with DER customers	This is focused on allowing more solar onto the network. Allows customers to get the full benefit of their investment. Makes electricity more affordable for all customers.

2 CSIRO and Energy Networks Australia 2017, Electricity Network Transformation Roadmap: Final Report.

Project	Customer benefit
4. Maximising the benefits of solar for commercial customers	This is focused on allowing more solar onto the network. Allows customers to get the full benefit of their investment. Makes electricity more affordable for all customers.
5. Day-ahead network management (or Predictive network management)	Allows more solar exports. Allows customers to get the full benefit of their investment. More affordable electricity for all customers.
6. DER management platform experimentation	A platform is necessary to support DER and new business models into the future - the industry are collaborating on this. Benefits are better services and more affordable electricity.
7. Testing the decentralised power system of the future	This is about innovating for the future where DER will be integrated into the wholesale market –innovating to design the systems, interfaces and working arrangements that will be needed. This seeks to allow better services for customer, making more use of the DER sitting on the network (less wastage) and making electricity more affordable.
8. Seamless and tailored DER connections	Better services for customers. Unlocking more solar – more affordable electricity for all customers.
9. Using our data sets to improve customer service	Access to data is necessary if better customer services are become a reality. More affordable electricity services. Better services for customers. Making more use of the DER sitting on the network (less wastage).

11.3.4 Governance arrangements

Our discussions with the Customer Forum and other stakeholders on the appropriate governance arrangement for the delivery of the innovation program was very useful and provided a clear understanding of customers' preferred governance model.

There was a strong preference that we adopt governance arrangements modelled on those developed by Ausgrid for their innovation program delivery that involve customers in the governance process.[3]

We have agreed to this. Our approach is slightly more streamlined than Ausgrid's, consistent with a prudent and efficient operator that is looking to manage a smaller portfolio of innovation initiatives in an agile manner (Ausgrid is managing a $42 million innovation program relative to our proposed $7.5 million program).

3 Ausgrid, Revised Regulatory Proposal, Revised Proposal, Attachment 3.02 Network Innovation Advisory Committee, Draft Terms of Reference, January 2019.

Although we will ensure that the cost of the arrangements will be kept in check, the governance arrangement will still deliver on the customer centric approach being sought to ensure that:

- customers are at the heart of the governance process (as is consistent with the New Reg approach);
- the projects maintain a focus on delivery of customer benefits; and
- collaboration and extensive sharing of all learnings is guaranteed.

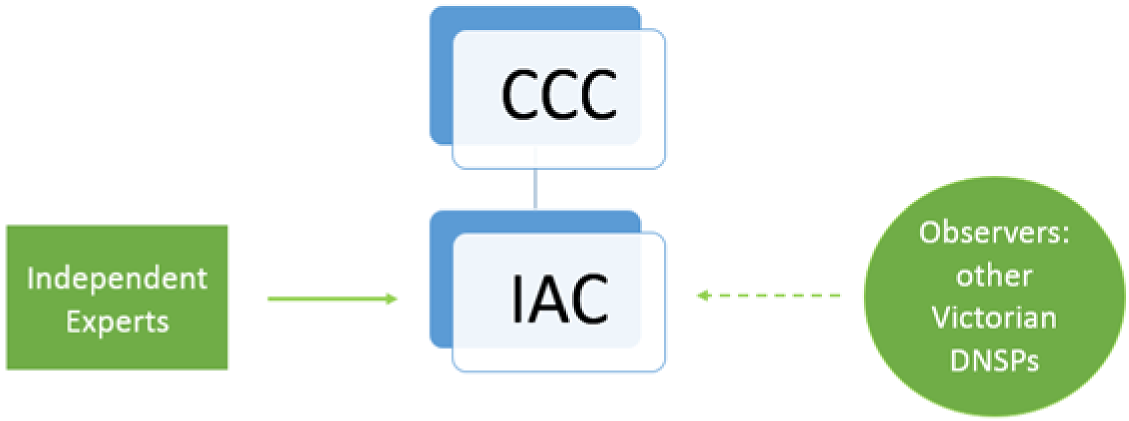
11.3.4.1 Innovation Advisory Committee

Our proposed approach to governance involves working with its CCC to establish an Innovation Advisory Committee (IAC), which will be a sub-committee of the CCC.

The IAC will be independent of AusNet Services and will evaluate and prioritise the innovation projects that it considers best reflects customer preferences. The purpose of the IAC is to represent customers and place the customer at the centre of investment decisions as we transform our network.

The proposed design for the IAC is shown in the figure below.

Figure 11-2: Innovation Advisory Committee (IAC)



Proposed membership

Membership of the IAC will be agreed between us and the CCC.

It is expected that the IAC will include customer and expert members (e.g. academics), as well as representatives from AusNet Services.

Customer representation is crucial given the evolving nature of innovation. The customer input will guide the future direction of expenditure. This will ensure innovation continues to be directed to achieving outcomes desired by customers.

The technical input will validate the rigour of projects and prevent duplication of effort across the industry.

The other Victorian Distribution Network Service Providers (DNSPs) have agreed to participate as observers. This is a great step forward and leaves scope for this relationship with the other Victorian DNSPs on delivery of innovation to deepen over time.

Establishment and meeting frequency

The IAC is to be formally constituted at the commencement of the next regulatory period.

The IAC will meet at least three times a year or as needed, at our offices. All correspondence within IAC meetings will be documented and minutes will be taken.

At its inception, the IAC will discuss the need for further governance arrangements such as a committee charter.

Confidentiality arrangements will be put in place at the IAC's commencement to ensure that members can be provided with confidential material as needed.

We will supply the IAC with information, business cases, decision documents, reports and other material that will allow it to perform its role.

Proposed functions

Excluding DMIA projects, the IAC will consider the innovation initiatives we have identified and will advise on which of those initiatives (to the value of $7.5 million over the 5-year regulatory period) should be prioritised.

IAC members are welcome to and may propose additional initiatives for our consideration. However, we will remain responsible for expenditure decisions.

We will validate approved innovation initiatives with technical and academic experts. This will be facilitated through our industry and research collaboration partnerships.

In the event that a planned innovation project were no longer needed (e.g. new findings made elsewhere or a new technological development), then the IAC could work with us to develop alternative innovation projects (only to the maximum value of $7.5 million in total over the 2022-26 regulatory period). These projects would need to meet the criteria set out by the Customer Forum and other stakeholders including that the projects:

- Seek to deliver benefits to customers;
- Are driven by customer needs and expectations;
- Can be understood by customers;
- Represent strategic innovation;
- Involve collaboration with other partners e.g. industry, academic, other;
- Customers are willing to pay; and
- The project would not be funded under the regulatory framework.

The IAC will ensure that we publish all innovation lessons and outcomes for each innovation project. There will be regular reporting as each project is delivered and at their conclusion.

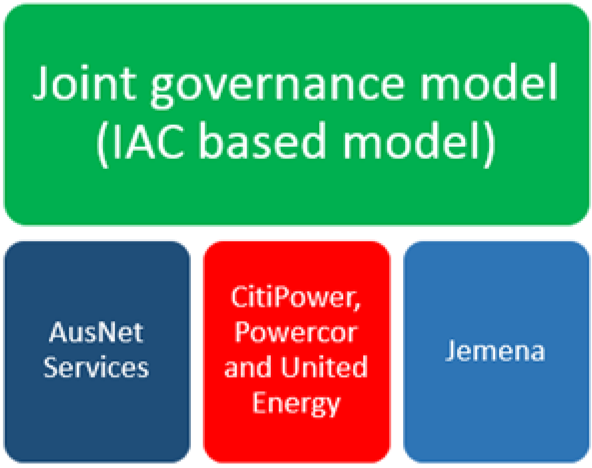
11.3.4.2 Working on closer industry collaboration

Recognising the potential benefits of collaboration we will continue to engage with other Victorian DNSPs on ways we can work together on innovation, including with respect to our innovation proposals and the IAC. Discussions held with the other Victorian DNSPs on the IAC to-date are positive, with in-principle agreement reached with the other Victorian DNSPs that they will participate in the IAC as a minimum as observers and potentially as sponsors of innovation initiatives based on the model we are proposing.

Having the other Victorian DNSPs involved in the IAC assessment process is a positive, albeit initial, step that will help minimise the scope for overlaps in innovation expenditure and which will facilitate collaboration and knowledge sharing – outcomes that will help maximise the potential customer benefit from each of our initiatives. This relationship is shown below.

We will continue to look for other ways that this industry collaboration relationship can develop. For example, there may be scope in the future for a joint innovation governance body (based on the IAC) that will have oversight of a significant innovation allowance from all the Victorian DNSPs. This potential evolution is shown in the figure below.

Figure 11-3: Possible evolution of innovation governance



While broader participation of this type is currently limited, this may change. And, the adoption of such an arrangement could result in:

- improved understanding of each businesses' knowledge base;
- a stronger focus on innovation; and
- a stronger focus on customers across Victoria.

Importantly, each business would still be responsible for developing their own projects and business cases, but the joint governance would prevent overlaps and maximise collaboration and knowledge sharing. While this is a hypothetical scenario, it highlights that we are considering these issues and we are committed to exploring options to ensure customers benefit from innovation over the long run.

11.3.5 Why specific innovation funding is required

The AEMC has recognised that the consequence of the changes taking place on our network is that the demands on the grid are fundamentally changing. As a result, there is an unprecedented need for network businesses to innovate, so that prudent and efficient solutions to the challenges ahead can be co-created with partners to develop the 'grid of the future'.[4]

The current regulatory framework does not reward innovation of the kind described by the AEMC.

Benefits beyond our customer base and over multiple periods not considered

The benefits of innovation extend to the entire market, not just our network, and to all customers. These wider benefits would not be considered in the economic case for standard network funding. In fact, the current framework actively discourages capex and/or opex that does not produce immediate benefits in terms of lower costs or improved reliability.

Innovation projects cannot be funded by the Demand Management Innovation Allowance

The default to date has been to fund innovation through the demand management innovation allowance (DMIA). We have allocated demand management projects to utilise the DMIA funding (of approximately $3.5 million) in the 2022-26 period that are separate to the innovation projects put forward in this proposal. Our innovation proposal seeks funding in addition to the DMIA amount.

[4] AEMC, Economic Regulatory Framework Review, July 2018.

This is because the innovation projects that we are proposing would not fit within the definition of demand management as they relate to supporting better outcomes for customers by transforming our network for the energy system changes that are already well under way.

The DMIA scheme has been successful in promoting innovation in relation to demand management solutions. In our view, there remains a strong case for increasing the DMIA, not least as we are one of the few DNSPs to have consistently fully utilised, over multiple periods, the DMIA (while also making the results publicly available).

At the time of our 2016-20 determination, some customer representatives strongly supported an increased DMIA. In particular, the Victorian Greenhouse Alliance supported our proposal for a $10 million allowance.[5] The Victorian Government also publicly supported early stage research and development (R&D) on demand management initiatives.[6]

At that time, however, the AER preferred to retain the current allowance, noting that the level of funding should be considered at an industry level, rather than for each business.[7] While this may be a reasonable approach where all DNSPS are fully utilising their DMIA allowance, where this is not the case, maintaining this position may not be in the best interests of consumers.

Expenditure incentive schemes would not fund the innovation projects

As the benefits of proposed innovation projects accrue over multiple regulatory periods, the expenditure incentive schemes are not capable of properly funding innovation - even though this expenditure is essential to transition the sector to lower cost and higher customer value outcomes.

Where the gap arises in relation to innovation and the EBSS is as follows. Successful innovation projects that result in efficiency savings (as opposed to service improvements) would deliver those savings in future regulatory periods, beyond the regulatory period in which the expenditure occurs. The efficiency saving would therefore be reflected in our expenditure forecast for the future periods and the expenditure allowances set by the AER. This removes the opportunity to outperform the allowance and hence fund innovation through the incentive payments.

Additionally, the Efficiency Benefit Sharing Scheme (EBSS) could impose a penalty on any additional expenditure to conduct a trial; and thereby act as a disincentive for innovation.

Impacts not sufficiently material for STPIS or the CSIS to apply

The only other incentive arrangement of any real relevance in terms of potentially funding our proposed innovation projects is the Service Target Performance Incentive Scheme (STPIS). This scheme is relevant as an aspect of some of the innovation projects relates to addressing the voltage issues that arise from the increasing penetration of DER and associated outages. However, the very small scale of the innovation projects, which will test particular solutions in very small scale settings mean that there can be no expectation of meaningful or material impacts on the service reliability outcomes that drive incentive payments under the STPIS (including improving the frequency and duration of outages).

We would draw the same conclusion in relation to potential funding from the CSIS. This is a small-scale incentive scheme and the outcomes of the innovation projects could only be expected to impact on one of the scheme parameters, namely the complaints parameter. To the extent that the innovation projects allow us to improve outcomes for customers regarding their DER and voltage issues on the network there may be future reductions in complaints.

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5 Victorian Greenhouse Alliances, Submission to the AER – Local Government Response to the Victorian Electricity Distribution Price Review (2016-20), July 2015, p. 26.

6 Department of Economic Development, Jobs, Transport & Resources, Submission to Victorian electricity distribution pricing review (2016-20), July 2015, p. 13.

7 AER, Final Decision, AusNet Services distribution determination, 2016 to 2020, Attachment 12 – Demand management incentive scheme, May 2016, p. 9.

The improvements in terms of reduced complaints would only be expected to arise in future regulatory periods and to the extent that the innovation projects are successful. The ability of the CSIS to provide any meaningful contribution is also severely constrained as the CSIS can only apply for a maximum of two regulatory periods.

The limitations on the scope of incentive schemes and the network innovation allowance gap have been highlighted elsewhere. For example, Australia's Chief Scientist, Dr Alan Finkel recently noted that there is a need for an electricity innovation framework that allows rapid proof-of-concept testing of new technologies and enables their accelerated integration into the competitive market.[8]

Dr Alan Finkel advocated that the rules, market frameworks and current processes need alignment to appropriately support emerging technologies and the ability for industry members to test them.

We are seeking funding for strategic innovation not operational innovation projects

Our proposed innovation program, which is directed at energy system transformation, is separate to the broader, more operationally based innovation that we fund and undertake to improve the efficiency, reliability and safety of distribution network services.[9] In the past these operational innovation funds have also been used to top up our contribution to DMIA-funded projects given the importance we attach to these projects.

Assessment of funding gap for each proposed innovation project

Specific information on the funding gaps relating to our nine proposed innovation projects is provided in the table below. The F-factor incentive scheme is not included in the funding mechanism listed below as it would not be applicable in terms of funding DER innovation projects.

Table 11-3: Innovation projects are not funded under the regulatory framework

EBSS/ CESS	DMIA	STPIS	GSLs	CSIS
Project 1: Efficient network balancing				
The way in which the incentive schemes operate mean that an efficiency reward would never be earned. If the innovation is successful it would be reflected in our forecasts of costs for future regulatory proposals, which would be lower than would have been the case without the innovation.	Not applicable as this is much broader than a simple demand management project.	Minor trial, not deployment – and hence cannot have a material impact on STPIS.	Minor trial, not deployment – and hence cannot have a material impact.	Minor trial, not deployment – and hence cannot have a material impact on complaints. The CSIS can also only apply for a maximum of two regulatory periods.

8 Dr Alan Finkel, Independent Review into the Future Security of the National Electricity Market, Blueprint for the Future, June 2017, p. 66.

9 Examples of recent projects that fit into this category include testing of drones, LiDAR technology and automated switching.

EBSS/ CESS	DMIA	STPIS	GSLs	CSIS
This is not recognised in the regulatory framework and hence would prevent efficiency benefits from being earned.				
Project 2: Supporting network voltages with new technologies				
As above.	Not applicable as this is much broader than a simple demand management project.	Minor trial, not deployment – and hence cannot have a material impact on STPIS.	Minor trial, not deployment – and hence cannot have a material impact.	Minor trial, not deployment – and hence cannot have a material impact on complaints. The CSIS can also only apply for a maximum of two regulatory periods.
Project 3: Supporting the network through partnering with DER customers				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	As above.
Project 4: Maximising the benefits of solar for commercial customers				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Not applicable.
Project 5: Day-ahead network management (or Predictive network management)t				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Minor trial, not deployment – and hence cannot have a material impact on complaints. The CSIS can also only apply for a maximum of two regulatory periods.
Project 6: DER management platform experimentation				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Not applicable.

EBSS/ CESS	DMIA	STPIS	GSLs	CSIS
Project 7: Testing the decentralised power system of the future				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Not applicable.
Project 8: Seamless and tailored DER connections				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Minor trial, not deployment – and hence cannot have a material impact on complaints. The CSIS can also only apply for a maximum of two regulatory periods.
Project 9: Using our data sets to improve customer services				
As above.	Not applicable as this is much broader than a simple demand management project.	Not applicable.	Not applicable.	Not applicable.

11.3.6 The National Electricity Rules (NER) allow for an innovation allowance

The AER has acknowledged that there are current gaps within the regulatory framework that should support innovation expenditure. We note that the National Electricity Objective (NEO) is:

> *…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> - *price, quality, safety and reliability and security of supply of electricity*
> - *the reliability, safety and security of the national electricity system.*

There is no explicit section within the NER that requires a full cost-benefit assessment of all proposed expenditure before it can be deemed efficient or in "the long-term interests of consumers" by the AER. The NER is also intrinsically linked to the NEO. The AER can approve all opex it considers to be in the long-term interests of consumers and our innovation program would be subject to governance arrangements that would ensure only those projects would proceed.

Where we are funded to undertake these strategic innovation projects, we will always continue to seek external funding to further leverage our proposed funding contribution.

11.4 Customer engagement and evidence of willingness to pay

We have undertaken extensive engagement and research to better understand our customers' preferences regarding the focus of innovation activities, innovation program governance and importantly, to determine willingness to pay.

In addition to our negotiation with the Customer Forum, the following broad customer and stakeholder engagement was undertaken:

- consultation on our Draft Proposal released in February 2019;
- a Deep Dive workshop with key customer advocates and stakeholders in May 2019; and
- a qualitative research study involving residential and small business customers in September 2019.

Consistent messages that we received throughout our engagement with all customers were that as long as DNSPs are not duplicating innovation initiatives and are sharing the knowledge gained from the innovation projects across the industry, then modest innovation funding by customers is supported.

Customers fundamentally understand the energy system transformation. Our research has consistently shown that our customers would like to adopt distributed energy and other behind-the-meter technologies and consider that innovation to meet future needs is appropriate (as discussed in Chapter 3 and 9). This research also shows a growing customer preference to have greater control over their energy use. It also shows that our customers' preferences are changing in a way that requires us to provide different services, through the application of technology and innovation.

Customers support modest innovation to prepare for, and assist, the energy system change – as long as tangible benefits for customers are delivered. There is greatest support for innovation activities that deliver benefits across the customer base and that benefit the wider community. The need to prepare for mass-market electric vehicle uptake is seen as a longer-term issue.

In terms of specific feedback received from customers:

- Most people support energy transformation innovation expenditure when positioned as $1 per household per year, and that support is greatest for projects that benefit a greater number of people.[10]
- There is agreement that there is a need to invest to cater for the future needs of customers and changing technologies. Several Local Councils and Community Groups stressed the need to build a smarter distribution network that can accommodate all the renewable technology that might connect to the network. These stakeholders saw this as being a critical consideration for us in the lead up to the 2022-26 regulatory period.
- Customer Focus Groups indicated that we 'should engage in more R&D activities around new energy technologies' to provide improved customer service. Enabling more solar exports, providing reliable supply for remote customers, addressing bushfire safety, and being prepared for emerging technologies are important propositions. Although it is not considered a core network activity, innovation with a long-term payoff is regarded as important in providing efficient and reliable services.

In summary, our customers are seeking to implement innovative energy solutions, and expect us to play a role in supporting them.

More information on the views expressed in the individual engagement processes are summarised below.

10 Ibid.

11.4.1 Draft proposal and Customer Forum Interim Engagement Report

Draft proposal (February 2019)

In the draft proposal we outlined that:

- during a period of transformation, innovation expenditure is required if customers are to benefit from the opportunities that this transformation brings;
- it had initially proposed innovation expenditure of $11.4m ($2020) for innovation. However, in negotiation with the Customer Forum this expenditure was reduced to $7.5m ($2020) – this is a level of expenditure around $2 per year per customer (and around $1 per year per residential customer). The lower level of expenditure partly reflected the Customer Forum's reluctance to fund projects to prepare for electric vehicle (EV) uptake. The Customer Forum view was that only a small number of customers are expected to adopt EVs over the next regulatory period.
- it was committed to publicly reporting on and sharing the outcomes of the innovation projects to avoid costly duplication across the sector.

Customer Forum Interim Engagement Report (Feb 2019)

In its interim engagement report the Customer Forum indicated that:

- customers are more likely to benefit from a modest and well targeted innovation program rather than no innovation expenditure;
- tangible short and medium term benefits are likely to arise from this expenditure; and
- the modest expenditure being proposed delivers value for money for customers.

In coming to this view, the Customer Forum expressed some concerns (which we have subsequently addressed) including that:

- It was not convinced the rationale for the expenditure was sufficiently connected to tangible and certain customer benefits but was rather more comfortable that innovation projects should have the potential to deliver a certain outcome for customers.
- Our initial list of projects lacked a consistent customer centric focus and that projects should seek to enhance customer experience.
- It was unclear how the initial $11.4m ($2020) had been determined and that using an approximate average of $2 per year for each customer or $7.5m ($2020) in total would provide a sufficient resource to undertake innovation work.
- The list of proposed projects should be refined based on the following principles:
    - Innovation projects/outcomes should directly benefit and result in improved service to customers;
    - Innovation needs to be driven by customer needs and expectations which should be identified through customer research. Customers will support innovation if they see the benefits;
    - The language surrounding innovation must be easy for customers to understand and offer a compelling potential benefit;
    - Innovation needs to be strategic and should include an evaluation;
    - All initiatives to be published on our website and shared with industry; and
    - Projects must show evidence of collaboration with retailers and other distribution businesses and/or retailers.
- Proposed projects should only proceed where we can link the potential customer benefits to customer and stakeholder expectations.

- Progress of innovation projects need to be published to ensure customers have confidence that this investment is aligned with customer needs and expectations (although it also noted that we had agreed that innovation learnings would be shared with other DNSPs).

11.4.2 Stakeholder feedback on Draft Proposal

The views summarised below reflect stakeholders' views on our draft proposal.

AER staff

AER staff noted the divergence of opinion between the Customer Forum and us on innovation expenditure ($11.4m ($2020) versus $7.5m ($2020)) and the issues it considered important for future negotiations. Specifically, it noted:

- That it was unclear how an allowance that was not linked to a specific activity or objective could be demonstrated to be prudent and efficient. However, the AER explained that it could approve step changes for specific innovation projects and programs.
- How the AER assess step changes, and the evidence it requires to support a step change, including evidence of customer support.
- There appeared to be confusion as to whether or not the Customer Forum supported the innovation proposal (and what conditions needed to apply).
- There are potentially several mechanisms through which we could look to recover innovation expenditure and this meant that this funding proposal may not be necessary.
- We could apply for grants for innovation projects from agencies such as the Australian Renewable Energy Agency (ARENA).

Consumer Challenge Panel (CCP) Sub-Panel CCP17

The CCP17 supported effective, targeted innovation by network businesses, where this can deliver meaningful benefits to customers. It considered that the Customer Forum's approach to estimating the innovation allowance for a network business had merit if it is then applied as an expenditure cap. However, it also noted it would still expect to see business cases developed for each individual project, with a heavy weighting placed on the realisable benefits to customers.

Other issues/concerns that it raised were:

- Why we were best placed to undertake this innovation and why some of this research could not be undertaken by other businesses or jointly;
- What other funding sources for these projects are available/have been considered;
- The lack of clarity around how the proposed innovation expenditure will be captured in our regulatory proposal. Specifically, it asked if this expenditure was already included in the opex base year;
- What role customers will have and suggested that the governance arrangements recently adopted by Ausgrid i.e. the Network Innovation Advisory Committee may be appropriate;
- What actions do we intend to take to mitigate the impact of EVs on the our network over the next regulatory period, while noting that:
    - the Customer Forum cites customer research indicating that customers do not believe this is important; and
    - this was a matter for further analysis and discussion leading up to lodgement of our proposal.

Energy Users Association of Australia (EUAA)

The EUAA noted that the projects proposed need to reflect true innovation. This involves contributing significantly to existing knowledge, instead of repeating or testing a variant that has previously been undertaken.

Eastern Alliance for Greenhouse Action (EAGA)

The EAGA supported the $7.5 million innovation allowance, particularly the specific programs that involve collaboration with local government bodies.

Energy Consumers Australia (ECA)

The ECA questioned the classification of some of the initiatives within our portfolio as to whether they could be classified as core business rather than true innovation. It stressed that other businesses have used similar innovation allowances on initiatives that have not been previously tested. The ECA is concerned that consumers do not pay for similar projects and that they accrue actual benefits.

11.4.3 Innovation deep dive workshop

On 23 May 2019, we held a deep dive workshop to explore its innovation proposal. A range of issues were discussed at that workshop and this is summarised below.

Approach to innovation

Most attendees supported the need for innovation and for us to innovate. However, some issues were raised, including:

- The need for networks to respond to the rapid transformation in the sector and to more clearly communicate the benefits to (all) customers of innovation related activities.
- Perceptions of insufficient collaboration and knowledge sharing amongst electricity network businesses regarding innovation.
- The importance of clearly communicating and demonstrating the pathway from innovation to business as usual.
- The appropriateness of the current regulatory framework to supporting innovation and whether there needs to be a broader industry-level mechanism to fund longer-term network innovations.
- The extent that customers should pay for innovation that would otherwise not have been undertaken.

Our proposed innovation portfolio

- There was interest in our innovation portfolio but the need for the following was highlighted:
    - a strong narrative explaining why an initiative is important;
    - information on how any initiative leverages or extends prior studies and trials (and the importance of ensuring that this occurs);
    - clearer communication on the expected benefits for customers relative to the business; and
    - an explanation as to why innovation funding is required and why it is not already funded e.g. by other incentive schemes.
- Some participants highlighted the need for system wide/network innovations as opposed to solving isolated issues at a time.
- There was a lack of support for the inclusion of customer experience initiatives within the innovation program

- Advocates stressed the importance of articulating broad benefits to customers and making them aware of the effect of insufficient innovation will result in.
- There was support for testing grid sensing and dynamic hosting of DER. However, some participants highlighted the importance of knowing 'what is happening in the transmission network'.
- The need to better define the gap between the base level of service and any proposed innovation, and why that innovation is important and how it will benefit customers. It was also noted that in the absence of these criteria being met, 'innovation' initiatives are often just business as usual.
- Some participants highlighted that further innovation on the integration of EVs was important and should occur now (and not to wait for subsequent regulatory periods).
- Innovation should not just be thought of as technical – there should be scope to focus on areas such as tariff reforms and market reform related innovation.

Innovation and governance

Participants highlighted the importance of strong governance to ensure appropriate customer input and benefit. However, a range of other concerns were identified:

- The potential appropriateness of Ausgrid's governance approach for innovation – could provide an appropriate forum to discuss technical issues and a filter process to give customers confidence that a business case for innovation had been tested.
- Various other issues associated with the potential establishment and operation of an Ausgrid-like governance approach, including:
    - The ability to establish a new sub-committee of the CCC with the requisite skills and capabilities to focus on these technical related issues;
    - The need to ensure there was sufficient 'actual customer' representation on the CCC, including non-metro customer representation, and the need to ensure there is scope for other customers to provide input and express and opinion in key decision making meetings;
    - The need to be flexible when establishing any forum to maximise the scope for those involved to contribute; and
    - A need for transparency, including with respect to membership and the publishing of meeting minutes.

11.4.4 September 2019 Customer research

JWS Research undertook qualitative customer research[11] to test whether customers valued our proposed innovation projects and their willingness to pay for $7.5 million worth of projects with a bill impact of $2 per year across all customers or $1 per year for residential customers. The innovation projects were presented in three groupings:

1. Unlocking the potential of the network to support new customer needs e.g. solar exports and energy trading;
2. Improving remote supply and addressing bushfire safety using stand-alone power systems; and
3. Preparing for the impact of EVs.

This research involved:

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[11] JWS Research, Community Perceptions Toward Solar and Innovation Propositions, September 2019.

- Two face to face focus groups in an outer metropolitan area of our network, with 6 to 8 participants in each group, one group under 54 years old, one group 55 years and older;
- A residential online group from across our network (metropolitan and regional) with 15 to 17 participants; and
- A small business online group from across our network (metropolitan and regional) with 15 to 17 participants.

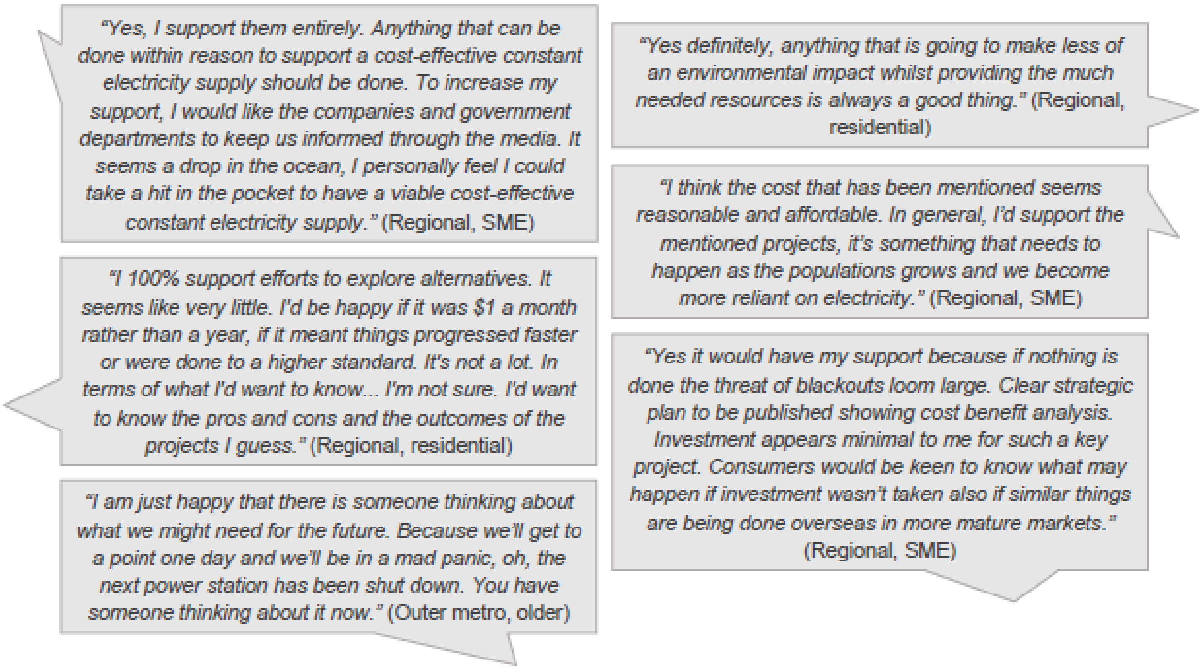
Overall, there was support for customer funding of the three project areas up to $7.5 million.

Although all project groupings were supported, the first set of projects to unlock the network potential is perceived by customers to have the great benefits for the most people and hence was chosen by many as the preferred option.

Customers were interested in more information on expected benefits or outcomes and a specific timeline so that we would be accountable.

Verbatim comments on the innovation projects from the customers that are supportive of investment in innovation are also shown below.

Figure 11-4: Select verbatim comments supporting innovation projects



A copy of the full JWS Research report is provided in Appendix 3E.

11.4.5 Engagement with local communities on the energy future

In addition to the feedback we received from our customer research, changing customer preferences is evident by the number of local communities that have approached us about renewable energy projects, including:

- Totally Renewable Yackandandah project;
- Healesville Community Renewable Energy Project;
- Totally Renewable Beechworth;
- Renewable Albury Wodonga;
- Sustainable Seymour;
- Mirboo North Community Energy Hub;

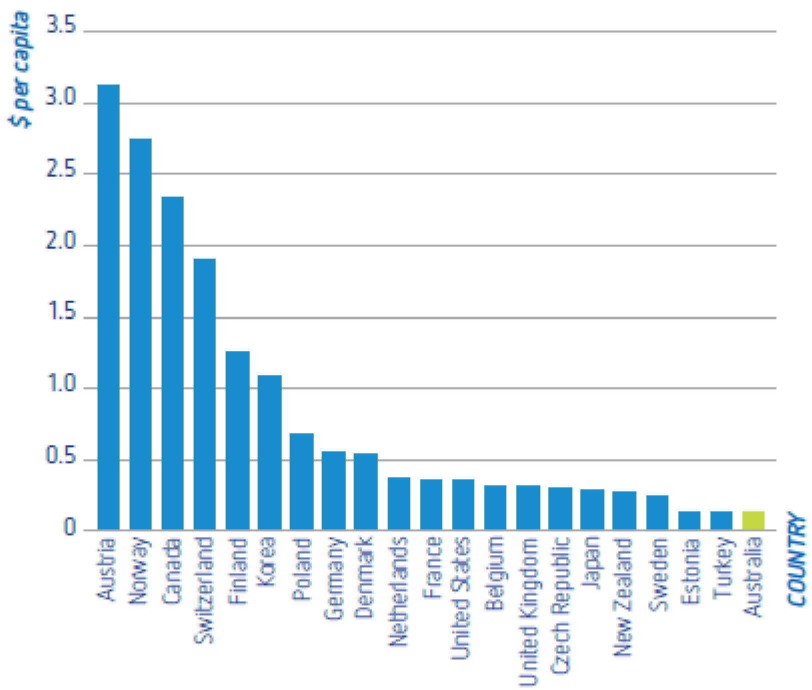
- Totally Renewable Phillip Island;
- Sustainable Sale: and
- Mallacoota Sustainable Energy Group.

11.5 Customer Forum negotiation culminating in support for the innovation proposal

Significant consultation with customers and other stakeholders has been undertaken and has underpinned a lengthy and robust negotiation with the Customer Forum on the merits of our innovation proposal. Early in the negotiation, the Customer Forum concluded that customers would support innovation if there were direct benefits for them, including improved productivity and enhanced customer experience, such as better outage management.

We explained that Australia is investing much less in network R&D than other countries, as shown in Figure 11-5. Both the AEMC and the Independent Review into the Future Security of the National Electricity Market, Blueprint for the Future (the Finkel review) have noted that this situation is not sustainable.

Figure 11-5: Network R&D funding per capita 2014



Source: IEA and United Nations database, Electricity transmission and distribution RD&D funding per capita, USD (2015 prices and PPP), 2014.

11.5.1 Customer Forum supports the proposed innovation expenditure

The Customer Forum supports the proposed $7.5 million innovation allowance.

In order to achieve support from the Customer Forum we have made the following enhancements to the innovation proposal over the course of the negotiation process with the Customer Forum:

- Reduced the innovation funding sought from an initial $11.4 million to $7.5 million ($2021). The Customer Forum initially concluded that we should construct an innovation budget on a modest contribution of approximately $2 per year for each customer or approximately $1 per year per residential customer. It therefore proposed that our original suggestion of $11.4 million over the 5-year period be reduced to $7.5 million ($2021). We have agreed to this reduction of the proposed innovation expenditure;

- Removed specific projects at the Customer Forum's request, including projects to prepare for Electric Vehicles and projects to test the economics of Standalone Power System in remote parts of our network;
- Reprioritised remaining projects against the criteria set by the Customer Forum and to align with the value that customer's see in supporting energy system transformation;
- Committed to implementing stringent, customer-focussed governance arrangements to agree to the delivery of the innovation projects, to provide strengthened coordination across the Victorian distribution business and to ensure that innovation project outcomes and learnings are shared across the industry;
- We have agreed that that the innovation expenditure will only be available for the 2022-26 regulatory period and, as a result, it will not become a permanent part of base year opex. The incentive schemes will not apply (EBSS/CESS), and any funds not spent will be returned in full to customers at the end of the 2022-26 regulatory period.; and
- Revised the projects' descriptions to better articulate customer benefits offered.

11.5.2 Seeking alternative sources of funding

Grants provided by ARENA are an additional means of securing innovation project funding. We have a strong track record of accessing ARENA grants and other sources of funding to offset the costs of network innovation projects to our customers. The Customer Forum sought clarification on whether we were applying for an appropriate amount of ARENA funding when compared to other DNSPs and hence not only relying on customer funding for our innovation projects.

We maintain strong links and open communication with ARENA, including through participation in ARENA's incubation and acceleration workshops and the joint ARENA/AEMC Distributed Energy Integration Program (DEIP) Dive workshops that are used for setting the priorities for ARENA funding.

When measuring ARENA's funding of past and current distribution business innovation projects, we receive the second highest level of funding among the other DNSPs in the National Electricity Market (NEM) at close to $4 million, behind United Energy at approximately $8 million. To put this in context, there are only four other DNSPs that have received ARENA funding (Jemena - $1.1m; Powercor - $0.4m; Actew AGL - $0.6m; and TasNetworks - $0.5m). This reveals that:

- the Victorian DNSPs are some of the most active in the NEM in terms of pursuing and collaborating on innovation;
- we have managed to capture significant funding through our applications to ARENA and collaboration with innovation partners; and
- seven other DNSPs within the NEM have not been successful to date in receiving ARENA funding.

We have agreed with the Customer Forum that we will continue to seek external funding, including from ARENA, to leverage our funding of innovation projects.

11.5.3 Customer Forum review of proposed innovation projects

Having accepted the case for an innovation allowance, the Customer Forum negotiated the amount of innovation funding that it considers should be allowed by the AER and the conditions that should be attached to it. As part of its consideration, the Customer Forum undertook a detailed review of our proposed innovation projects.

The Customer Forum requested that we provide a refined list of innovation projects based on the following principles:

- innovation projects and outcomes should directly benefit and result in improved service to customers;

- innovation must be driven by customer needs and expectations, which should be identified through customer research. Customers will support innovation if they see the benefits;
- the language surrounding innovation must be easy for customers to understand and offer a compelling potential benefit;
- innovation needs to be strategic and should include an evaluation;
- information on all innovation initiatives should be published on our website and shared with industry; and
- projects must show evidence of collaboration with retailers and other distribution businesses and/or retailers.

Following further engagement with customers, the Customer Forum concluded that:

- the proposed innovation expenditure should only proceed if we are able to link the potential customer benefits to customer and stakeholder expectations; and
- information on the progress of innovation funded by customers should be published to provide confidence that any proposed expenditure is aligned with their needs and expectations, consistent with past practice.

We have fully accepted the Customer Forum's conclusions and recommendations and have:

- refined our proposed innovation projects to focus more clearly on customer benefits;
- provided details on how we intend to collaborate to maximise the value from our expenditure and avoid costly duplication of effort across the industry for each project; and
- proposed governance arrangements that enable customers to direct the innovation expenditure, supported by independent experts.

As a result, the Customer Forum has provided their support for the proposed innovation projects.

11.6 AusNet Services' strong innovation and collaboration track record

The section provides information on our track record of success in delivering innovation and collaborating to do so. This provides strong confidence in our commitment to innovation and our ability to deliver.

The Australian electricity sector has a long-standing culture of collaboration on research and development. For example, the ENA engages, challenges and collaborates with governments, policymakers and the wider community on a range of issues affecting Australian energy networks. This includes innovation, where Energy Networks Australia (ENA) is partnering with leaders in innovation and technology to address the challenges facing the industry.

As a member of ENA, we help shape ENA policy through ongoing engagement, including participation in industry workshops and submission preparation. We also contribute to, and have access to, the ENA's online knowledge sharing platform (library), known as Knowledge Bank. This library contains useful research papers, customer benefit analysis and other relevant information. We use the information contained within the online knowledge sharing platform (as do our peers) to access and consider information that has the scope to help us undertake innovative work, including preparing proposals.

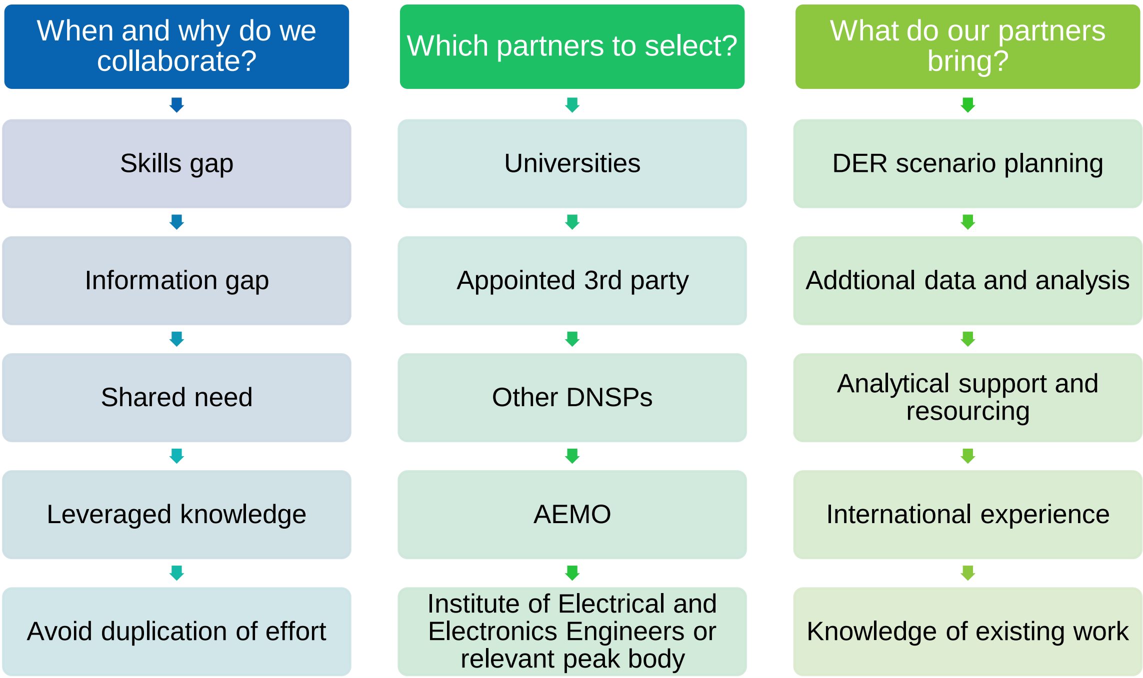
11.6.1 Collaboration on innovation

Our innovation proposal builds on our award-winning track record in delivering innovation and emphasises collaboration. We will continue to look for opportunities to collaborate on all our initiatives as we recognise this will minimise costs, facilitate knowledge sharing and reduce scope for duplication – outcomes which maximises the potential for customer benefits to be realised.

We have sought and gained in-principle agreement from the other Victorian DNSPs to work with us on our proposed governance arrangements for innovation, consistent with this philosophy of collaboration. We are continuing to encourage all Victorian DNSPs to formally join with us in nominating a portfolio of initiatives to be governed by a joint innovation process to maximise the impact of any spend across Victoria. This is an important step to ensuring as many customers as possible can benefit from a more coordinated approach to innovation for the energy system transformation in Victoria.

For our part, we have established strong collaborative partnerships with a wide range of organisations and continue to look for ways we can work with others.[12] The choice of partners to assist with a particular project will vary depending on the particular challenges and the 'gaps' in our expertise. Figure 11-6 illustrates the drivers for collaboration and the partners that currently work with and support us.

Figure 11-6: Drivers and partners of collaboration



Using the above approach, we have established a strong and credible record of accomplishment of collaborating with our peers and the broader community to deliver best value expenditure. For example:

- In 2017, the *Mooroolbark Mini Grid* Project was named joint winner of the Clean Energy Council's Innovation Award. Working with our partners, GreenSync and PowerTech, the project provides insights about how the network should be configured for the benefit of all our customers in the face of a rapidly changing energy landscape.
- In 2019, the *Networks Renewed* Project – a collaborative partnership between AusNet Services, Essential Energy and the Institute for Sustainable Futures at the University Technology Sydney – was the winner of the Innovation Award at the Clean Energy Council Awards.[13] The project was partly funded by ARENA and the success has resulted in broader benefits to Australia, including greater opportunities for residential solar customers.

These trials illustrate the strength of our collaboration with industry partners and the community. The table below provides further information on some of our award-winning projects where collaboration has delivered significant benefits.

[12] We have established partnerships with (amongst others) Deakin University, the Royal Automobile Club of Victoria (RACV) and the Australian Renewable Energy Agency (ARENA).

[13] See: https://www.cleanenergysummit.com.au/page/1403259/awards (accessed 15 August 2019).

Table 11-4: Collaborative projects undertaken to date

Projects	Project scope and partners
Networks Renewed (Advancing renewables program)	• Project sought to increase the amount of renewable energy in Australia via innovative use of mass distributed solar and storage • Partnered with University of Technology Sydney (UTS), Mondo Power, Essential Energy and Totally Renewable Yackandandah (TRY) community group • Delivered presentations to community participants for project updates • Site visits for ARENA and TRY • 2019 Winner of Innovation Award by Clean Energy Council
Mooroolbark Mini Grid	• We ran three different scenarios regarding solar impact management in an established community to test how a mini grid would interact with the rest of the network • Partnered with local emerging energy businesses GreenSync and PowerTech • Delivered presentations at seminars from Australian Institute of Energy, Electric Energy Supply Association, Energy Networks Australia, The Commonwealth Scientific and Industrial Research Organisation (CSIRO), Australian Utility Week, Department of Environment, Land, Water and Planning (DELWP), Australian Energy Market Commission (AEMC) and Downstream NZ • Site visits to Horizon Power, State Grid JU, AER, Essential Services Commission (ESC) and Monash University • 2017 Winner of Innovation Award by Clean Energy Council
Grid Energy Storage System (GESS)	• Australian first trial of a large-scale battery storage system that collaborated around network support from third-party proposals including ABB Australia and Samsung SDI • Partnered with Deakin University • Delivered presentations to Clean Energy Council, All Energy, National Electricity Market Future Forum
Residential Battery Storage Trial	• Investigate potential of residential battery storage and solar generation and the subsequent effects on demand, the network and customers • Partnered with local supplier M-Power and EnergyAustralia • Delivered presentations to ENA and Future Networks Webinar forum
Mallacoota Sustainable Energy Study	• Investigation in non-network alternative electricity supplies to the Mallacoota community • Partnered with community group Mallacoota Sustainable Energy Group, East Gippsland Shire Council and consultant Enhar • Delivered synopsis report for general public consultation

Projects	Project scope and partners
GoodGrid (formerly Peak Partners)	• Residential demand management test focused on behavioural response and air conditioning load control • Partnered with start-up technology provider energyOS • Partnered with RACV, and local school communities

11.6.2 Accessing external funding

We have been successful in securing some external funding from ARENA (the main source of funds for energy system transformation projects) and will continue to do so while this is available.

We have a strong track record of accessing ARENA funding and other sources of funding to offset the costs of network innovation projects. We have several externally funded projects and opportunities in various stages of development, which are listed below.

Completed:

- Networks Renewed - ARENA: In this project we partnered with the University of Technology Sydney, Essential Energy, Mondo and the Yackandandah community to build and test the concept of remotely managing the reactive power component of customer solar and battery inverters to help manage network voltages and therefore allow more solar to connect to the network. This was a national-leading project and category winner in the 2019 Clean Energy Awards hosted by the Clean Energy Council.

Currently underway:

- Creating solar-friendly Neighbourhoods – ARENA: In this project we are partnering with Jemena the University of New South Wales to prove the concept of dynamically balancing phase voltages using new technologies, with the aim of improving power quality and allowing more solar to connect to the network.
- Euroa Microgrid – DEWLP: In this project we are partnering with Mondo to test the network impact and functions available from a cluster of controllable DER across the township of Euroa
- Advanced Planning of PV-Rich Distribution Networks - ARENA: We are partnering with University of Melbourne to undertake modelling of distribution networks with a high penetration of DER and identifying ways to assess the capacity of the network to host additional DER at any point in time.
- LV Feeder Taxonomy – ARENA: We are providing data to support this CSIRO project that is seeking to build representative models of distribution networks across Australia.
- Latrobe Valley Microgrid - ARENA: We are also the host network for the ARENA funded Latrobe Valley Microgrid (LTVM), a trial designed to test the feasibility of a local energy marketplace that hopes to save money for participants and increase generation from renewable energy sources in the Latrobe Valley. Led by Brooklyn-based LO3 Energy, the study will focus on how to create a local marketplace out of around 200 dairy farms in the Latrobe Valley. We have provided $200,000 of in kind technical support for the project.

Proposed:

- DER Marketplace - ARENA: Working with AEMO, Mondo and the University of Melbourne, this is proposed to be a nationally important project that aims to build and test in practice the hybrid DSO model as proposed under the joint AEMO/ENA Open Energy Networks process. This is a model of the future power system where the dispatch of energy resources by AEMO will include a large amount of DER, and therefore require that this dispatch is coordinated closely with the operational state and available capacity of the distribution network.

- Flexible PV exports - ARENA: We are currently in discussions with SA Power Networks and several DER equipment vendors regarding an ARENA proposal to trial the concept of flexible PV exports as a means of increasing the number of solar customers that we can connect to the network.
- EV Charging management - ARENA: We have been invited by ARENA to submit projects, and are currently in discussions with several other networks and charging management providers to form collaborations and design a proposed project looking into the value (for both network and customer) and customer experience of managed EV charging.
- 100% solar housing estates: We are in discussions with a housing developer about a potential project that would design and implement solutions to allow a housing estate to have 100% solar penetration whilst minimising costs and maintaining power quality to customers. This would include a review of external funding opportunities.

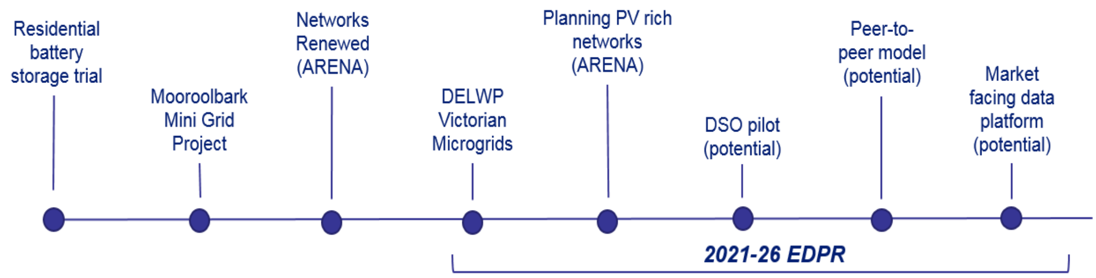
We also maintains strong links and open communication with ARENA, including through participation in ARENA's incubation and acceleration workshops and the joint ARENA/AEMC Distributed Energy Integration Program (DEIP) workshops that are used to set the priorities for ARENA funding.

11.6.3 Collaboration with industry and academia and knowledge sharing

We have also worked closely with industry and academia on first-of-a-kind projects, and accordingly leverage the knowledge gained from this experience with others. The knowledge that we garner from our work, including from innovation projects, is reflected in the ongoing contributions we make to the sector. We are an active working member of many industry and market-wide working groups on innovation projects.

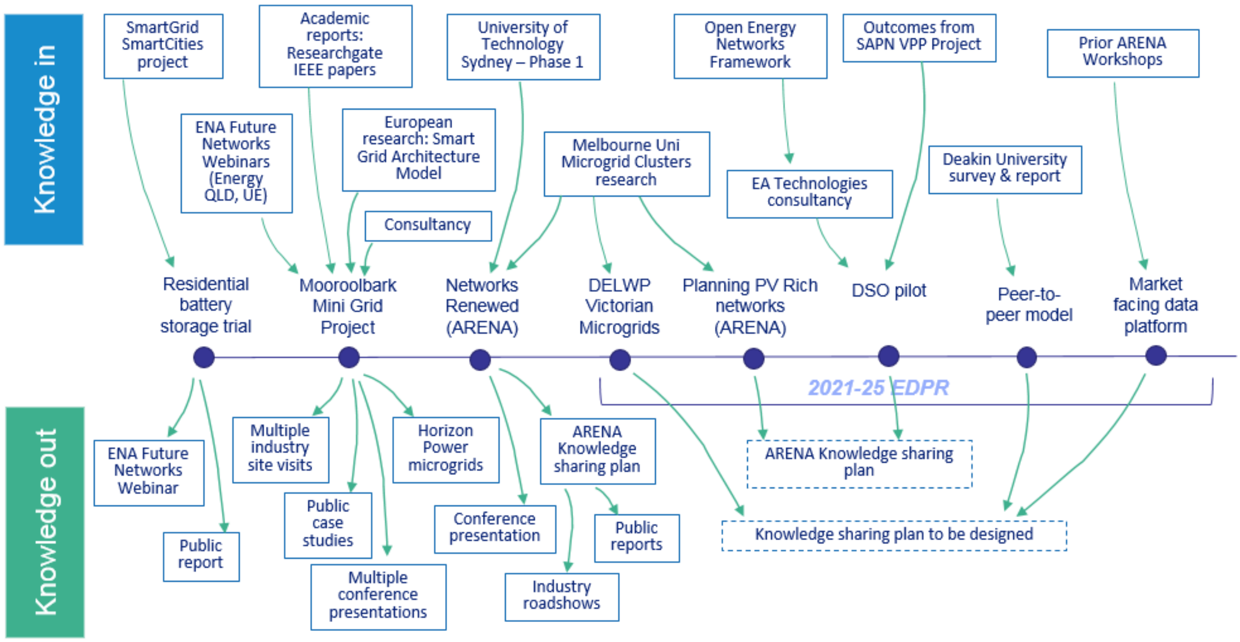
For example, Figure 11-7 and Figure 11-8 (below) show how we collaborated in our journey towards seamless DER integration and how we shared our knowledge through that journey.

Figure 11-7: Collaboration with industry and academia on customer DER



Key partners	mpower	GreenSync, Power Technology, Monash University	University of Technology Sydney, mondo, Totally Renewable Yackandandah	**Euroa Environment Group**, mondo	The University of Melbourne	Potentially The University of Melbourne, AEMO, mondo	Potentially: Powershop, Alternate Energy Innovations	To be determined
What are we testing?	**Hardware tech** How do batteries work and what impact/benefit do they have?	**Control** Can a cloud-based control interface coordinate a fleet of customer DER	**Customer use case** Can we use controls to enable more solar to connect?	**Suite of services** What range of network services can a microgrid deliver?	**Advanced analytics** How do we know how much solar the local network can host.	**Integrated market** Can DER be coordinated across wholesale, DNSP and cust?	**Future markets** How can Peer-to-peer energy flows be harnessed to benefit cust and network?	**Open enablement** What is the value to customers of opening up network data?
What is unique, or industry first?	Network-focussed residential battery trial under DMIA	100% fully inverter based microgrid in an existing network area	Dynamic control of reactive power from customer solar	Community focussed microgrids delivering local optimisation	New analytical technique using smart meter data	Puts into practice leading thinking within industry	Unique business model that can work within Regulations	Still only a concept within industry but potential large benefits

Figure 11-8: Sharing of knowledge throughout or DER innovation journey



11.7 Supporting documentation

The following documents are provided in support of this chapter:

- Appendix 11A – Innovation Business Cases; and
- Appendix 11B – Letters of support from innovation project collaborators.

12 Regulated Asset Base

12.1 Key points

The Regulatory Asset Base (RAB) has been calculated in accordance with the Rules provisions and the AER's Roll Forward Model (RFM) and Post Tax Revenue Model (version 4) (PTRM).

Our opening RAB for the forthcoming regulatory period includes a transfer of secondary system assets from existing asset classes to a new asset class 'Secondary systems – pre 2016' including recalculated remaining lives.

12.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 12.3 discusses our past capital expenditure;
- Section 12.4 explains the methodology for rolling forward the asset base values to 1 July 2021;
- Section 12.5 outlines our proposed Final Year asset adjustments included in the roll forward model;
- Section 12.6 outlines our response to a number of suggested changes in the roll forward model and PTRM as part of the AER's pre-lodgement engagement;
- Section 12.7 explains the derivation of the RAB values for each year of the next regulatory period (2021-22 to 2025-26); and
- Section 12.8 lists the relevant supporting documents for this chapter.

12.3 Review of past capital expenditure

Clauses S6.2.2A of the Rules permits the AER to review past capital expenditure (capex) in certain circumstances, and exclude capex from the RAB where actual total expenditure over the review period exceeds the AER's allowance (adjusted for contingent projects and approved pass through amounts), and that capex is deemed inefficient or imprudent. For the purpose of such a review, the relevant review period is 1 January 2014 to 31 December 2018. [1]

We have not overspent against our approved capex allowance during the review period and, as such, there is no basis for the AER to exclude capex from the RAB.[2]

Accordingly, all the capex we incurred during the current regulatory period will be included in the regulatory asset base.

12.4 Establishing the opening RAB as at 1 July 2021

Our opening RAB has been calculated in accordance with the AER's standard regulatory approach.

In April 2019, the Minister for Energy advised us that the Victorian Government intended to pass legislation to extend the current regulatory period by six months. As a consequence, we are required to roll forward both the RAB and Tax Asset Base (TAB) by a further six months to 30 June 2021.

1 NER, clause S6.2.2A(a1).

2 Neither of the other two requirements that allow the AER to make a determination that a DNSP's past capex is inefficient (the margin requirement and the capitalisation requirement) have been satisfied: clause S6.2.2A(b).

To achieve this, we have used a modified version of the AER's standard Distribution RFM model and extended this by six months. Forecast inputs for WACC and inflation were used and are consistent with those values entered in the 6 month PTRM. For capex, the RAB has been rolled forward based on a bottom up forecast of expected capex.

As the actual capital expenditure for the final two and a half years of the current period (2019, 2020 and 6 months to 30 June 2021) is not yet known, our opening RAB estimate in this proposal reflects forecast information. The Revised Regulatory Proposal will take account of the actual data for 2019, but not 2020. An adjustment to the forecast information will need be made in the subsequent regulatory review. Similarly, the opening RAB for 1 January 2021 includes a correction to incorporate actual information from 2015.

The opening RAB for 1 January 2021 also includes several final year asset adjustments as reflected in our Proposal RAB roll forward model. These particular adjustments are explained in further detail below in section 12.5.

The calculation of the opening RAB for 2021 therefore involves the following standard steps:

- Adopt the approved opening RAB as at 1 January 2016;
- Add actual and forecast capital expenditure (net of disposals) for the period 2016-2021;
- Deduct the annual nominal depreciation forecast for the 2016-2021 period;
- Add the RAB indexation amount for the 2016-2021 period;
- Make an adjustment to correct for the difference between actual and forecast net capital expenditure in 2015; and
- Reflect the forecast final year asset adjustments in the roll forward model, which are explained in section 12.5.

The table below sets out the RAB roll forward calculation for the current period.

Table 12-1: Regulatory Asset Base roll forward to 1 July 2021 ($m nominal)

Regulatory Year	2016	2017	2018	2019	2020	2021 (first 6 months)
Opening RAB (1 January)	3,442.1	3,610.5	3,809.4	4,067.7	4,363.2	4,636.4
Plus Capex, net of disposals and contributions	298.7	332.6	367.4	404.0	411.9	188.5
Less Nominal Forecast Straight-line Depreciation	-182.3	-170.6	-182.8	-193.0	-208.2	-105.8
Plus Nominal Actual inflation on opening RAB	52.0	36.9	73.7	84.5	69.5	46.1
Difference between Actual and Forecast Capex for 2015						-38.4
Forgone return on difference						-11.7
Final Year Asset Adjustments						0
Closing RAB (31 December)	**3,610.5**	**3,809.4**	**4,067.7**	**4,363.2**	**4,636.4**	**4,715.1**

Source: AusNet Services Roll Forward Model (2016-21).

In accordance with the above calculation, our proposed opening RAB for 1 July 2021 is $4,715 million (nominal). As already noted, our opening RAB will be updated in our Revised Regulatory Proposal to reflect actual data for 2019.

12.4.1 Actual and forecast net capex, 1 January 2016 to 30 June 2021

The RAB roll forward calculation requires a combination of actual and forecast capital expenditure (net of contributions and disposals), as shown in Table 12-2 below. Actual costs and disposals information reconcile with the nominal values reported in the Annual Regulatory Accounts. We have sourced our annual Gross Capex values for regulatory years 2015, 2016 and 2017 from the Amended Annual Distribution Regulatory Accounts we submitted to the AER on 8 February 2019. Our Amended RINs for these three years were provided in response to an AER request as part of its pre-lodgement engagement with us on the RFM model[3]. The Amended 2015 Gross Capex values form part of the true-up for 2015 in the roll forward calculation.

Table 12-2: Nominal Net Capex, 1 January 2016 to 30 June 2021

Nominal, $M	2016	2017	2018	2019	2020	2021 (first 6 months)
Gross Capex	315.3	358.6	412.4	459.2	470.7	222.9
Less Disposals	-3.6	-0.4	-0.5	-1.3	-1.3	- 0.7
Less Customer Contributions	-20.7	-33.5	-54.8	-65.3	-67.9	-35.8
Nominal Net Capex	290.9	324.7	357.1	392.6	401.4	186.4
Net Capex recognised in RAB[4]	**298.7**	**332.6**	**367.4**	**404.0**	**411.9**	**188.5**

Source: AusNet Services Roll Forward Model (2016-21).

12.4.2 Regulatory depreciation

In the current regulatory period we have applied depreciation on a forecast basis consistent with the approach required under the Capital Efficiency Sharing Scheme (CESS) incentive scheme. Economic depreciation is calculated by determining the nominal depreciation, and offsetting the CPI indexation for each asset class. The calculation of each of these elements is set out below.

12.4.2.1 Forecast straight line depreciation, 1 January 2016 to 30 June 2021

We have sourced the real $2015 straight line depreciation forecasts by asset class from the most recent determination for the current regulatory period, which has been updated to reflect the approved contingent projects. The PTRM model containing these forecasts includes the 2020 annual cost of debt update and our approved expenditure allowances for contingent projects (REFCL tranches 1, 2 and 3). These forecasts are input into the AER's standard RAB roll forward model and adjusted for actual (outturn) inflation. The table below shows the calculation.

3 AER Pre-lodgement engagement on AusNet's distribution RFM, 16th November 2018.

4 Net Capex recognised in RAB includes a half-nominal WACC allowance.

Table 12-3: Nominal Depreciation, 1 January 2016 to 30 June 2021

$M	2016	2017	2018	2019	2020	2021 (first 6 months)
Forecast straight line depreciation – real $2015	179.6	166.3	174.9	180.9	192.0	96.6
Actual / Forecast inflation	2.7	4.2	7.9	12.1	16.1	9.2
Nominal depreciation	**182.3**	**170.6**	**182.8**	**193.0**	**208.2**	**105.8**

Source: AusNet Services Roll Forward Model (2016-21).

The contingent project decisions (for REFCL Tranches 1, 2 and 3) included the accelerated depreciation of certain assets that were to be replaced under these programs. The RAB has therefore been rolled forward in accordance with these decisions, which are reflected in the latest PRTM for the current period. The straight-line depreciation values shown in the table above were sourced from the PTRM and escalated using actual / forecast inflation.

12.4.2.2 Actual and forecast indexation, 1 January 2016 to 30 June 2021

Clause 6.5.1(e)(3) of the NER requires that the established opening asset base, be adjusted for actual inflation consistently with the indexation method used in the control mechanism. We have applied the definition of CPI to escalate the RAB for the current period in accordance with the approach outlined in the 2016-20 Determination, as follows:

> *CPI is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from the June quarter in regulatory year t–2 to the June quarter in regulatory year t–1, calculated using the following method*:
>
> *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–1*
>
> *divided by*
>
> *The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the June quarter in regulatory year t–2*
>
> *minus one.*[5]

Table 12-4: Actual and forecast inflation, 1 January 2016 to 30 June 2021

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
1 Year Lagged Actual CPI	1.51%	1.02%	1.93%	2.08%	1.59%	1.00%*

Source: AusNet Services Roll Forward Model (2016-21)

** Forecast inflation for 6 months to June 2021 will be updated with actual in the revised revenue proposal.*

5 AER - Final decision AusNet distribution determination - Attachment 14 - Control mechanisms - May 2016, p. 376.

For roll forward purposes we have applied the 'all-lagged' inflation approach for both opening RAB indexation and converting real $2015 to $Nominal forecast straight line depreciation values. This is consistent with the roll forward method used in previous regulatory periods for our Distribution RAB.

Table 12-5: Opening RAB Indexation, 1 January 2016 to 30 June 2021

Nominal, $M	2016	2017	2018	2019	2020	2021 (first 6 months)
RAB indexation	52.0	36.9	73.7	84.5	69.5	46.1

Source: AusNet Services Roll Forward Model (2016-21).

12.4.2.3 Economic depreciation

The calculation of economic depreciation (nominal straight-line depreciation net of RAB indexation) for the current period is shown in the table below.

Table 12-6: Economic Depreciation, 1 January 2016 to 30 June 2021

Nominal, $M	2016	2017	2018	2019	2020	2021 (first 6 months)
Nominal Depreciation	182.3	170.6	182.8	193.0	208.2	105.8
RAB Indexation	-52.0	-36.9	-73.7	-84.5	-69.5	-46.1
Regulatory Depreciation	**130.3**	**133.6**	**109.1**	**108.5**	**138.7**	**59.6**

Source: AusNet Services Roll Forward Model (2016-21).

12.5 Forecast final year asset adjustments

We are proposing several end of period adjustments. These adjustments involve transferring estimated RAB values from existing asset classes to new asset classes, including new classes that were approved in our Contingent Project Applications.

The adjustments can be summarised as follows:

- Transfer $209.1 million ($Nominal) of SCADA/Network control assets from existing long-life network asset classes into a new asset class 'Secondary systems – pre 2016';
- Transfer $2.5 million ($Nominal) from 'Distribution system assets' class into an accelerated depreciation class for existing assets that are to be removed and replaced under Contingent Project 3 - Installation of REFCL devices in 5 Zone Substations (Tranche 3); and
- Transfer a further $1.4 million ($Nominal) from 'Distribution system assets' class into an accelerated depreciation class for existing assets that either have been, or are to be, removed and replaced as part of the first two tranches of the REFCL program already underway. These asset replacements were not previously included in our Tranche 1 and 2 Contingent Project Applications.

- Reallocation of 30 June 2021 closing RAB value ($nominal) from 'Distribution system assets' class into accelerated depreciation classes that were approved under Contingent Projects 1 and 2[6]. This particular adjustment is discussed further below in section 12.6.2.
- Section 13.5 of the regulatory depreciation chapter describes the first three adjustments listed above in further detail including:
- the justification for the proposed adjustments;
- the methodology for estimating the 1 January 2021 opening RAB values; and
- the calculations for proposed remaining lives assigned to the new asset classes, as shown in Table 12-7 below.

The consequential adjustments to the opening TAB are outlined in Chapter 15 – Corporate Tax Allowance, Section 15.5.1.

Table 12-7: Proposed Final Year Asset Adjustments (30 June 2021), $Nominal

RAB Class	Proposed RAB adjustments ($M)	Remaining life of adjustments to RAB (Yrs)
Sub-transmission	-59.8	29.7
Distribution system assets	-161.8	33.7
*Secondary systems – pre 2016 **	209.1	5.3
Accelerated Depr - Distr assets (Contingent Project 1)	3.0	n/a
Accelerated Depr - Distr assets (Contingent Project 2)	5.2	n/a
Accelerated Depr - Distr assets (Contingent Project 3) – Part A	0.3	n/a
- Part B	2.6	2.0
*Accelerated Depr - Distr assets (Other) **	1.4	2.0
Subtotal ($Nominal)	-	

Source: AusNet Services Roll Forward Model (2016-21).

** Denotes the new asset classes proposed by AusNet Services. Further information about these asset classes is contained in section 13.6.*

6 AER Final Decision on AST – Contingent Projects – Installation of Rapid Earth Fault Limiting devices in Zone Substations, Tranche 1 (21st August 2017) and Tranche 2 (31st August 2018).

12.6 Pre-lodgement engagement

As part of our pre-lodgement engagement on the roll forward model the AER suggested some further adjustments in the RFM and/or the PTRM for the 2021-26 period, which are discussed below.[7]

12.6.1 Asset classes

The AER recommended the following asset classes be removed from the PTRM for the 2021-26 period as they were all forecast to be fully depreciated by the end of 2016-20 period.

- 'Standard metering';
- 'Public lighting';
- 'Accelerated Depr Opening RAB Adj – Subtr';
- 'Accelerated Depr Opening RAB Adj – Distr';
- 'Accelerated Depr - Subtr (forecast period)'; and
- 'Accelerated Depr - Distr (forecast period)'.

Consistent with our response dated 27 November 2018[8], we agreed to this and confirmed that we had not included the above asset classes in the Proposal PTRM for the 2022-26 regulatory period.

12.6.2 Accelerated Depreciation classes (Contingent Projects)

The AER suggested using the 'Forecast final year asset adjustment' section in the roll forward model to deal with negative values at the end of the 2016-20 period. In its correspondence with us, the AER stated:

> *We note that the 'Accelerated Depr - Distr assets (Contingent Project 1)' and 'Accelerated Depr – Distr assets (Contingent Project 2)' asset classes would have negative values at the end of the 2016–20 period. We consider that the negative values from these asset classes should be reallocated to the 'Distribution system assets' asset class at the end of the 2016–20 period.*
>
> *This is consistent with the asset class that was associated with accelerated depreciation approved for the two contingent projects (as shown in 'Attachment 27 - AST Distribution Amended Depreciation model' (cells C98:E111 in the 'RAB 2016-2070' tab) which was submitted with AusNet's proposal for contingent project tranche 2. We have made this adjustment using the 'Forecast final year asset adjustment' section (cells G232:J261) in the 'RFM input' tab in our RFM. These two accelerated depreciation asset classes for the contingent projects can then be removed from the PTRM for the 2021–25 period.*[9]

In our roll forward model submitted as part of this regulatory proposal, we have adopted the AER's suggestion and applied the adjustment in the Final Year Asset Adjustments section of the roll forward model. This is consistent with our response provided in writing on 27 November 2018[10].

Prior to this response, we advised that our approach to dealing with these asset classes in the roll forward model was different to the AER's suggested approach. Our approach at that time reflected the timing of expected removal of identified assets from service, i.e., as each stage of delivery of the REFCL program is undertaken in each location. To achieve this outcome in the

7 AER, Prelodgement engagement on AusNet's distribution RFM, 16 November 2018.

8 AST Response – Distribution RFM - AER pre-lodgement engagement (27.11.18), p. 5.

9 AER, Prelodgement engagement on AusNet's distribution RFM, 16 November 2018.

10 AST Response – Distribution RFM - AER pre-lodgement engagement (27.11.18), p. 5.

preliminary roll forward model[11], we inserted additional formulae into the 'RAB roll forward' and 'Total RAB roll forward' sheets to reallocate opening RAB values into each accelerated depreciation class.

In doing so this effectively achieved the same outcome as the AER's suggested approach, although some minor balances remained (in total $0.2 million) in the accelerated depreciation classes as at 1 January 2021. These remaining balances, however, were validated by the timing of RAB transfers reflected in our year-by-year tracking Depreciation model, which was updated as part of the approved Contingent Project Applications (Tranches 1, 2 and 3).

We must therefore make a further adjustment in our Depreciation tracking model to remove these minor balances to ensure alignment with closing RAB values contained in the roll forward model for 2016-20 period.

Below are the final year asset adjustments as reflected in our roll forward model. These adjustments are also included in the total amounts shown in Table 12-7 above.

Table 12-8: Final Year Asset Adjustments (30 June 2021) – Approved Contingent Projects, $Nominal

RAB Class	Proposed RAB adjustments ($M)	Remaining life of adjustments to RAB (Yrs)
Distribution system assets	-11.0	n/a
Accelerated Depr - Distr assets (Contingent Project 1)	2.9	n/a
Accelerated Depr - Distr assets (Contingent Project 2)	5.2	n/a
Accelerated Depr - Distr assets (Contingent Project 3) – Part A	0.3	n/a
*– Part B**	2.6	2.0

Source: AusNet Services Roll Forward Model (2016-21).

* We proposed $2.6 million ($Nominal) of accelerated depreciation of existing network assets commencing from the start of next regulatory period as part of its approved contingent project application (REFCL Tranche 3). This proposal is discussed further in section 13.7.1 of the Depreciation chapter.

Below are the final year adjustments required to our Depreciation tracking model to align the closing RAB values with the roll forward model.

Table 12-9: Asset Adjustments – Closing Asset Base, $Nominal

RAB Class	2016	2017	2018	2019	2020
Distribution system assets	-2.76		-5.45		0.16
Accelerated Depr - Distr assets (Contingent Project 1)	2.76				-0.02

11 AST, AusNet D 2016-20 RFM (DRAFT).xlsm (4th December 2018)

RAB Class	2016	2017	2018	2019	2020
Accelerated Depr - Distr assets (Contingent Project 2)			5.13		-0.13
Accelerated Depr - Distr assets (Contingent Project 3) – "Part A"			0.32		
Subtotal ($Nominal)	**-**	**-**	**-**	**-**	**-**

Source: AusNet Services Depreciation tracking model (2016-21).

12.7 Forecast RAB over the 2022-26 regulatory period

The opening RAB as at 1 July 2021 is rolled forward during the 2022-26 regulatory period to reflect our capex forecast, forecast straight line depreciation and the indexation of the RAB. The calculations, which are consistent with the AER's Roll Forward Model and Post Tax Revenue Model (Version 4), are summarised in the table below.

Table 12-10: Regulatory Asset Base roll forward 1 July 2021 to 30 June 2026 ($m nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	4,715.1	4,898.9	5,061.6	5,225.3	5,370.5
Plus capex, net of contributions and disposals	321.9	312.6	319.8	310.7	319.9
Less straight-line depreciation	-253.7	-269.8	-280.2	-293.5	-306.0
Plus nominal forecast inflation on opening RAB	115.5	120.0	124.0	128.0	131.6
Closing RAB	**4,898.9**	**5,061.6**	**5,225.3**	**5,370.5**	**5,516.0**

Source: AusNet Services PTRM 2022-26.

In accordance with clause S6.2.1(e)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of standard control services in accordance with our approved CAM is included in the RAB. It should be noted that the nominal capital expenditure in the table above excludes capital contributions. Customer initiated capital expenditure included in the RAB is the gross (total) expenditure net of customer capital contributions.

12.8 Supporting documentation

The following documents are provided in support of this chapter:

- Our proposal models, including the PTRM models, Proposal RFM model (2016-21) and Depreciation tracking model (2016-21);
- Historical amended Annual reporting RIN templates (previously provided to the AER):
  - Spreadsheet entitled '1. AusNet Services - 2015 Financial Information (Restated Capex Table 3Provisions).xlsx'. (Refer to 3a Capex(T) – Table 3)
  - Spreadsheet entitled '2016 AusNet Electricity Services Regulatory Accounts - Consolidation (AER Version).xlsm'. (Refer to 8.2 Capex – Table 8.2.4)
  - Spreadsheet entitled '2017 AusNet Electricity Services Regulatory Accounts Consolidated revised v2.xlsm'. (Refer to 8.2 Capex – Table 8.2.4)

- Spreadsheet entitled “Selected Network SCADA assets opening RAB calculation”;

13 Depreciation

13.1 Key points

- We are using the approach approved at the last reset for depreciating the opening RAB using the year-by-year tracking method.
- We are proposing accelerated depreciation of secondary system assets using recalculated remaining lives, which more reasonably reflects their remaining economic lives.
- We are also proposing accelerated depreciation of assets which will either be or already have been decommissioned as part of our bushfire mitigation projects.

13.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 13.3 briefly discusses our depreciation methodology;
- Section 13.4 presents our proposed opening RAB depreciation over the 2022-26 regulatory period;
- Section 13.5 sets out our standard asset lives in the regulatory asset base for the 2022-26 regulatory period, including our proposed depreciation of forecast capex (as set out in Chapter 9);
- Section 13.6 explains our proposed accelerated depreciation of existing SCADA/Network control assets in the 2022-26 regulatory period;
- Section 13.7 explains our proposed accelerated depreciation of decommissioned assets over the 2022-26 regulatory period in relation to our bushfire mitigation projects;
- Section 13.8 presents our proposed depreciation allowance for the 2022-26 regulatory period; and
- Section 13.9 lists the supporting documentation for this chapter.

13.3 Depreciation methodology

Our proposed methodology for the 2022-26 regulatory period is consistent with the AER's most recent determination for our Electricity Distribution business for the 2016-20 regulatory period. Our approach is briefly summarised as follows:

- Apply straight-line depreciation to assets contained in the opening RAB using the year-by-year tracking approach;
- Apply straight-line depreciation to new assets that will be added to the RAB over the 2022-26 period according to their standard lives;
- Accelerate depreciation of assets that will be decommissioned in the current or forthcoming period.

In addition, we are proposing accelerated depreciation of secondary system assets that were installed on the distribution network prior to 2016. This proposal is explained further in section 13.6 below.

13.4 Opening RAB

Straight-line depreciation of the opening RAB is calculated using a disaggregated approach. We have applied our own model, which uses the year-by-year tracking approach to calculate depreciation charges for the forthcoming regulatory period. The depreciation model sets out the values, inputs and calculations used to determine forecast depreciation of the opening RAB in

2021. The outputs from this model are included as inputs to the Post Tax Revenue Model (Version 4) (PTRM), which is submitted alongside this regulatory proposal.

Below are the proposed straight-line depreciation values for the opening RAB as reflected in the PTRM model.

Table 13-1 Proposed Opening RAB depreciation (2022-26), $Jun 2021

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opening RAB depreciation	247.5	238.6	227.3	217.5	207.9	1,138.9

Source: AusNet Services PTRM (2022-26)

13.5 Standard asset lives

Our proposed standard asset lives for new additions in the forthcoming regulatory period are unchanged from the current period, and are presented in the table (below). The standard life for Equity raising costs reflects the weighted average life of the total Capex forecast for the 6 month period (Jan to Jun-21) and the 2022-26 regulatory period.

Table 13-2: Proposed standard asset lives for new additions to the RAB

Asset class	Standard life (Yrs)
Subtransmission	45
Distribution system assets	50
SCADA/Network control	10
Non-network general assets - IT	5
Non-network general assets - Other	5
Non-network - Metering related IT	7
Land	n/a
Non-network Leasehold Land & Buildings - 2021-22 *	23.7
Non-network Leasehold Land & Buildings – 2025-26 *	5
Equity raising costs (Jan-Jun’21)	46.8
Equity raising costs (2022-26)	44.7

Source: AusNet Services.

Two new asset classes have been established in the PTRM for this regulatory proposal in relation to forecast capitalised leasing costs for the 2022-26 period. These capitalised lease costs relate to changes in Australian accounting standards. Further details on these changes are contained in Appendix 9E.

Table 13-3 (below) sets out the proposed straight-line depreciation for new additions to the RAB in the 2022-26 regulatory period. These RAB additions reflect our proposed forecast capital expenditures as contained in Chapter 9 of this regulatory proposal.

Table 13-3 Proposed depreciation of New Assets (2022-26), $Jun 2021

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
New Assets	-	18.3	33.1	48.8	63.0	163.2

Source: AusNet Services PTRM (2022-26).

13.5.1 Remaining asset lives

As we use our own tracking model for depreciation of the opening RAB, remaining lives information for existing assets is not required to be entered in the PTRM model. The remaining lives for existing assets in the opening RAB are unchanged with the exception of the asset classes contained in the table below.

Table 13-4 Additional asset classes

Asset class	Remaining life (Yrs)
Secondary systems (pre 2016)	5.3
Accelerated Depr - Distr assets (Contingent Project 3)	2.0
Accelerated Depr - Distr assets (Other)	2.0

Source: AusNet Services.

These additional asset classes have implications for the accelerated depreciation, which is discussed in sections 13.6 and 13.7 below.

13.6 Accelerated depreciation of SCADA/Network control assets

We propose accelerated depreciation of existing SCADA/Network control assets in the opening RAB over the 2022-26 regulatory period. This relates to network SCADA, protection and control system assets which historically have been depreciating in the RAB under long life asset classes up until 2015. Our proposal seeks to transfer selected network assets into a new asset class from July 2021 and depreciate them over their calculated weighted average remaining life of 5.3 years.

Our proposed approach conforms with clause 6.5.5(b)(1) of the NER, which requires that “the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets”.

We are proposing accelerated depreciation of the existing SCADA/Network control assets, including a portion of the current fleet of protection relays (not all types) and the current fleet of remote terminal units. Any network assets of this type that were replaced or decommissioned are not included in our accelerated depreciation proposal. Our proposal includes the following SCADA, protection and control system assets that were installed in our distribution zone substations prior to 1 January 2016:

- ‘Intelligent Electronic Device’ (IED) protection relays operating at 66 kV and below; and
- Remote Terminal Units (RTUs) which interfaces the physical relay and monitoring devices with the SCADA system.

These assets have much longer lives assumed (between 33 and 50 years) than the modern equivalent assets that were installed from 2016 onwards (which have 10 year lives).

As outlined in our RAB chapter, we propose to transfer an estimated opening total RAB value of $209.1 million ($Nominal) out of the existing long-life asset classes into a new asset class ‘*Secondary systems – pre 2016*’.

The table below shows the proposed straight-line depreciation profile of these assets over the 2022-26 period.

Table 13-5 Proposed SCADA/Network control assets accelerated depreciation (2022-26), $Jun 2021

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
IED protection relays	34.3	34.3	34.3	34.3	34.3	171.3
Distribution RTUs	5.5	5.5	5.5	5.5	5.5	27.4
Total	**39.7**	**39.7**	**39.7**	**39.7**	**39.7**	**198.7**

Source: AusNet Services.

The table below shows the required offsetting depreciation adjustments under the existing long-life asset classes to ensure depreciation of the transferred assets are not double counted.

Table 13-6 Depreciation offset (2022-26), $Jun 2021

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Existing asset classes	-7.6	-7.6	-7.6	-7.6	-7.6	-37.8

Source: AusNet Services.

The above offsetting depreciation adjustments are contained in our opening RAB depreciation tracking model (up to 30 June 2021).

The following sections outline our approach for establishing the 2021 opening RAB values and their respective remaining lives.

13.6.1 Historical standard asset lives

Prior to 1 January 2016, our expenditures on network SCADA, protection and control were reported under long life network asset classes within the distribution RAB. The standard lives that applied under the ESC RAB roll forward approach were 33 years up until 2011, which subsequently increased to a standard life of between 45 and 50 years in the 2011-15 regulatory period. These historical standard lives are presented in Table 13-7 below.

Table 13-7: Historical RAB lives applied for Network SCADA and IT SCADA assets

			Standard Life		
Expenditure Type	**Asset Class**	**Voltage level**	**Periods prior to 2011**	**2011-2015**	**2016-2020**
Network SCADA, Protection & control	Subtransmission	66 kV	33	45	
	Distribution system assets	<66 kV	33	50	
	SCADA/Network control	All			10
IT systems SCADA & Comms	SCADA/Network control	n/a	5	5	
	Non Network - IT	n/a			5

Source: AusNet Services.

This shows that there are only two SCADA asset classes that apply in the current regulatory period (2016-20):

- SCADA/Network Control, which has an asset life of 10 years; and
- Non Network – IT, which has an asset life of 5 years.

The standard life of 10 years for SCADA/Network Control assets was approved by the AER in its determination for the current period (2016-20).[149] For tax purposes the ATO also recommends a tax life of 10 years for Network SCADA and Comms assets.[150]

There is a significant difference in the asset lives for SCADA/Network Control which has applied since 2016 (of 10 years) and the asset lives which applied prior to 2016, which varied between 33 years and 50 years. Ten years more closely reflects the useful lives of these network assets rather than 33, 45 or 50 years. We have not previously proposed any transfers or accelerated depreciation for SCADA/Network control assets that were installed on the network prior to 1 January 2016. Therefore, these assets have remained in the long life asset classes shown in Table 13-7 above and form part of the July 2021 opening RAB values contained in the roll forward model (before final year asset adjustments).

In sections below we explain how the accelerated depreciation for IED protection relays and RTUs has been calculated. As already noted, our approach is focused on achieving a depreciation schedule that complies with clause 6.5.5(b)(1) of the NER.

13.6.2 Accelerated depreciation of selected SCADA/Network control assets

Our electricity distribution network has approximately 3,143 protection relays and 93 remote terminal units (RTUs) operating in zone substations throughout the eastern part of Victoria.

These protection and control systems are designed to de-energise a faulted circuit to minimise property and equipment damage, reduce the risk to human life and maintain supply reliability to unaffected circuits as well as maintain network operating voltages within the limits of the

149 AER - Final decision AusNet distribution determination - Attachment 5 - Regulatory depreciation - May 2016, pp. 9-10.

150 ATO Tax Ruling 2018/4 (TR 2018/4).

Electricity Distribution Code. In addition, protection and control systems enable control of network switching and SCADA schemes and provide instrumentation capabilities.

13.6.2.1 Estimating Opening RAB values

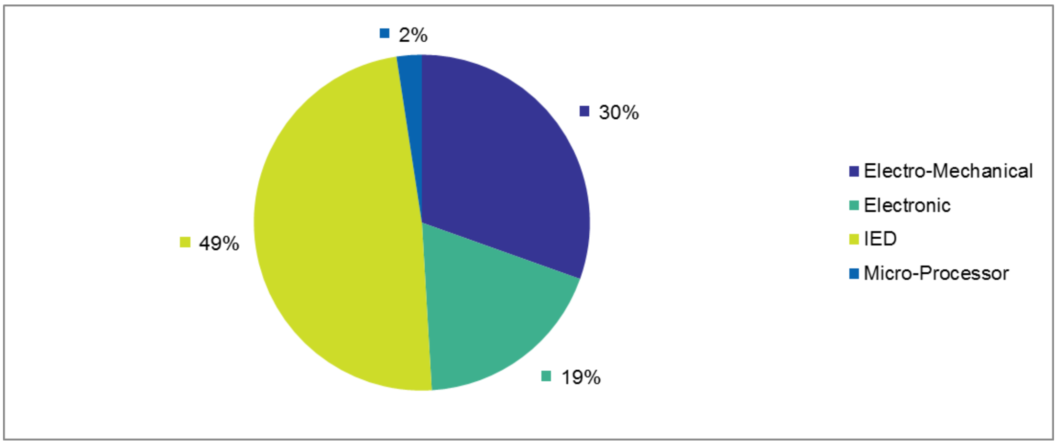
Our approach to estimating the opening RAB values for selected SCADA/Network control assets is similar to our methodology used in the 2016-20 electricity distribution revenue 'revised proposal' and recently approved contingent projects (REFCL Tranches 1-3).

In the absence of a disaggregated RAB it is necessary to estimate the opening share of RAB within the existing asset long life asset classes. The following sections describe our approach to estimating the 1 July 2021 opening RAB shares for selected protection relay devices and our entire RTU fleet that were installed prior to 2016. Once these opening RAB values are established we then propose to accelerate the depreciation of these assets over their 'revised' average remaining lives. That is, the existing remaining lives as at 1 July 2021 (based on standard lives of between 33 and 50 years) are shortened in order to reflect their expected remaining service lives. Further details on the revised remaining lives calculations in the RAB roll forward are contained in section 13.6.3 below. Further details on the revised remaining TAB lives are contained in Chapter 15 (Corporate Tax), section 15.5.2.

13.6.2.2 Protection relays

The protection relays operating in our distribution network consist of 49% Intelligent Electronic Devices, 30% electro-mechanical, 19% electronic and 2% micro-processor based relays.

Figure 13-1: Protection Relay fleet by Type



Source: AusNet Services.

The most recent type of these devices installed within our zone substations can be referred to as 'Intelligent Electronic Devices' (IED). These protective relaying devices are a microprocessor based controller capable of performing multiple functions including protection, control, autoreclose, self-monitoring and communications.

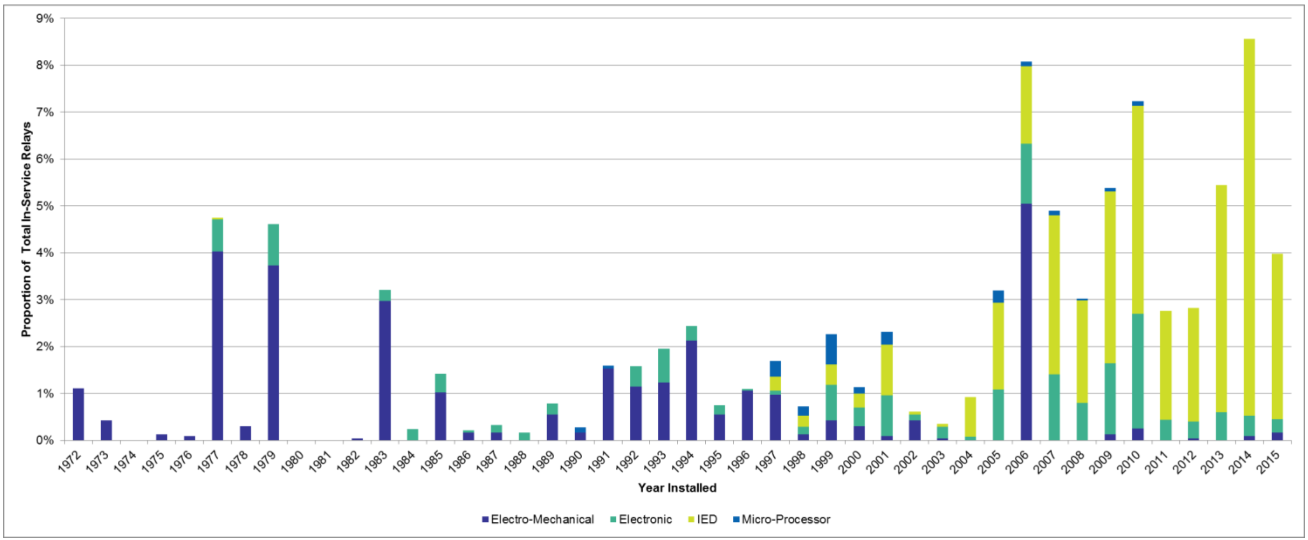
Replacing the ageing relay population over time with more modern devices has been driven by several factors including, obsolescence, deterioration, lack of manufacturer support and the need to comply with safety compliance directives from ESV, i.e., to adjust the tripping sequence and auto reclose functionality of feeder protection devices on total fire ban days. This particular safety requirement was a direct outcome of the Powerline Bushfire Safety Taskforce Recommendation 32.[151] Functionality, and the need to adopt to a modern standardised design for station equipment using integrated functions in an intelligent device, have also been important factors in determining the rate of replacement.

151 2009 Victorian Bushfires Royal Commission, Final Report: Summary, July 2010, p. 30.

While the economic life of these intelligent devices in our Distribution RAB is 10 years, historically these assets (prior to 2016) have been depreciating over a significantly longer period of time.

Figure 13-2 below shows the age profile of the total protection relay fleet as at 1 January 2016. We are only proposing accelerated depreciation for the IED protection relays in the RAB from 1 January 2021 while the older relay types will remain in the long-life asset classes.

Figure 13-2: Protection Relay Age profile as at 1 January 2016



Source: AusNet Services.

We have calculated the estimated total remaining value for these IED protection relays in the RAB to be $180.3 million ($Nominal) as at 1 July 2021.

Our historical investment in IEDs has spanned multiple regulatory periods starting from the late 1990's. This has included a combination of replacement programs and selected replacements, i.e., as part of zone substation rebuilds, where it was economic to do so. For this reason, and the length of time involved, including periods which were under the previous ESC regime, our historical cost and volume data on a project by project basis is not readily available. Therefore, an estimate of the residual RAB value is required based on the best available data. Our approach relies on annual in-service volume data, unit rates and inflation assumptions to derive the value of additions in the RAB starting from 1997.

Our calculation of the estimated residual value in the RAB for IED protection relays involved the following steps:

1. Establish the total population of in-service IED protection relays installed on the distribution network as at 1 January 2016;
2. Estimate the historical annual additions to the RAB using an asset age profile (based on the total number of in-service relays) including establishing the portion of relays operating in the 66 kV network and below;
3. Apply the current unit replacement cost including capitalised overheads (in real $2018);
4. Estimate historical annual additions into the RAB up until 2015 using the asset age profile (from step 2) and current unit replacement cost (adjusted for actual inflation); and
5. Apply a nominal RAB roll forward approach to the end of the current regulatory period by deducting annual straight-line depreciation and applying indexation over time.

Step1 – Establish the total population of IED protection relays as at 1 January 2016

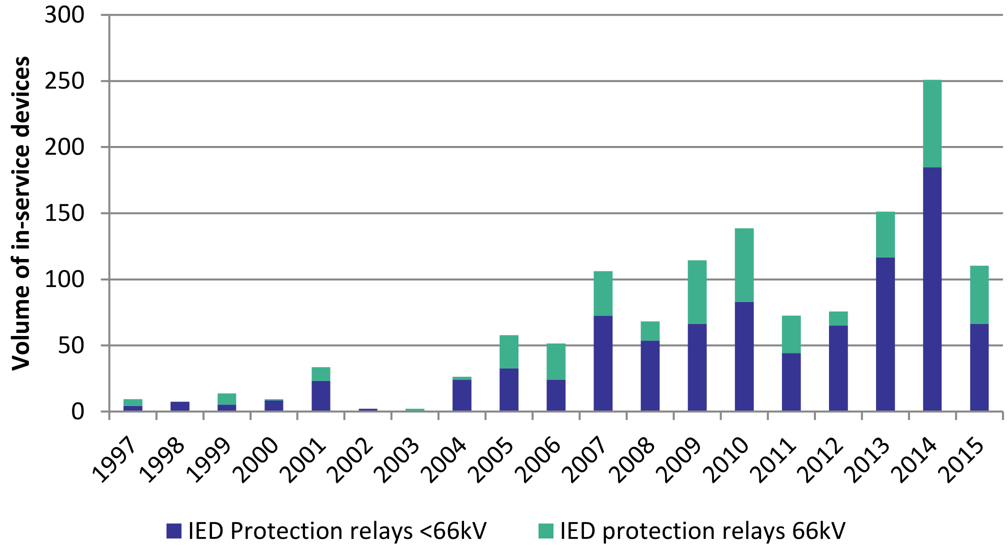
We obtained the total population of IED protection relays as at 1 January 2016 from our protection and control systems strategy.[152] At that date, we had a total of 1,302 IED protection relays installed on the distribution network which represents 45% of the total population of in-service protection relays at that time.

Step 2 – Estimate the historical annual additions to the asset base

We determined the annual volume of relays that were added to the RAB using an asset age profile for IED protection relays. The annual volumes shown below in Figure 13-3 were sourced from our protection and control systems strategy.[153]

Figure 13-3 shows the age profile for the fleet of in-service IED protection relays as at 1 January 2016.

Figure 13-3: IED Protection relay age profile as at January 2016



Year of installation	Pre '97	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
IED protection relay < 66kV	1	4	7	5	8	23	2	0	24	33	24	72	54	66	83	44	65	117	185	66	884
IED protection relay 66kV	0	5	0	8	1	11	0	2	2	25	27	34	15	48	56	28	11	35	66	44	418
Total	**1**	**9**	**7**	**14**	**9**	**34**	**2**	**2**	**26**	**58**	**51**	**106**	**68**	**114**	**139**	**72**	**76**	**151**	**251**	**110**	**1302**

Source: AusNet Services.

Step 3 - Apply the current unit replacement cost

We obtained the current unit replacement cost for an IED protection relay including overheads of c-i-c (real $2018) for devices operating at less than 66 kV and c-i-c (real $2018) for devices operating at 66 kV. These unit rates were sourced from subject matter experts who reviewed the historical cost of installing these protection relay devices. The unit rates are consistent with those used in the capital expenditure forecast for the 2022-26 period included in this regulatory proposal.

Step 4 - Estimate the annual additions into the RAB up until 2015

We took the unit rates from step 3 above and converted these into real $1997 values using a CPI factor of 0.6027. We then applied these rates to the annual volumes shown in Figure 13-3 above. This produced a set of annual additions in real $1997 terms which were then input into the RAB roll forward calculation (step 5). We did not allow for the half year allowance consistent with the

[152] AusNet Services, AMS 20-72 – Electricity Distribution Network, Protection and Control systems (June 2019).

[153] AusNet Services, AMS 20-72 – Electricity Distribution Network, Protection and Control systems (June 2019).

methodology applied under the ESC approach for periods up to and including 2010. For 2011-15 additions we included the half year nominal WACC allowance. Refer to the supporting workings contained in attachment 'Selected Network SCADA assets opening RAB calculation.xlsx'.

Step 5 - Apply a nominal RAB roll forward approach

Commencing from 1 January 1997, we applied a nominal RAB roll forward approach by deducting nominal straight-line depreciation and applying indexation over time. We used the additions from step 4 above and applied actual inflation consistent with the standard roll forward approach. For the annual depreciation schedule, we applied the standard RAB lives which applied under the long life asset classes for regulatory periods prior to the 2016-20 control period (refer to Table 13-7 above).

The calculated closing RAB values for the IED devices as at 30 June 2021 are shown in the table below.

Table 13-8 Estimated Closing RAB for IED protection relays as at 30 June 2021

Asset type	Asset class	Closing RAB value ($m)	Average remaining life (Yrs)	Recalculated average remaining life (Yrs)
IED protection relays 66 kV	Subtransmission	59.8	29.7	5.3
IED protection relays < 66 kV	Distribution system assets	120.6	34.6	5.7
Total		**180.3**		

Source: AusNet Services.

In our RAB roll forward model we have transferred these calculated closing June 2021 values out of existing long life asset classes '*Subtransmission*' and '*Distribution system assets*' into the new class '*Secondary systems – pre 2016*'. These transfers are contained in the forecast final year asset adjustments section of the RFM.

Based on the recalculated remaining lives as at 1 July 2021, the proposed straight-line depreciation of these IED devices in the RAB over the 2022-26 period is shown in Table 13-9 below.

Table 13-9 Proposed depreciation profile of IED protection relays (2022-26), $Jun 2021

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight line depreciation	34.3	34.3	34.3	34.3	34.3	171.3
Depreciation offset	-6.4	-6.4	-6.4	-6.4	-6.4	-32.2
Total	**27.8**	**27.8**	**27.8**	**27.8**	**27.8**	**139.1**

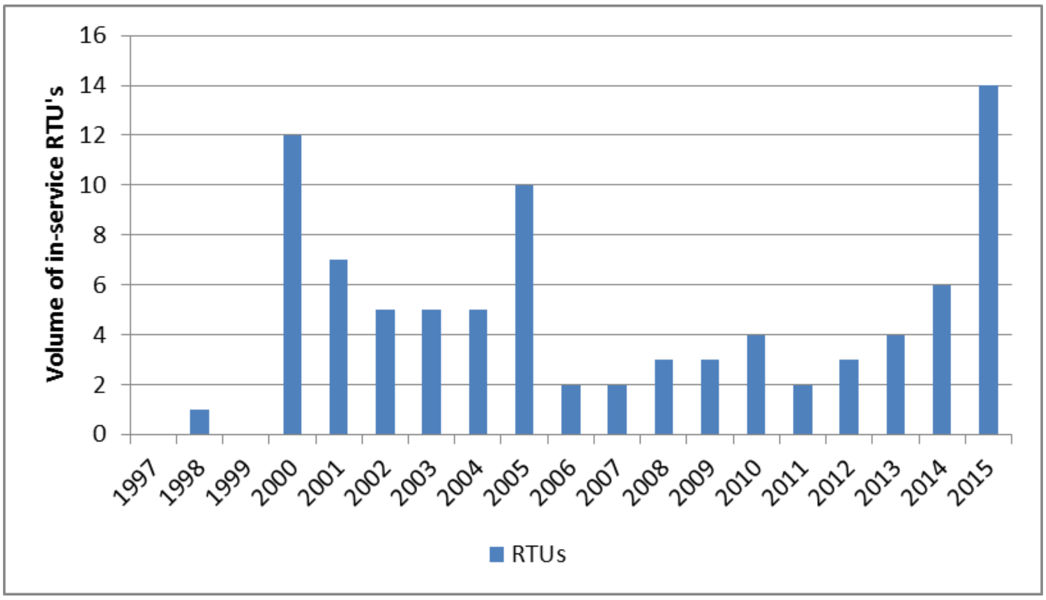
Source: AusNet Services.

13.6.2.3 Remote Terminal Units

As at 1 January 2016, we had a total of 88 remote terminal units (RTUs) installed and operating in our distribution zone substations.

The age profile of our RTU fleet up until 2016 is shown below in Figure 13-4.

Figure 13-4: Distribution RTU Age profile as at January 2016



Source: AusNet Services.

Similar to the IED protection relays, the economic life of an RTU in our Distribution RAB is 10 years. Historically, and for periods prior to 2016, this asset type has been depreciating over a significantly longer period of time in the RAB. We propose to address this issue by recalculating the remaining lives in both the RAB and TAB at the start of the next period. Our remaining lives calculations are explained further in section 13.6.3 below.

We have calculated the estimated total remaining value for these 88 RTUs in the RAB to be $28.8 million ($Nominal) as at 1 July 2021.

Our calculation of the estimated residual value in the RAB involved the same steps used in the calculation of IED protection relays. These steps include:

1. We established the total population of in-service RTUs installed on the distribution network as at 1 January 2016, being 88. This number was sourced from our protection and control systems strategy.
2. We estimated the historical annual additions to the RAB using an asset age profile of the current RTU fleet as shown in Figure 13-4 above.
3. We applied the current unit replacement cost including capitalised overheads (in real $2018) of c-i-c. The unit rate was sourced from a detail cost build up for the replacement of an MD1000 type RTU. The unit rate is consistent with our capital expenditure forecast for the 2022-26 period included in this regulatory proposal. Approximately 49% of RTUs installed at zone substations consist of the MD1000 type;
4. We estimated the annual additions into the RAB up until 2015 using the asset age profile and current unit replacement cost (adjusted for actual inflation), in accordance with the approach outlined above for IED protection relays;
5. We applied a nominal RAB roll forward approach to the end of the current regulatory period by deducting annual straight-line depreciation and applying indexation over time. Refer to the supporting workings contained in attachment 'Selected Network SCADA assets opening RAB calculation.xlsx'.

Table 13-10 Estimated Closing RAB for RTUs as at 30 June 2021

Asset type	Asset class	Closing RAB value ($m)	Average remaining life (Yrs)	Recalculated average remaining life (Yrs)
Remote Terminal Units	Distribution system assets	28.8	29.5	3.4

Source: AusNet Services.

In our RAB roll forward model we transferred the closing June 2021 value out of existing long-life asset class '*Distribution system assets*' into the new class '*Secondary systems – pre 2016*'. This transfer is contained in the forecast final year asset adjustments section of the Proposal RFM.

Based on the recalculated average remaining lives as at 1 July 2021, the proposed straight-line depreciation of these RTUs in the RAB over the 2022-26 period is shown in Table 13-11 below.

Table 13-11 Proposed depreciation profile of Distribution RTUs (2022-26), $Jun 2021

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight line depreciation	5.5	5.5	5.5	5.5	5.5	27.4
Depreciation offset	-1.1	-1.1	-1.1	-1.1	-1.1	-5.6
Total	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**21.8**

Source: AusNet Services.

Further details on the above calculations are contained in supporting attachment 'Selected Network SCADA assets opening RAB calculation.xlsx'.

13.6.3 Recalculated remaining lives in the RAB

Our proposed closing RAB adjustments for the selected SCADA/Network control assets are shown in Table 13-12 below. Since there are multiple transfers proposed from existing asset classes into a single new asset class '*Secondary systems – pre 2016*', we calculated a weighted average remaining life of 5.3 years across all asset types.

Table 13-12 Estimated Closing RAB for selected SCADA/Network control assets as at 30 June 2021

Asset type	Asset class	Closing RAB value ($m)	Average remaining life (Yrs)	Recalculated average remaining life (Yrs)
IED protection relays 66 kV	Subtransmission	59.8	29.7	5.3
IED protection relays < 66 kV	Distribution system assets	120.6	34.6	5.7
Remote Terminal Units	Distribution system assets	28.8	29.5	3.4

Asset type	Asset class	Closing RAB value ($m)	Average remaining life (Yrs)	Recalculated average remaining life (Yrs)
Total / Weighted Average		**209.1**	**32.5**	**5.3**

Source: AusNet Services.

Table 13-13 below shows the average age profile by Asset Type as at 30 June 2021 based on the historical standard lives (of 33 years for assets installed up until 2010 and 45 or 50 years for assets installed between 2011-15).

Table 13-13 Selected SCADA/Network control RAB remaining lives as at 30 Jun 2021

Asset type	Asset class	Average age as at Jun 2021 (Yrs)	Expected service life (Yrs)	Revised average remaining life (Yrs)
IED protection relays 66 kV	Subtransmission	9.7	15.0	5.3
IED protection relays < 66 kV	Distribution system assets	9.3	15.0	5.7
Remote Terminal Units	Distribution system assets	11.6	15.0	3.4
Weighted Average				**5.3**

Source: AusNet Services.

The revised remaining lives shown in the table above are calculated using an expected average service life of 15 years and deducting the average age as at 30 June 2021.

13.7 Accelerated depreciation of decommissioned assets – REFCLs

We propose accelerated depreciation over the 2022-23 period in total of $3.9 million ($Jun 2021) relating to assets that either have already been, or are planned to be, replaced as part of our safety-related capital expenditure programs.

The nature of the assets and asset classes is such that they will be replaced ahead of the end of their expected economic and/or technical lives. The AER has approved our proposal to accelerate depreciation of certain high bushfire risk assets which have been, or are forecast to be, replaced as part of our safety programs and approved this approach in our 2016-20 Distribution Determination[154] and our REFCL contingent project applications.

Our proposal to apply accelerated depreciation to the identified assets in the contingent project applications accurately reflects changes to the remaining economic lives of those assets. Accordingly, our proposal conforms to the requirement in NER clause 6.5.5(b)(1).[155]

154 AER - Final decision, AusNet distribution determination - Attachment 5 - Regulatory depreciation - May 2016, p. 5-13.

155 NER clause 6.5.5(b)(1) requires that “the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets”.

13.7.1 Contingent project - Installation of REFCL devices in 5 Zone substations (Tranche 3)

As contained in our Tranche 3 contingent project application, we proposed accelerated depreciation of existing assets in the opening RAB over the CY2021-22 period, totalling $2.68 million ($Dec 2020). This included the intervening six months from January to June 2021.

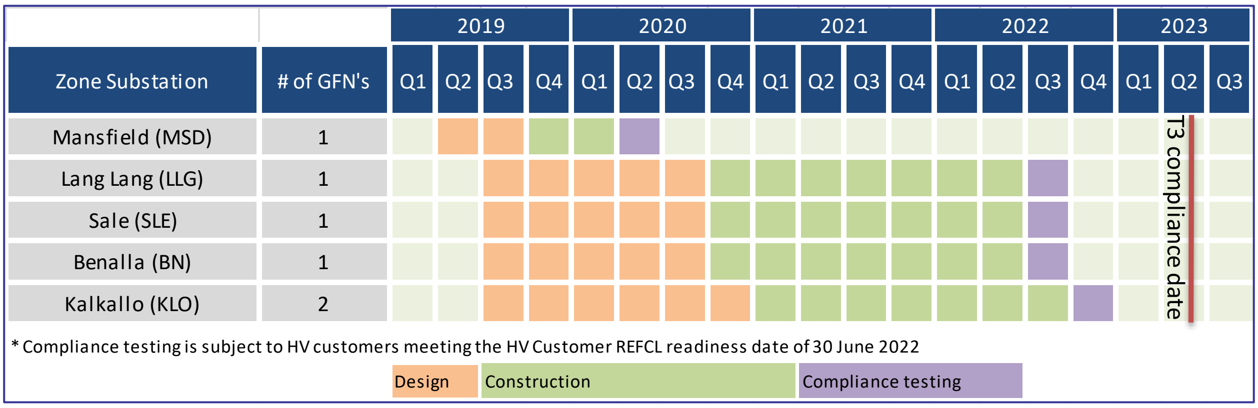
As outlined in our Tranche 3 application we used the following methodology to estimate the opening RAB values, which is consistent with the methodology used in our recently approved contingent project applications:

1. Identify assets that are to be removed in both the current period (2016-20) and next regulatory period (understood to be CY2021-25 at the time, now FY2022-26).
2. Estimate opening RAB value of relevant asset classes (as at January 2015).
3. Determine the proportion of asset class to be accelerated (i.e. the proportion removed from asset base).
4. Roll forward the estimated 2015 opening RAB values:
    a. For assets removed in the current period, roll forward the estimated 2015 opening RAB values to January 2019 using a nominal RAB roll forward approach.
    b. For assets to be removed in the following period (2022-26), roll forward the estimated 2015 opening RAB values to July 2021 using a nominal RAB roll forward approach.

In our contingent project application, we proposed accelerated depreciation of assets that were being replaced in the current regulatory period at Mansfield sites. The AER has recently approved this proposal in its final decision[156] which included an accelerated depreciation allowance of $0.32 million (real $2019) for assets to be replaced over the remainder of the current period (including 2019 and 2020). Therefore, this accelerated depreciation proposal covers only the remaining sites at Benalla (BN), Sale (SLE), Lang Lang (LLG) and Kalkallo (KLO).

Figure 13-5 below shows the timeline for delivery of work to be undertaken at each zone substation and along our high voltage distribution lines. The construction phase will begin in late 2020 at three of these sites (LLG, SLE and BN) with the fourth site (KLO) beginning in the first quarter of 2021.

Figure 13-5: REFCL Tranche 3 timeline



Source: AusNet Services.

156 AER, Final Decision AusNet Services Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche three, 3 October 2019.

We are therefore proposing to accelerate depreciation of the assets over the first 2 years of the 2022-26 regulatory period in line with the construction timeline for the four sites, excluding Mansfield.

The types of assets considered in our accelerated depreciation proposal under Tranche 3 Contingent Project Application include:

- protection relays within zone substations;
- surge arrestors;
- automatic circuit reclosers (ACRs);
- sectionalisers; and
- 22 kV HV overhead cables.

The table below shows the proposed accelerated depreciation of existing assets over the 2022-26 period.

Table 13-14: Proposed Accelerated Depreciation Allowance – 2022-26 Period ($m, $Jun 2021)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight line depreciation	1.3	1.3	-	-	-	2.5
Depreciation offset	-0.1	-0.1	-0.1	-0.1	-0.1	-0.6
Total	**1.2**	**1.2**	**-0.1**	**-0.1**	**-0.1**	**1.9**

Source: AusNet Services.

The above offsetting depreciation adjustments are contained in our opening RAB depreciation tracking model under the existing asset class '*Distribution system assets*'.

The total estimated opening RAB value of $2.53 million ($Jun 2021) will be depreciated over 2 years starting from 1 July 2021 under the new asset class '*Accelerated Depr - Distr assets (Contingent Project 3)*'. This asset class was established in our submitted models as part of our Tranche 3 contingent project application.

Further details on our Tranche 3 accelerated depreciation proposal are contained in our Contingent Project Application.[157]

13.7.2 Other REFCL related asset retirements (not funded by existing CPA applications)

We propose a further $1.36 million ($Jun 2021) of accelerated depreciation of existing assets over 2022-23 in relation to high voltage overhead cable replacements that either have been, or are to be, replaced under Tranches 1 and 2 of the REFCL program. We did not seek specific funding for the accelerated depreciation of these decommissioned HV cables in its contingent project applications for Tranches 1 and 2.

The methodology for estimating the opening RAB values is consistent with the approach outlined above in section 13.6.1.

The total length of HV underground cable that will be decommissioned spans 17.8 kilometres, comprising 6.2 kilometres as part of Tranche 1 and 11.6 kilometres as part of Tranche 2. While our Tranche 2 contingent project allowed for some accelerated depreciation for HV cables, that

157 AST, Contingent Project Application – Tranche 3 (Bushfire Mitigation) – Confidential, 31 May 2019, pp. 55-57.

allowance was only for the proactive volume replacements. The additional reactive volume replacements (run to failure) are now included in our proposed accelerated depreciation.

The list of Tranche 1 sites where this work has already been completed is shown below in the table below.

Table 13-15: Completed HV cable replacements – Tranche 1 sites

Zone Substation	Feeder	TOTAL km	Completion Date
WGI	WGI21	4.1	20-Jul-19
MYT	MYT12	0.1	25-Sep-18
KMS	KMS12	0.03	12-Jul-18
RUBA	RUBA22	0.8	15-Jun-18
WN	WN2	0.3	12-Mar-19
	WN4	0.2	11-Sep-18
	WN6	0.2	15-Sep-18
SMR	SMR24	0.1	1-Oct-19
WYK	WYK13	0.4	30-Jun-18
Total		**6.2**	

Source: AusNet Services

For Tranche 2, the reactive volume replacements expected in the current regulatory period and next regulatory period are shown in Table 13-16 below.

Table 13-16: Reactive program of HV cable replacements – Tranche 2 sites

REFCL Station	Run-to-Failure Replacement Length (km)
BDL	1.5
BGE	1.9
ELM	2.3
FGY	1.8
LDL	1.8
MOE	0.7
RWN	0.9
WOTS	0.6
Total	**11.6**

Source: AusNet Services

Table 13-17 below shows the timing of the proposed accelerated depreciation over the 2022-26 period.

Table 13-17: Proposed Accelerated Depreciation Allowance – 2022-26 Period ($m, $Jun 2021)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight line depreciation	0.7	0.7	-	-	-	1.4
Depreciation offset	-0.1	-0.1	-0.1	-0.1	-0.1	-0.4
Total	**0.6**	**0.6**	**-0.1**	**-0.1**	**-0.1**	**1.0**

Source: AusNet Services

The total estimated opening RAB value of $1.36 million ($Jun 2021) will be depreciated over 2 years starting from 1 July 2021 under the new asset class '*Accelerated Depr - Distr assets (Other)*'.

The above offsetting depreciation adjustments are contained in our opening RAB depreciation tracking model under the existing asset class '*Distribution system assets*'.

13.8 Forecast depreciation

Based on the depreciation methodology described above, our total forecast economic depreciation for the forthcoming regulatory period is $727.6 million (real $Jun 2021). Depreciation amounts for existing assets, new, accelerated SCADA/Network control assets and decommissioned assets are presented in the table below.

Table 13-18: Forecast Economic depreciation ($m, $Jun 2021)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Existing assets	206.0	197.1	187.7	177.9	168.3	937.0
Accelerated SCADA/Network control assets (pre 2016)	39.7	39.7	39.7	39.7	39.7	198.7
New assets	-	18.3	33.1	48.8	63.0	163.2
Decommissioned assets	1.9	1.9	-	-	-	3.9
Less: indexation on opening RAB	-112.8	-114.4	-115.3	-116.2	-116.6	-575.2
Total	**134.9**	**142.7**	**145.2**	**150.2**	**154.5**	**727.6**

Source: AusNet Services PTRM Model (2022-26)

13.9 Supporting documentation

The following documents are provided in support of this chapter:

- AusNet Services' Depreciation model – '2016-20 AST Proposal Depreciation tracking Model.xlsx';
- AusNet Services' Depreciation model – '2016-21 AST Proposal Depreciation tracking Model.xlsx';
- Spreadsheet entitled "Selected Network SCADA assets opening RAB calculation";

- AusNet Services' AMS 20-72 – Electricity Distribution Network, Protection and Control systems (June 2019);

14 Return on capital and gamma

14.1 Key points

- In December 2018, the AER published its Rate of Return Instrument[158] and an accompanying explanatory statement[159]. As a binding instrument, it sets out the key parameter values and the method that should be applied in estimating the rate of return.
- Our cost of equity and debt have been estimated in accordance with the AER's Rate of Return Instrument. In addition, we have applied the AER's proposed interim measures[160] to address the implementation issues arising from the 6 month extension to the current regulatory period. This comprises the application of the 2018 Rate of Return Instrument and a modification to the trailing average cost of debt.
- Our debt and equity raising costs have been estimated in accordance with the AER's current practice.
- A gamma value of 0.585 has been adopted in accordance with the Rate of Return instrument.
- Our placeholder inflation forecast is 2.45% for the regulatory period commencing 1 July 2021 based on the AER's current approach to estimating forecast inflation. However, we remain concerned that this approach materially overstates expected inflation in the current environment, and therefore encourage the AER to undertake a meaningful, industry-wide, review of its approach as soon as is practicable.

14.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 14.3 provides a brief commentary on the AER's Rate of Return Instrument;
- Sections 14.4 and 14.5 set out our allowed cost of equity and debt for the 2022-26 regulatory period;
- Section 14.6 summarises our estimated weighted average cost of capital (WACC);
- Sections 14.7 and 14.8 present our estimated equity raising and debt raising costs;
- Section 14.9 recaps the role of imputation credits under the post-tax revenue model, and notes the value of gamma adopted for the 2022-26 regulatory period;
- Section 14.10 explains our approach to forecast inflation, which is consistent with the AER's conclusions following its detailed review in 2017; and
- Section 14.11 lists the supporting documents for this chapter.

14.3 Rate of Return Instrument

In November 2018, the National Electricity Law was amended to require the AER to make a binding rate of return instrument.[161] As a binding instrument, it must set out the precise value for

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158 AER, Rate of return instrument, December 2018 (Rate of Return Instrument)., available at: https://www.aer.gov.au/system/files/2018%20Rate%20of%20Return%20Instrument%20%28Version%201.02%29_1.pdf.

159 AER, Rate of return instrument – Explanatory Statement, December 2018, available at: https://www.aer.gov.au/system/files/Rate%20of%20Return%20Instrument%20-%20Explanatory%20Statement.pdf.

160 AER, Victorian Distribution Reset Timing – Proposed Interim Measure, November 2019, available at: https://www.aer.gov.au/system/files/AER%20-%20Letter%20to%20AusNet%20Services%20-%20Reset%20timing%20interim%20measure%20-%206%20November%202019.pdf.

161 National Electricity Law, Part 3, Division 1B.

the rate of return or set out a method for calculating the rate of return that can be applied automatically without exercise of discretion. The AER published its Rate of Return Instrument and an accompanying explanatory statement in December 2018.[162]

The AER's Rate of Return Instrument maintains its long-standing regulatory approach of determining a nominal vanilla weighted average return on equity and debt, weighted by the gearing ratio. The AER's Rate of Return Instrument therefore defines the allowed rate of return as follows:

- k_t = (1-G) x k^e + k_t^d x G
- Where:
- k_t is the rate of return in regulatory year t;
- k^e is the allowed return on equity for the regulatory period and is calculated in accordance with clause 4 of the instrument;
- k_t^d is the allowed return on debt for the regulatory year t, and is calculated in accordance with clause 9 of the instrument; and
- G is the gearing ratio and is set at a value of 0.6.

In accordance with the Rules[163], this chapter sets out our calculation of the allowed rate of return for each regulatory year of the 2022-26 period.

14.4 Return on Equity

The AER's explanatory statement adopts the Sharpe-Lintner CAPM (SLCAPM) to calculate the return on equity. Within the SLCAPM formula, the AER set fixed values for market risk premium and equity beta and establishes a formula for calculating the risk free rate. Clause 4 of the AER's rate of return instrument defines the return on equity as follows:

- k^e = k^f + β x MRP
- Where:
- k^f is the allowed risk free rate of return expressed as an effective annual rate percentage;
- β is the allowed equity beta and is set to a value of 0.6; and
- MRP is the allowed market risk premium and is set to a value of 6.1% per annum.

As the values of the equity beta and market risk premium have been set by the AER's rate of return instrument, we have adopted these values for the purpose of this Regulatory Proposal in accordance with the requirements of the Rules.

The Rate of Return Instrument requires us to estimate the risk free rate using a formula based on yields on 10-year Commonwealth Government Securities (CGS). The formula requires the risk free averaging period to be:

- over a period of between 20 and 60 business days;
- start no earlier than 7 months prior to the commencement of the regulatory period; and
- finish no later than 3 months prior to the commencement of the regulatory period.[164]

In accordance with the Rate of Return Instrument, we have nominated its averaging periods in a confidential letter to the AER. For the purpose of this Regulatory Proposal, it is only possible to provide an estimate of the risk free rates that will apply in the respective nominated averaging

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162 Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018.

163 National Electricity Rules, S6.1.3(9).

164 AER, Rate of Return Instrument, clause 8.

periods. The AER will update the risk free rates and the resulting cost of equity in its draft and final decisions. In this Regulatory Proposal, we have therefore adopted a risk free rate estimated over 60 business days ending 23 August 2019, which results in a risk free rate of 1.26%.

In accordance with the AER's rate of return instrument, our estimated cost of equity for the purpose of this Regulatory Proposal is 4.92%, as presented in the table below.

Table 14-1: Proposed cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	1.26%	This is a placeholder value reflecting the yield on ten year Commonwealth bonds measured over the 60 business day period ending 23 August 2019. The risk free rate for the AER's final determination will be measured over the nominated periods selected in accordance with clause 8 of the AER's rate of return instrument.
Equity beta	0.6	This value is consistent with clause 4(b) of the AER's rate of return instrument.
Market risk premium	6.1%	This value is consistent with clause 4(c) of the AER's rate of return instrument.
Cost of equity	4.92%	The cost of equity is estimated in accordance SLCAPM, as specified in clause 4 of the AER's Rate of Return Instrument.

14.5 Cost of Debt

The AER explains that its approach to estimating the cost of debt comprises the following key elements:[165]

- a benchmarking approach, based on debt yield data from third party data providers and benchmarks for term of debt and credit rating;
- a 10-year trailing average approach with an annual update; and
- a 10-year transition to the 10-year trailing average approach, noting that where a transition has commenced in a previous determination, the AER will continue that transition.

In the AER's final decision for our 2016-20 period, the AER adopted an 'on-the-day' approach for the first regulatory year and commenced a 10-year transition to a trailing average approach, which operates as follows:

- for 2016, the estimated cost of debt reflected the prevailing market rates near the commencement of the 2016-20 regulatory period; and
- or each subsequent year, 10% of the return on debt is updated to reflect the prevailing market conditions in that year.

In accordance with the AER's regulatory instrument, this transitional approach has been maintained for the forthcoming regulatory period. The only complicating factor relates to the six month extension to the current regulatory period, which affects the operation of the transition to the trailing average. Following discussions with the AER, we have adopted a simple adjustment

165 Ibid.

to the transitional approach to accommodate the six month extension. This is set out in Appendix 1C – Extension Period Revenues (1 January – 30 July 2021).

For the purpose of this Regulatory Proposal, the average placeholder portfolio cost of debt is 4.39%, incorporating a placeholder prevailing cost of debt of 3.48%.[166] The return on debt will be updated in accordance with AER's Rate of Return Instrument, reflecting:

- The average of data published by Bloomberg, the Reserve Bank of Australia and Thomson Reuters on the annualized yield on ten year BBB+ rated corporate debt calculated over the nominated averaging period, which will be selected in accordance with paragraphs 23 and 24 of the rate of return instrument.
- The historic cost of debt allowances over the proceeding years, which includes the 'on the day' rate for regulatory year 2016 of 5.52%.

The table below shows the estimated cost of debt over the 2022-26 regulatory period, in accordance with the AER's preferred transition to the trailing average approach. The data shown in the table below will be updated to reflect the prevailing cost of debt each year and for the nominated averaging period for regulatory year 2021.

Table 14-2: Estimated benchmark cost of debt

	2021-22	2022-23	2023-24	2024-25	2025-26
Nominal pre-tax return on debt	4.79%	4.59%	4.39%	4.18%	3.98%

14.6 Nominal vanilla WACC

The table below summarises the calculation of the nominal vanilla WACC or the 'allowed rate of return', in accordance with clause 3 of the Rate of Return Instrument. The table shows that the application of the AER's approach would result in a WACC of 4.84% for 2021-22, reducing to 4.35% by 2025-26.

166 Based on a placeholder averaging period of 12 to 30 November 2018.

Table 14-3: Estimated nominal vanilla WACC

	2021-22	2022-23	2023-24	2024-25	2025-26
Return on equity	4.92%	4.92%	4.92%	4.92%	4.92%
Nominal pre-tax return on debt	4.79%	4.59%	4.39%	4.18%	3.98%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	4.84%	4.72%	4.60%	4.48%	4.35%

The allowed rate of return will be updated in the AER's draft and final decisions and then annually to reflect movements in the cost of debt.

14.7 Equity Raising Costs

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. Accordingly, the AER provides a benchmark allowance to reflect the efficient costs of raising equity, if equity raising is required to maintain the benchmark gearing of 60%.

Our equity raising costs are derived from the PTRM and the AER's benchmarking approach, which includes a distribution rate of 0.9, consistent with the Rate of Return Instrument. Our modelling indicates that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2022-26 regulatory period.

14.8 Debt Raising Costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

The AER provides a benchmark allowance for debt raising costs as a component of our operating expenditure allowance. The AER's approach is based on a report from the Allen Consulting Group, commissioned by the ACCC in 2004.[167] The AER subsequently updated Allen Consulting Group's analysis to reflect more recent market data provided by PricewaterhouseCoopers during the 2013 rate of return guideline process.[168]

In this Regulatory Proposal, we have calculated a debt raising cost allowance based on the AER's recent approach to setting benchmark debt raising costs. This benchmark has been derived as set out in the table below.

[167] Allen Consulting Group, Debt and Equity Raising Transaction Costs, December 2004.

[168] PWC, Energy Networks Association: Debt financing costs, June 2013.

Table 14-4: Debt Raising Costs (bppa)

	Upfront Cost	1 Bond Issues	11 Bonds Issued
Amount Raised		$250m	$2,750m
Arrangement fee		7.22	7.22
Bond master program	$56,250	0.29	0.03
Issuers Legal Counsel	$15,265	0.08	0.08
Company Credit Rating	$77,500	0.40	0.04
Annual surveillance fee	$35,500	0.18	0.02
Up front issuance fee	5.2bp	0.72	0.72
Registration up-front	$20,850	0.11	0.01
Registration annual	$7,825	0.04	0.04
Annual out-of-pockets	$3,000	0.02	0.02
Total (bppa)	**n/a**	**9.05**	**8.16**

The AER recently revised its approach to estimating debt raising costs in its recent Draft Decision for SA Power Networks, based on a report produced by Chairmont.[169] As this updated approach is still part of an active review, we have not adopted it here. We share the concerns raised over the analysis contained in Chairmont's report with SA Power Networks, particularly regarding the derivation of benchmark arrangement fees.

As part of its review, the AER requested actual debt raising cost data from the networks as part of its assessment. We provided this information to the AER in November 2019 and this may impact its Draft Decision on debt raising costs. If so, we will respond to this in our Revised Revenue Proposal.

The resulting benchmark allowance is included in our operating expenditure forecasts, which are set out in Chapter 10.

14.9 Imputation Credit Value (Gamma)

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER takes account of the value of imputation credits (known as gamma or 'γ') to recognise that imputation credits benefit equity holders, in addition to any dividends or capital gains they receive.

As the regulatory framework applies a post-tax WACC, the value of imputation credits is not a WACC parameter. Instead, the value of imputation credits is a direct input into the calculation of

169 Chairmont, Debt Raising Costs, 29 June 2019.

a network service provider's benchmark tax allowance. In accordance with the AER's rate of return instrument, we have adopted a value for imputation credits of 0.585.

The calculation of our benchmark tax allowance for the 2022-26 regulatory period is provided in Chapter 15.

14.10 Forecast inflation

Our forecast inflation is 2.45% for the 2022-26 regulatory period, which will be updated in the AER's draft and final decisions. This forecast is based on the AER's approach to estimating the average annual rate of inflation expected over a ten year period, which reflects:

- the RBA's inflation forecasts for the first two years of the relevant regulatory period, which is the limit of this forecast series; and
- the mid-point of the RBA's target band for inflation (currently 2.5%) to extend the series out to ten years.

The placeholder value adopted reflects that applied by the AER in its latest decision for Jemena Gas Networks (NSW) 2020-25 Access Arrangement Period[170]. It will be updated prior to the AER's final determination to incorporate the relevant updated RBA data.

This forecasting approach is consistent with the AER's historical regulatory practice and its review of the regulatory treatment of inflation in December 2017[171].

As has been submitted to the AER by individual businesses and Energy Networks Australia (ENA), the AER's current inflation forecasting approach continues to produce forecasts that are materially below market expectations, with no sign that this will reverse in the short term. As the AER's methodology is heavily weighted towards the mid-point of the RBA's target inflation band (2-3%), the AER's estimate of inflation remains close to 2.5%, while market based estimates have been at 2% or below since the AER's last inflation review in 2017 – dropping to 1.3% in late 2019. This discrepancy has materially reduced revenues for networks compared to the revenues the framework is targeted to deliver.

While the AER reviewed its approach in 2017, since the review inflation expectations continue to be consistently below the results of the AER's forecasting approach. As such, we strongly support another review of the AER's inflation approach, which aims to amend the AER's methodology to adopt one which leads to a forecast of inflation that is commensurate with the expectations of market participants, and therefore appropriately adjusts the nominal rate of return set by the 2018 Rate of Return Instrument.

While a placeholder based on the AER's approach has been applied in this Revenue Proposal, we continue to have significant concerns with the AER's continued application of its current methodology to setting expected inflation. Inflation outcomes have been well below the RBA's target band for more than 5 years. There is no indication that inflation is expected to increase to be within the target range in the near future.

As the AER's current forecasting approach is heavily weighted to deliver the mid-point of the RBA's target band, the current low inflation expectations are not being appropriately reflected in the AER's inflation forecast.

This was raised in our previous distribution revenue determination process. The AER completed a review of expected inflation in 2017 and concluded that its existing approach was appropriate. However, since then inflation expectations have remained at historic lows, further increasing the evidence base that a change of methodology is warranted.

170 AER, Draft Decision – Jemena Gas NSW, 25 November 2019.

171 AER, Regulatory Treatment of Inflation, Final Position, December 2017.

As forecasting inflation is an industry-wide issue, we will continue to engage in any developments at the industry level and consider any changes as part of our Revised Regulatory Proposal.

14.11 Supporting documentation

The following documents are provided in support of this chapter:

- Appendix 14A – Rate of Return Averaging Periods (confidential); and
- Rate of Return Build up model.

15 Corporate Tax Allowance

15.1 Key points

The AER has implemented its findings from its recent tax review. This chapter explains the key changes which affect the final calculation of the tax allowance building block post 30 June 2021.

We have maintained the weighted average remaining life approach for depreciation of the Opening Tax Asset Base commencing from 1 January 2021.

We explain the basis of our forecast of immediately deductible expenditure for the period 1 July 2021 to 30 June 2026, being a new requirement under the AER's revised tax approach.

15.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 15.3 discusses the AER's Final Report on its review of its regulatory approach to setting the tax allowance;
- Section 15.4 explains the method for calculating the tax allowance;
- Section 15.5 calculates the opening Tax Asset Base (TAB) as at 1 January 2021;
- Section 15.6 presents the standard tax lives and remaining lives which are used to calculate tax depreciation;
- Section 15.7 presents our forecast of immediately deductible expenditure for the 2022-26 regulatory period;
- Section 15.8 sets out the proposed tax allowance; and
- Section 15.9 lists the supporting documents for this chapter.

15.3 AER's Review of the tax allowance

The corporate income tax allowance is an input into our revenue requirement, allowing us to recover an estimate of the corporate tax liability an efficient distributor would incur as a result of the provision of standard control services.

The AER has undertaken a review of the approach for assessing the regulatory tax allowance for service providers following consultation with the ATO on actual tax payments made by businesses and the reasons for some of the differences.

The AER published a new version 4 of the Post Tax Revenue Model (PTRM) in April 2019 which implements the changes made its final report of the tax review. Specifically, the AER made two changes which affect the calculation of tax depreciation in the PTRM:

- **Immediate expensing of capex** – allows for inputs of certain capex to be immediately expensed when estimating the benchmark tax expense.
- **Diminishing value depreciation method** – applies diminishing value method for tax depreciation purposes to all new depreciable assets except for capex associated with in-house software, equity raising costs and buildings.

The above changes take effect from 1 July 2021 for the Victorian Distribution businesses. We have populated the latest version of the PTRM (Version 4) with the data presented in this Regulatory Proposal.

15.4 Method for calculating the tax allowance

15.4.1 Overview

The AER's post-tax revenue model (PTRM) calculates a DNSP's tax allowance in accordance with clause 6.5.3 of the National Electricity Rules (NER). Specifically, the PTRM calculates the tax allowance (or the tax building block) by:

1. Deducting tax expenses (opex, interest payments on debt and total tax depreciation for all assets) from required revenue (including income from customer contributions) to arrive at the DNSP's taxable income; and
2. Multiplying taxable income by the corporate income tax rate, then multiplying the result by one minus the utilisation of imputation credits (gamma).

This calculation is represented by the following equation in clause 6.5.3:

$$ETC_t = (ETI_t \times r_t)(1 - \gamma)$$

where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the value of imputation credits.

15.4.2 Inputs to the calculation of the tax allowance

The method for calculating our tax allowance for the 2022-26 regulatory period requires the following inputs, including one new input:

- opening tax asset base (TAB) as at 1 July 2021;
- remaining tax lives;
- standard tax lives;
- the company income tax rate;
- the value of gamma;
- any accumulated tax losses as at 1 July 2021; and
- a forecast of immediate expensed (for tax purposes) capex for the 2022-26 period.

Each of these inputs is discussed in the following sections.

15.5 Opening tax asset base

The following table shows the roll forward of the TAB using actual and forecast net capex and depreciation. Net capex for regulatory years 2019, 2020 and 6 months to June 2021 are forecasts only and we will update our 2019 net capex with actuals as part of our Revised Regulatory Proposal.

Table 15-1: Tax Asset Base roll forward to 1 January 2021 ($m nominal)

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Opening TAB	2,191.8	2,403.8	2,649.8	2,942.4	3,278.3	3,594.2
Plus capex, net of disposals	311.7	358.2	411.9	457.9	469.4	222.3
Less straight line depreciation	-99.6	-112.2	-119.4	-120.9	-150.5	-87.7
Closing TAB	**2,403.8**	**2,649.8**	**2,942.4**	**3,278.3**	**3,594.2**	**3,732.8**

Source: AusNet Services' Proposal Roll Forward Model (2016-21).

For the TAB roll forward from 1 July 2021 we have continued using the WARL approach and consequently the straight-line depreciation calculations are based on the remaining lives contained in the PTRM opening TAB inputs (and as detailed below in section 15.5.3).

15.5.1 Final year asset adjustments

We are proposing several end of period asset adjustments to both RAB and TAB. These adjustments are described in Chapter 13 – RAB, Section 12.5. The corresponding TAB adjustments are shown in the Table below.

Table 15-2: Proposed Final Year Asset Adjustments (30 June 2021), $Nominal

RAB class	Proposed TAB adjustments ($M)	Remaining life of adjustments to TAB (Yrs)
Sub-transmission	-34.9	28.5
Distribution system assets	-87.2	26.2
* *Secondary systems – pre 2016*	122.0	5.3
Accelerated Depr - Distr assets (Contingent Project 1)	-	-
Accelerated Depr - Distr assets (Contingent Project 2)	-	-
Accelerated Depr - Distr assets (Contingent Project 3)	-	-
* *Accelerated Depr - Distr assets (Other)*	-	-
Subtotal ($Nominal)	**-**	

Source: AusNet Services' Roll Forward Model (2016-21).

** Denotes the new asset classes proposed by AusNet Services. Further information about these classes is contained in section 13.6 of the Depreciation Chapter.*

15.5.2 Opening TAB values for network SCADA assets

We have also undertaken a calculation to estimate the 1 July 2021 opening value in the sunk tax asset base for these network SCADA assets. As shown in Table 15-3 below we have estimated the opening TAB value to be $122.0 million ($Nominal) with a remaining life of 5.3 years (equivalent to the calculated RAB remaining life). We are proposing to transfer this amount into the new class '*Secondary systems – pre 2016*' as reflected in the forecast final year asset adjustments section of our RAB roll forward model.

It should be noted that up until January 2016 the diminishing value method of depreciation was applied to our TAB, in accordance with the previous ESC approach. Our calculation therefore recognises this and draws upon the approved 2015 closing TAB values and remaining lives information contained in the Final Decision on our roll forward model for the 2011-15 regulatory period.[1]

Table 15-3: Estimated Opening TAB for network SCADA as at 1 July 2021

Asset type	Asset Class	Estimated Opening TAB value ($m)	Average Remaining life (Yrs)	Recalculated Average Remaining life (Yrs)
IED protection relays 66 kV	Sub-transmission	34.9	28.5	6.6
IED protection relays < 66 kV	Distribution system assets	69.8	26.2	5.7
Remote Terminal Units	Distribution system assets	17.4	26.2	5.8
Total / Weighted Average		**122.0**	**26.8**	**5.3**

Source: AusNet Services.

The opening TAB values were determined by taking the estimated 2016 opening RAB values (from Table 13-12 in Chapter 13 – Depreciation) and determining the relative proportions of the total 2016 opening RAB value in each existing asset class. The total 2016 opening RAB values were sourced from the 2011-15 Final Decision roll forward model.[2] These proportions were then multiplied by the respective total 2016 opening TAB values to derive the 2016 opening TAB values. This is a reasonable approach for estimating the initial opening TAB values in the absence of a disaggregated historical tax asset model which incorporates the diminishing value approach. The calculated 2016 opening values were then rolled forward to July 2021 using straight-line depreciation in accordance with the AER's standard approach for the 2016-20 period.

Further details on this calculation including the remaining tax lives are contained in supporting attachment 'Opening TAB adjustments.xlsx'.

1 AER - Final decision AusNet Services - Roll forward model - May 2016.xlsx.

2 Ibid.

15.5.3 Remaining tax lives

The remaining lives for assets contained in the 1 July 2021 opening TAB are presented below. This includes a portion of Metering related IT capex which is captured under standard control services in the current period.

Table 15-4: Opening TAB remaining tax lives

Asset class	Remaining life (Yrs)
Sub-transmission	36.4
Distribution system assets	35.1
SCADA/Network control	8.2
Non-network general assets – IT	3.0
Non-network general assets – Other	8.3
Land	n/a
Non-network - Metering related IT	2.3
Non-network Leasehold Land & Buildings – 1 Apr 2019	9.2
Non-network Leasehold Land & Buildings – CY2020	20.0
Non-network Leasehold Land & Buildings – Jan-Jun 2021	8.0
Equity raising costs – Jan-Jun 2021	5.0
Equity raising costs	0.5

Source: AusNet Services' Roll Forward Model (2016-21).

As part of our proposed forecast final year asset adjustments in the roll forward model, the following additional asset classes have been created in the PTRM.

Table 15-5: Additional asset classes

Asset class	Remaining tax life (Yrs)
Secondary systems (pre-2016)	5.3
Accelerated Depr - Distr assets (Contingent Project 3)	n/a
Accelerated Depr - Distr assets (Other)	n/a

Source: AusNet Services.

15.6 Standard Tax Lives

At the commencement of the 2016-20 regulatory period we adopted the standard tax lives set out in ATO Tax Ruling 2014/4 (TR 2014/4) to assign standard lives to each tax asset class. The AER approved the standard tax lives as part of our transition away from maintaining tax depreciation schedules that used ESC tax categories and the diminishing value approach up until 2015. This process resulted in the standard tax lives shown in the table below.

Table 15-6: Standard Tax Lives for 2016-20 period

Asset class	Standard life (Yrs)
Sub-transmission	43.0
Distribution system assets	46.0
SCADA/Network control	10.0
Non-network general assets – IT	4.0
Non-network general assets – Other	12.0
Land	n/a
Equity raising costs	5.0

Source: AusNet Services Proposal Roll Forward Model.

The historical mapping of ATO tax asset lives into the RAB and TAB asset classes set out above is contained in Appendix 16A of our 2016-20 Regulatory Proposal.[3]

15.6.1 Proposed Standard lives

Our proposed standard tax lives for new additions in the forthcoming regulatory period (2022-26) (presented in Table 15-7 below) are unchanged from the current period. These proposed standard tax lives reflect the tax lives contained in the ATO's latest tax ruling (TR 2018/4) with the exception of capitalised leasing assets which align with their respective proposed standard RAB lives. For Non-network – Metering related IT assets, we propose a standard life of 3 years consistent with the approved standard life for the current regulatory period.

[3] AST, Electricity Distribution Price Review 2016–20 – Appendix 16A: Tax Standard Lives, 30 April 2015.

Table 15-7: Proposed Standard Tax Lives for new additions

Asset class	Standard life (Yrs)	DV rate (200%)
Sub-transmission	43.0	4.7%
Distribution system assets	46.0	4.3%
SCADA/Network control	10.0	20.0%
Non-network general assets - IT	4.0	50.0%
Non-network general assets - Other	12.0	16.67%
Non-network - Metering related IT	3.0	66.67%
Land	n/a	n/a
Non-network Leasehold Land & Buildings – 1 July 2021 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2021-22 *	23.7	n/a
Non-network Leasehold Land & Buildings – 2022-23 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2023-24 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2024-25 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2025-26 *	5.0	n/a
Buildings	40.0	n/a
In-house software	4.0	n/a
Equity raising costs	5.0	n/a
Equity raising costs 1 Jan – 30 June 2021	5.0	n/a

Source: AusNet Services.

Six new asset classes have been established in the Proposal PTRM in relation to forecast capitalised leasing costs for the 2022-26 period. These capitalised lease costs relate to changes in Australian accounting standards. Further information about these changes are contained in Appendix 9E.

Two new asset classes 'Buildings' and 'In-house software' have been required to implement the findings of the AER's 2018 Tax Review. The standard tax lives of these assets are 40 and 4 respectively, which reflect Australian Tax Law.

15.7 Forecast of immediately deductible expenditure

Table 15-8 below contains our forecast of immediate deductible capital expenditure for the 2022–26 regulatory period as provided in the PTRM (Version 4) that is submitted as part of this Regulatory Proposal. For tax purposes, all replacement expenditure as well as capitalised indirect labour is treated as immediately deductible capital expenditure.

Table 15-8: Forecast immediately deductible expenditure 1 July 2021 to 30 June 2026 ($m Jun $2021)

Asset Class	2021-22	2022-23	2023-24	2024-25	2025-26
Sub-transmission	26.7	33.9	33.7	21.4	10.3
Distribution system assets	103.4	97.5	98.0	109.5	124.5
SCADA/Network control	13.8	12.5	12.1	13.0	9.0
Non-network – ICT	2.4	2.4	2.4	2.4	2.4
Non-network - Other	0.7	0.7	0.7	0.7	0.7
Total	**147.0**	**147.0**	**147.0**	**147.0**	**147.0**

Source: Immediately expensing capex forecast FY22-26.

Our forecasting approach uses an historical average of actual reported information contained in our annual tax returns. The value of immediately deductible expenditure is inherently difficult to forecast given that our actual values reported in the annual tax returns are on an 'as-commissioned' basis. By their nature, the annual value of these expenditures fluctuate year on year and for this reason our approach uses a 4 year historical average (including tax years 2015-16, 2016-17, 2017-18 and 2018-19). We have escalated the nominal annual amounts into real $2021 before calculating the average of $147.0 million per year. The disaggregation into RAB asset classes follows the allocations of replacement expenditure in our 2022-26 capex forecast model.

On a like-for-like basis it is expected that immediately deductible capex incurred over this historical period reflects the proportion of capex likely to be immediately deductible in the forecast period, for standard control services. This is because replacement expenditure – the majority of which has previously been treated as immediately deductible for tax purposes – as a proportion of total capital expenditures in both the current regulatory control period and the next period (starting 1 July 2021) is very similar. Information sourced from annual financial RIN submissions showed that on average our actual replacement expenditure across regulatory years 2016 to 2018 represents 34% of total gross capex. By comparison, forecast replacement expenditures in the 2022-26 period are on average 35% of total gross capex. We made some adjustments to ensure a like-for-like comparison, i.e., by removing forecast SCS Metering Comms replacement costs from total forecast replacement costs in the 2022-26 period (since these metering costs are not present in the current period under standard control services). These metering related costs are also not subject to immediate deductions for tax purposes.[4] A detailed breakdown of the forecast is provided in the attached supporting model 'Immediately expensing capex forecast FY22-26'.

Our approach of using historical average annual tax deductions is therefore a reasonable proxy for the level of immediately deductible expenditure incurred in the 2022-26 period.

Moving forward, we do not intend to change our tax policy on immediate expensing capital expenditure from current policy for our electricity distribution business.

4 In accordance with AusNet Services' annual tax returns for its metering business.

15.8 Proposed tax allowance

Below is our forecast TAB roll forward for the forthcoming regulatory period. We observe that the tax depreciation charge increases substantially compared to the current period, mainly as a result of immediately deductible expenditure and diminishing value approach applied to new additions.

Table 15-9: Tax Asset Base roll forward to 30 June 2026 ($m nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening TAB	3,732.8	3,814.8	3,858.4	3,895.5	3,941.6
Plus capex, net of disposals and capital contributions	318.2	309.1	316.5	307.7	316.9
Plus capital contributions	74.1	73.9	74.0	77.0	79.9
Less tax depreciation	-310.4	-339.5	-353.4	-338.5	-358.1
Closing TAB	**3,814.8**	**3,858.4**	**3,895.5**	**3,941.6**	**3,980.4**

Source: AusNet Services' Proposal PTRM Model.

We have assumed a company income tax rate of 30% for the 2022-26 period and have applied a diminishing value multiplier of 200% for new additions post 30 June 2021. As already noted, we have used 58.5% for the value of gamma in accordance with the AER's 2018 rate of return instrument[5].

We confirm that, consistent with the information contained in the current period decision PTRM, including the 1 January - 30 June 2021 PTRM, we will have no accumulated tax losses as at 1 July 2021. Our forecast of the tax allowance for the 2022-26 period is contained in Table 15-10 below.

Table 15-10: Proposed Tax Allowance 1 July 2021 to 30 June 2026 ($m nominal)

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26
Tax Payable	-	-	-	-	-
Imputation credits	-	-	-	-	-
Tax Allowance	**-**	**-**	**-**	**-**	**-**

Source: AusNet Services' Proposal PTRM Model.

15.9 Supporting documentation

The following document is provided in support of this chapter:

- Opening TAB adjustments.xlsx
- Immediately expensing capex forecast FY22-26

5 AER, 2018 rate of return instrument, December 2018, p. 19.

16 Incentive schemes

16.1 Key points

This chapter describes our proposed approach to the national and jurisdictional incentive schemes that will apply in Victoria during the forthcoming regulatory period including the:

- Service Target Performance Incentive Scheme (STPIS);
- Guaranteed Service Level (GSL) Scheme;
- F Factor scheme;
- Demand Management Incentive Scheme (DMIS) and Demand Management Innovation Allowance (DMIA);
- Efficiency Benefit Sharing Scheme (EBSS); and
- Capital Efficiency Sharing Scheme (CESS).

The targets and outcomes from these incentive schemes are fundamentally interlinked to our expenditure proposals as both are an input to and output from the company's asset management strategy and the work programs that underpin this proposal. Our capex and opex proposals are outlined in Chapters 9 and 10 respectively. We have a strong record of delivering lower operating costs and improved service levels in response to the incentive framework it operates under. Therefore, the AER's stated intention[1] to apply the full suite of incentives in Victoria is fully supported.

16.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 16.3 provides important background to our current performance and stakeholder views, including the input of the Customer Forum;
- Section 16.4 explains the proposed customer satisfaction incentive scheme, which has been developed with the assistance and input from the Customer Forum;
- Section 16.5 sets out our STPIS proposal, including GSL threshold performance levels and payments;
- Section 16.6 explains the GSLs;
- Section 16.7 explains the F Factor scheme;
- Section 16.8 explains our DMIS and DMIA proposal;
- Section 16.9 presents our EBSS proposal;
- Section 16.10 explains our CESS proposal; and
- Section 16.11 lists the supporting documents for this chapter.

16.3 Recent performance and stakeholder feedback

We strongly support the AER's incentive regime. The framework's constituent schemes align the distributors' incentives to achieve efficient price and non-price outcomes with the long-term interests of consumers, consistent with the National Electricity Objective (NEO). The objectives

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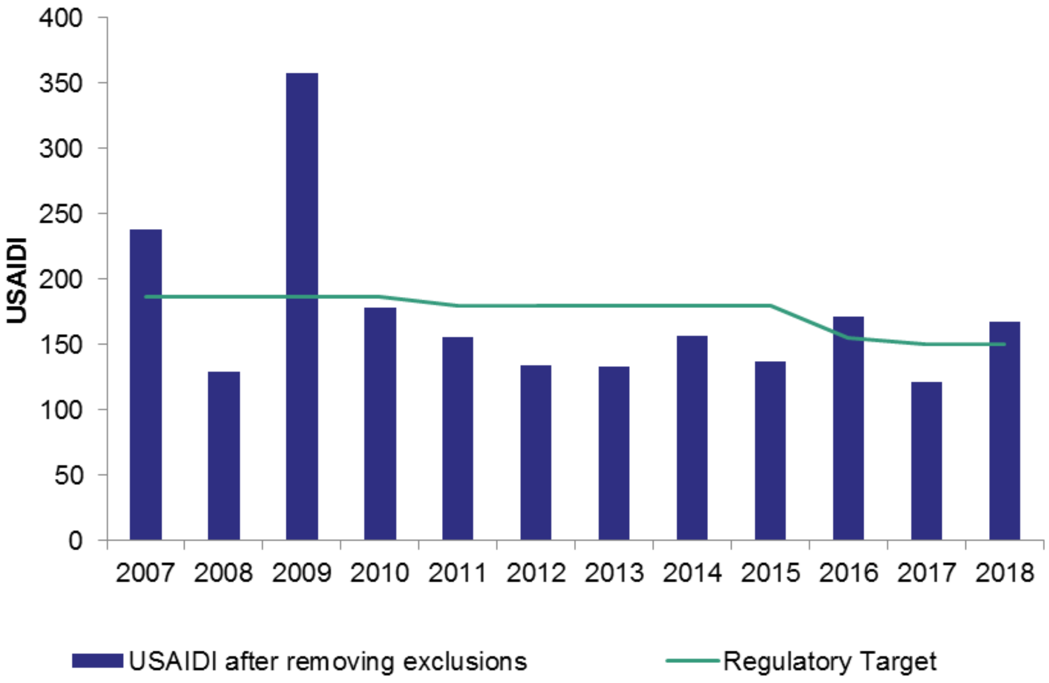
[1] Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy - Regulatory control period commencing 1 January 2021 - January 2019.

and benefits of the incentive framework is demonstrated by our performance under the current period's various incentive schemes.

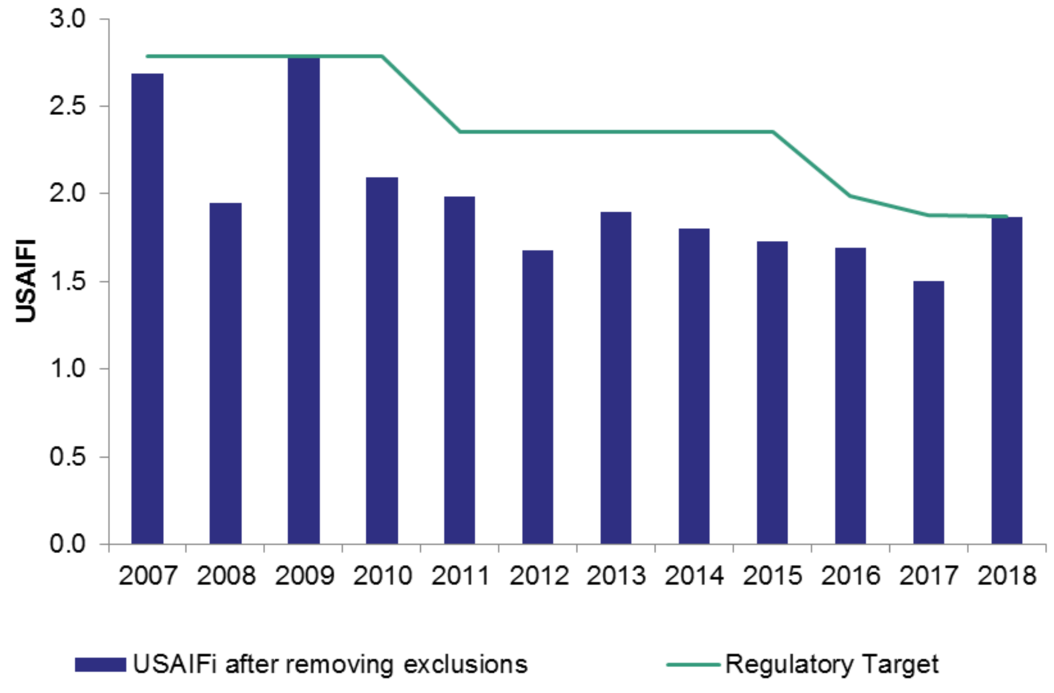
We have a long term improving trend of reliability performance, driven by a continued focus on the incentives provided by the STPIS. In recent years, our reliability performance has been mixed. In 2017 our reliability performance was the best on record, while 2016 and 2018 were years of poorer than average reliability. As the targets for reliability under the STPIS have become successively harder, it is becoming more difficult to outperform these targets year-on-year.

Figure 16-1: Average minutes off supply per customer (USAIDI)



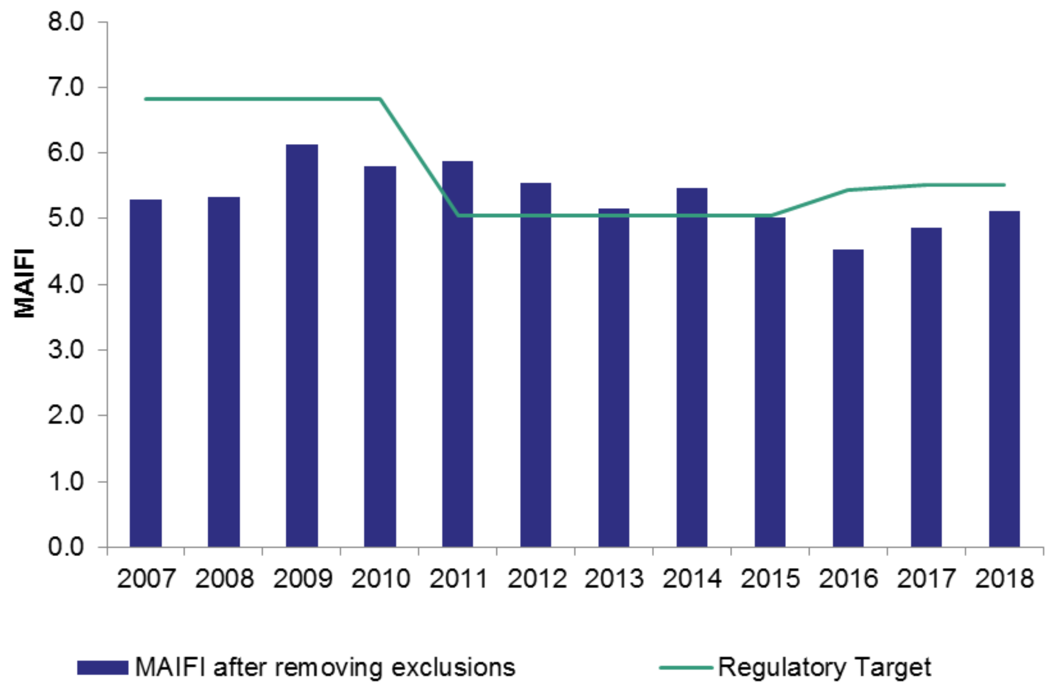
Source: AusNet Services.

Figure 16-2: Average number of unplanned interruptions per customer (USAIFI)



Source: AusNet Services.

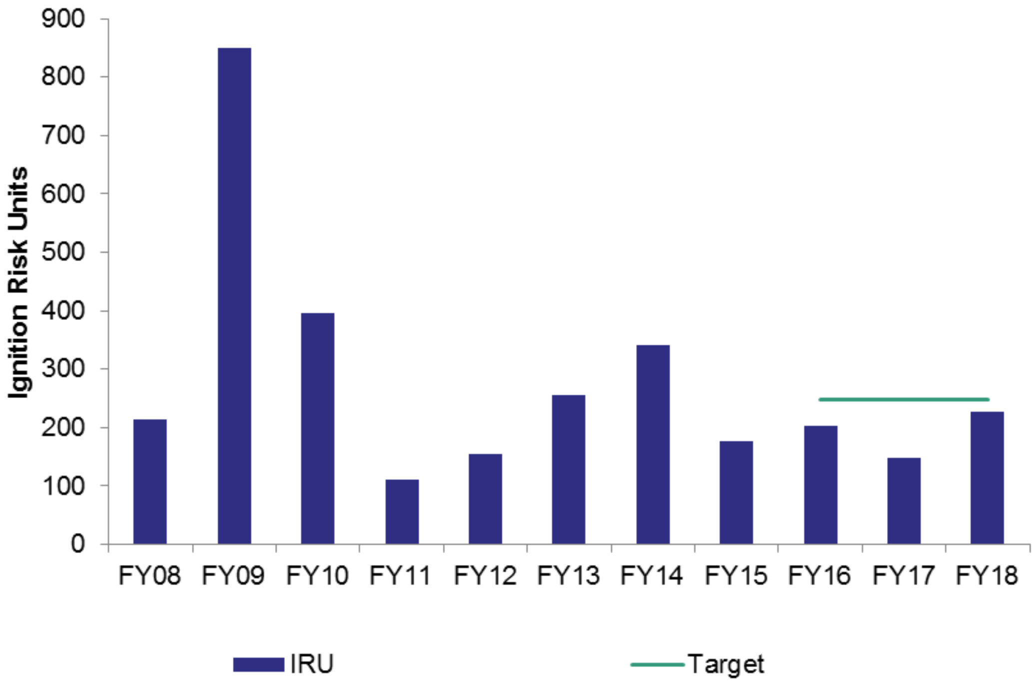
Figure 16-3: Average number of momentary interruptions per customer (UMAIFI)



Source: AusNet Services.

In relation to the f factor scheme, we have experienced a considerable fall in its Fire Risk and has outperformed the Ignition Risk Units targets each year since they were incorporated into the F-Factor Scheme.

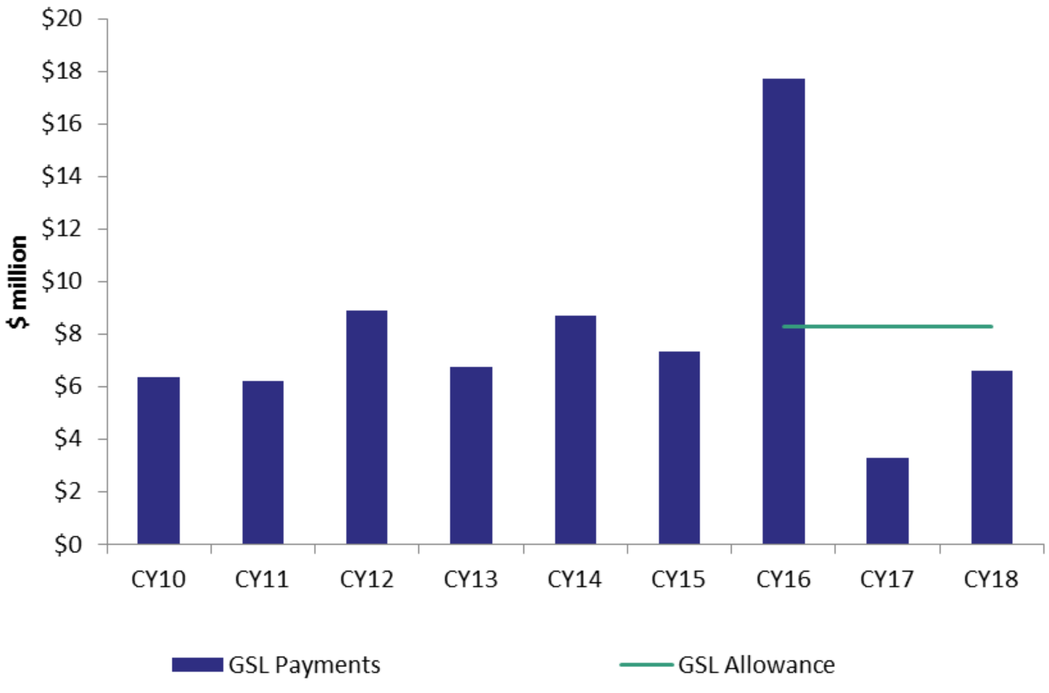
Figure 16-4: F-Factor IRU's



Source: AusNet Services.

We are subject to a Victorian GSL scheme which is contained in the Electricity Distribution Code, administered by the Victorian Essential Services Commission. GSL payments have been highly volatile, which is expected as they are primarily driven by large, and infrequent, outage events. In 2016 severe storms drove a very high amount of GSL payments (over $10 million from the one event). In 2017, the best year of reliability on record, very low GSL payments were made, with a return to a more typical level of payments in 2018. This GSL scheme was revised for the beginning of 2016 and the thresholds were made harder than the previous scheme. Our performance in 2017 and 2018 are very favourable when viewed against this background.

Figure 16-5: GSL Payments



Source: AusNet Services.

16.4 Customer Satisfaction Incentive Scheme

The AER has begun consultation on a small scale incentive scheme, at the request of AusNet Services, under clause 6.6.4 of the NER. The AER published a draft Customer Satisfaction Incentive Scheme (CSIS) on 17 December 2019. We support the draft scheme and propose to apply the resulting scheme in the 2022-26 regulatory period.

This scheme has been developed as part of the 'New Reg' process, to enhance our incentive to place a greater focus on the meeting the needs of our customers. The existing telephone answering parameter (contained in the STPIS) does not adequately address the broad needs and preferences of our customers. We consider that a more holistic incentive scheme should be applied instead.

The proposed scheme has been agreed with the Customer Forum, which considers it to be a significant improvement on the existing arrangements. We engaged in extensive consultation with the Customer Forum and the Customer Forum provided a supporting submission to our proposal, where they commented:[2]

> *We tested our view on the limitations of the existing CSIS and benefits of enhancement with community advocates at a meeting on 18/8/2018. Support was expressed by representatives of attending organisations: Vinnies, SACOSS & PIAC.*
>
> …
>
> *We further tested the view at Deep Dive session on 11/2/19. Reps included VCOSS, RDV, ECA, MEU & CCP. No objection to enhancing the scheme was voiced.*

We note that consultation on the final form of the scheme is ongoing and any revisions in the AER's final decisions may necessitate changes to this proposal.

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2 Customer Forum - Briefing Note for Customer Service Incentive Scheme - 27 March 2019.pdf.

16.4.1 Regulatory Requirements

Clause 6.6.4 of the NER allows the AER to develop a small scale incentive scheme. It states:

> (a) The AER may, in accordance with the distribution consultation procedures, develop and publish an incentive scheme or schemes (small-scale incentive scheme) that provides Distribution Network Service Providers with incentives to provide standard control services in a manner that contributes to the achievement of the national electricity objective.
>
> (b) In developing and applying a small-scale incentive scheme, the AER must have regard to the following matters:
>
> > (1) Distribution Network Service Providers should be rewarded or penalised for efficiency gains or losses in respect of their distribution systems;
> >
> > (2) the rewards and penalties should be commensurate with the efficiency gains or efficiency losses in respect of a distribution system, but a reward for efficiency gains need not correspond in amount to a penalty for efficiency losses;
> >
> > (3) the benefits to electricity consumers that are likely to result from efficiency gains in respect of a distribution system should warrant the rewards provided under the scheme, and the detriments to electricity consumers that are likely to result from efficiency losses in respect of a distribution system should warrant the penalties provided under the scheme;
> >
> > (4) the interaction of the scheme with other incentives that Distribution Network Service Providers may have under the Rules; and
> >
> > (5) the capital expenditure objectives and the operating expenditure objectives.

We have designed our proposed Customer Satisfaction Incentive Scheme (CSIS) to satisfy the requirements of the NER and to promote the National Electricity Objective (NEO). We consider our negotiation with the Customer Forum and the broad canvassing of this scheme demonstrates significant customer support for our proposed scheme. Furthermore, our proposed scheme is consistent with the AER's Scheme Objectives. Each of the matters the AER must have regards to, and the reason we consider the proposed scheme satisfies these requirements, is set out below:

- By providing a more holistic incentive to improve customer satisfaction, we consider the proposed scheme is in the long term interest of consumers and so satisfies the National Electricity Objective.
- Customer Satisfaction is an output of our business and so an improvement in the quality of customer service represents an increase in our efficiency. The CSIS will provide us an incentive to increase expenditure on customer service when the additional inputs are less that the value of the increased output. This represents an overall gain in the efficiency our network.
- The incentive rate was agreed with the Customer Forum on the basis that it would not unduly reward us for an increase in customer satisfaction. We consider these incentive rates ensure the benefits to electricity consumers that are likely to result from efficiency gains in respect of a distribution system should warrant the rewards provided under the scheme.
- There are limited interactions with the AER's existing STPIS, however these limited interactions are not impediments to implementing this customer satisfaction incentive scheme.
    a. We propose that the existing telephone answering parameter should not apply to us in the 2022-26 regulatory period and this removes this interaction with the STPIS.
    b. The STPIS also provides rewards for reductions in the number and duration of unplanned outages. The customer satisfaction incentive scheme will measure customer's satisfaction with the unplanned outages they experience. However,

this does not result in an inappropriate interaction between the two schemes because the two measures should be largely independent.[3]

c. Clause 6.5.7(a)(3)(iii) of the NER allows that building block proposal must include the capital expenditure to maintain the quality, reliability and security of supply of standard control services. Similarly, Clause 6.5.6(a)(3)(iii) of the NER requires that the building block proposal must include the operating expenditure to maintain the quality, reliability and security of supply of standard control services. The proposed CSIS is the appropriate funding mechanism to drive improvements in customer satisfaction.

16.4.2 Proposed application of CSIS

Our proposal for the operation of CSIS is set-out below and accords with the AER's draft CSIS.

16.4.2.1 Performance parameters

We propose that four performance parameters are measured under CSIS. These parameters are:

- Customer Satisfaction – unplanned outages;
- Customer Satisfaction – planned outages;
- Customer Satisfaction – New Connections (Basic and Standard); and
- Customer Satisfaction – Complaints.

These performance parameters are key interactions or experiences that customers have with us. Our decision to adopt these particular parameters was based on consultation undertaken to help understand the areas where customers value improved service delivery. A large number of our customers experience planned or unplanned outages each year, so improvements in these areas have widespread impact. New connections impact a smaller number of customers, but it is a particularly important interaction as delays could slow down a customer when they are seeking to occupy a premises. Similarly, complaints are only made by a small number of customers, but likely reflect a deficiency in our service delivery and so are a high priority interaction for the customers impacted.

The Customer Forum supports the performance parameters chosen and stated that:[4]

> *We were given the opportunity to work through a range of indicators against which AusNet Services performance could be managed. AusNet Services customer research staff advised that the proposed metrics needed sufficient statistical data to allow robust benchmarks to be established. The four metrics ultimately selected for the enhanced scheme - planned outages, unplanned outages, connections and complaints - reflected key areas of concern amongst customers and could, in the Forum's view, be accompanied by robust benchmark data.*

This demonstrates strong support that the parameters selected will deliver value to customers and is consistent with the AER's principles for performance parameters in section 3.2(1) of the draft scheme.

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3 The use of automatic outage restoration technology has been able to reduce the number of customers who experience a sustained outage (as we are able to use switching to restore supply to many customers in under a minute), but does not change (either increase or decrease) the length of the outage for the customers who remain affected (we still need to dispatch a truck to resolve the problem and this response is unchanged by the automatic restoration of some customers).

4 Customer Forum - Briefing Note for Customer Service Incentive Scheme - 27 March 2019.pdf.

Table 16-1: CSIS performance parameter definitions

Scheme Parameter	Definition
Planned Interruptions	A prearranged interruption to supply where affected customers are given advanced notification. This interaction includes both short sustained and general interruptions to customers' electricity supply. A short sustained interruption is typically less than one-hour in duration and is required for maintenance or the upgrading of local assets. They are often scheduled for quick network configuration works or installation of local generators. General, or sustained, interruptions are typically longer than one-hour and are required for maintenance or the upgrading of local assets.
Unplanned Interruptions	An unexpected interruption to supply most commonly caused by trips (i.e., drop out fuse trips, LV fuse trips, recloser trips, feeder trips, sub-transmission trips, sectionaliser trips) and switch isolations. This interaction excludes recloses or interruptions of less than 1 minute under the assumption that the customer affected may not have experienced the outage.
Connections	Basic and standard connections are captured in this interaction. A basic connection includes hanging a meter and energising the premise where network changes or upgrades are not required. A standard connection, on the other hand, does require a network change which might include a new pole installation, line extension or upgrade, pit construction and other technical changes like substation upgrades and making supply available to a site in accordance with customer's load requirements. A standard connection does not include hanging a meter and site energisation. Negotiated or more complex connections that require some bespoke design and planning are excluded from this interaction.
Complaints	An escalated customer dispute that was not deemed to be resolved by a Resolutions Team member.

Source: AusNet Services.

16.4.2.2 Measurement methodology

We commission a monthly telephone survey of our residential and business customers' satisfaction. The results of this ongoing survey, which are reported quarterly, will form the basis of the customer service incentive scheme. This survey is conducted by an independent third party CSBA, which is an industry leader in Customer Experience Research. CSBA has quality assurance processes as per ISO 20252 (Market & Social Research) standards. CSBA will also make the raw data available to both AusNet Services and the AER for validation purposes.

We consider using an independent third party, with relevant quality assurances processes provides sufficient assurance arrangements. However, the data provided will also allow the AER to undertake further independent investigation that it considers necessary.

16.4.2.3 Assesment approach

Targets

We propose fixed performance targets set using the average of the Customer Satisfaction (CSAT) data. Collection of this data commenced in 2018 and is now an ongoing BAU activity. The AER has generally looked to rely upon five years of data in their incentive schemes and we will have less than 5 years of data available at the time the decision is made. We propose to provide updated information in our revised proposal, which will allow for the use of all the data available at the time of the AER's final decision. This means that the targets indicated below will be updated closer to the implementation of the scheme to ensure that they are set on the most recent information. The update to the targets will be able to incorporate customer satisfaction data from 2018, 2019 and half of 2020. We consider this is a sufficiently lengthy historical data set on which to set the targets. At the time of this submission our 'target' for each of these parameters is shown below.[5]

Table 16-2: CSIS scheme targets

Scheme Parameter	Target
Planned Interruptions	7.2 out of 10
Unplanned Interruptions	6.5 out of 10
Connections	6.3 out of 10
Complaints	3.6 out of 10 (with a deadband set at 5, so no reward is received until we achieve this level of performance)

Source: AusNet Services.

We propose that the targets are fixed for each year of the 2022-26 regulatory period.

Evaluating performance against the targets

We propose that on an annual basis the annual performance will be calculated as the average score achieved for each performance parameter. Additionally, we propose performance deadbands are applied to each performance parameter.

Performance deadbands

The Customer Forum expressed concern that we would be rewarded for improving our complaints score off a low baseline. Accordingly, we propose that a deadband is applied to the complaints parameter in the 2022-26 regulatory period. This ensures that we are not rewarded unless we achieved a minimum level of customer satisfaction with the complaints process. We propose that a deadband is set with the lower bound at the performance target and with a higher upper bound. This means that:

- we will face a penalty if customer satisfaction declines below the target level; and
- we will only receive a reward if it achieves a material improvement in customer satisfaction above the target level. This ensures that there is no provided until we have achieved a

5 ASD - CSAT data, targets and reporting template – Public.xls.

minimum level of satisfaction for our customers, which is equal to the upper bound of the dead band.

We have agreed with the Customer Forum that the deadband for the complaints threshold is set at 5 out of 10. This means that we will only receive a reward if performance exceeds a customer satisfaction level of 5. We note that our current performance is 3.6 out of 10 and that industry leading performance is 5.8 out of 10. As such, setting the upper bound of the deadband at 5 represents our commitment to significantly improving in our customers' satisfaction in our complaints handling process.

For the other parameters we have agreed with the customer forum that no reward or penalty will be provided unless the 90% confidence interval is greater or less than the target. This provides statistical confidence that the performance delivered is better or worse than the target. The proposed calculation of the deadbands for each parameter is contained in the proposed annual reporting template.[6]

16.4.2.4 Financial component

We propose that the financial component of the scheme is calculated in accordance with Appendix A of the draft scheme.

Revenue at risk

We propose that 0.5% revenue at risk be applied to the CSIS in the 2022-26 regulatory period. This matches the revenue at risk under the existing telephone answering parameter in the STPIS and ensures that customers are not exposed to an overall greater revenue at risk than under the existing scheme.

The Customer Forum has agreed to this level of revenue at risk and stated:[7]

> *We acknowledged that AusNet Services would face a considerable challenge in moving from a long standing and relatively easy performance measure to four measures. For that reason we agreed that limiting the revenue at risk to 0.5% was advisable.*

Incentive rates

We have agreed with the Customer Forum that the incentive rates in the table below reasonably reflect the reward or penalty that would be valued by customers for a 1 point change in the customers satisfaction. There is a subjective element in the agreement on these rates, but they were considered to be at a level that would not unduly reward us for an increase in customer satisfaction. We note that these incentive rates would require a significant increase (to levels similar to the current benchmark industry performance in customer satisfaction) for the maximum reward to be achieved. We propose these incentive rates are fixed for the forthcoming regulatory period.

6 ASD - CSAT data, targets and reporting template – Public.xls.

7 Customer Forum - Briefing Note for Customer Service Incentive Scheme - 27 March 2019.pdf.

Table 16-3: CSIS incentive rate

Scheme parameter	Indicative reward for a 1 point improvement in satisfaction	Incentive rate (%)
Planned Interruptions	$493,579	0.08%
Unplanned Interruptions	$493,579	0.08%
Connections	$493,579	0.08%
Complaints	$246,789	0.04%

Source: AusNet Services.

16.5 Service Target Performance Incentive Scheme

The national distribution STPIS provides a financial incentive to distributors to maintain and improve service performance. The STPIS ensures that cost efficiencies encouraged under our expenditure schemes are not achieved at the expense of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributors' incentives towards efficient price and non-price outcomes with the long-term interests of consumers, consistent with NEO.

The AER recently reviewed the operation of the STPIS and published its finals decision on version 2.0 of the STPIS in November 2018. Key changes in the revised scheme are:

- The weighting ratio for the STPIS incentive rates was changed from 50/50 SAIFI to SAIDI to 40/60 SAIFI to SAIDI.
- It implemented the AEMC's recommendation to change the threshold for momentary interruptions and momentary interruption events from less than 1 minute to less than 3 minutes.
- Established a threshold for the definition of an urban feeder based on average demand over a three year period and over the average length of that feeder for the period.

We have applied version 2.0 of the STPIS for this regulatory period and made the adjustments necessary to our performance data to ensure consistency with the revised scheme. This required us to recalculate our historical data to ensure it is on the correct basis.

16.5.1 Regulatory Requirements

The STPIS, as it will be applied in Victoria is defined in the following two documents:

- Electricity Distribution Network Service Providers Service Target Performance Scheme Guidelines, released in November 2018 (STPIS Guidelines); and
- The AER's Framework and Approach.

NER S6.1.3(4) requires that a regulatory proposal must contain a description of how the DNSP proposes the STPIS should apply for the relevant regulatory period.

16.5.2 Proposed application of the STPIS

The AER's proposed approach is to continue to apply the national STPIS to the five Victorian electricity distributors in the next regulatory period. The AER completed a review of the STPIS in November 2018 and published Version 2.0 of the STPIS.[8] We propose to apply this revised STPIS and have recalculated our performance data to a basis consistent with this scheme. This allows us to propose targets consistent with the revised STPIS.

16.5.2.1 Revenue at risk

We currently have the default revenue at risk of 5% applied to it under the scheme. We propose that there be no change to this figure.

16.5.2.2 Exclusion Threshold

The AER's proposed approach to calculating the exclusion or major event day (MED) threshold is to apply the methodology indicated in the STPIS Guideline. We currently apply a standard deviation of 2.8β when calculating the MED threshold and we propose that the same value apply for the forthcoming regulatory period.

16.5.2.3 Exclusions

We propose that the exclusions set-out in clauses 3.3, 5.3 and 6.4 of the STPIS scheme apply to us in the 2022-26 regulatory period. We are not currently proposing any modification to these exclusions.

16.5.2.4 Measures

The AER proposes to set applicable parameters for reliability of supply (system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI) and momentary average interruption duration index (MAIFI)).

We propose that the Customer service (telephone answering parameter) should not apply to us in the 2022-26 regulatory period. We have instead proposed that this parameter is replaced by CSIS. Clause 5.1(b) of the STPIS states that the telephone answering parameter will apply unless the AER determines otherwise in its distribution determination for a DNSP. We consider the AER should exercise this discretion not to apply the telephone answering parameter because we are proposing a more robust measure of customer satisfaction.

As noted above, the AER has changed its approach to segmenting the network according to feeder categories (CBD, urban, short rural and long rural for each distributor). The AER has amended the definition of an urban feeder to a feeder "which is not a CBD feeder, has a 3-year average maximum demand over the 3-year average feeder route length greater than 0.3 MVA/km". This differs from the definition of an urban feeder in the EDC, "which is not a CBD feeder, with load density greater than 0.3 MVA/km". The AER's revision clarifies the measurement basis for making a feeder classification decision and allows for regular updating of the feeder classifications. As such, we propose to adopt the feeder definition specified in the STPIS.

The AER proposes to set performance targets based on the distributor's average performance over the past five regulatory years. We support this approach as the foundation for calculating targets. However, the AER has changed the definition of a momentary interruption from less than 1 minute to less than 3 minutes. We have adjusted our reliability performance to reflect this changed definition and calculated targets consistent with this revised definition.

16.5.2.5 Proposed Targets

The Victorian Governments decision to amend the commencement date of the next regulatory period will impact on the application of the STPIS. Particularly, consideration must be given to the

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8 Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0, November 2018.

best way to set targets in the 2022-26 regulatory period. We propose to calculate the targets using data from the five financial years from 1 July 2014 to 30 June 2019. We do not propose any modifications for any reliability improvements completed or planned in accordance with clause 3.2.1(a)(1A).

We note that the REFCL program is expected to have a material negative impact on our reliability performance because it prevents the functioning of our automated feeder restoration. However, funding has been approved in the REFCL Contingent Project Applications for us to restore reliability to existing levels.[9] As such, no further adjustment for the REFCL program is required.

16.5.2.6 Incentive Rates

The AER is currently revising the Value of Customer Reliability (VCR) and we understand that the AER will apply the revised VCR in its draft and final decisions. To provide an internally consistent incentive framework it is important that the VCR underpinning the capex forecast is also that applied to calculate the STPIS incentive rates. For the purposes of this revenue proposal, we have calculated incentive rates below, based on the existing VCR escalated to the start of the 2022-26 regulatory period.[10]

Table 16-4: STPIS Targets and Incentive Rates for 2022-26

Measure	Average Historic Performance	Modification	Proposed Targets[11]	Proposed Incentive Rates[12]
USAIDI				**(%/minute)**
Urban	76.7477	0	76.7477	0.0228%
Rural Short	188.0970	0	188.0970	0.0217%
Rural long	270.8687	0	270.8687	0.0093%
USAIFI				**(%/0.01 Interruptions)**
Urban	0.8284	0	0.8284	1.4074%
Rural Short	1.9773	0	1.9773	1.3263%
Rural long	2.5821	0	2.5821	0.6547%
MAIFI				**(%/0.01 Interruptions)**
Urban	2.6959	0	2.6959	0.1126%
Rural Short	5.7583	0	5.7583	0.1061%

9 Final Decision AusNet Services Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 1 August 2017, Final Decision AusNet Services Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche two 31 August 2018 and Final Decision AusNet Services Contingent Project Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche three 3 October 2019.

10 The AER's final decision on the values of customer reliability was published on 18 December 2019. We will update to incorporate these revised VCR's in our revised proposal.

11 ASD - STPIS - Target Calculation.xlsx.

12 ASD - STPIS - Incentive Rates Calculator - Public.xlsm.

Rural long	10.5565	0	10.5565	0.0524%
Telephone answering*				
Percentage of calls will be answered within 30 seconds	82.96%	0	82.96%	-0.040

** Note: We are proposing that the telephone answering parameter is not applied in the 2022-26 regulatory period. We have proposed instead that it is replaces with the CSIS scheme. However, we have included the relevant target and incentive rate in this table for completeness. If the AER does not approve a final CSIS, then the telephone answering should continue to apply in the STPIS.*

16.5.2.7 Telephone answering parameter

The STPIS allows that where a DNSP makes a proposal to vary the application of this scheme, that proposal must be in writing and:

- include the reasons for and an explanation of the proposed variation;
- demonstrate how the proposed variation is consistent with the objectives in clause 1.5; and
- if appropriate, include the calculations and/or methodology which differ to that provided for under this scheme.

The STPIS states that the 'telephone answering' parameter referred to in clause 5.1(a)(1) will apply during a regulatory period except where the AER determines otherwise in its distribution determination for a DNSP.

We propose that the telephone answering parameter does not apply in the forthcoming regulatory period. Rather, we propose that it is replaced with the CSIS scheme. We consider the CSIS will provide a more holistic incentive on improving customer satisfaction and so replacing the telephone answering parameter with this scheme better meets the objective of the STPIS. By removing the telephone answering parameter the overall revenue at risk remains unchanged, which means that customers are not exposed to a risk of greater overall charges, but should be more satisfied with the services that they receive.

16.6 Guaranteed Service Levels (GSLs)

The GSL scheme sets threshold levels of service for DNSPs to achieve, and requires direct payments to customers who experience service below the pre-determined level. Consistent with the Framework and Approach, we propose that the targets for the forthcoming regulatory period be based on the five year historic averages from 2015 to 2019. In accordance with clause S6.1.3(4) of the NER, our proposed GSL targets are shown in the table below. Payments under the GSL scheme are made on a calendar year basis, so these targets reflect the calendar year nature of the scheme.

We have committed to absorbing the costs of 'controllable GSL's'. However, this does not change the nature of our obligations or targets, it simply means that we have not sought an opex allowance to cover the full expected cost of the scheme. The costs that we have agreed to absorb relate to GSL payments for missed appointments and not meeting connections timeframes.

However, we note that the Victorian Government is currently consulting on changes to the GSL scheme. There are potentially significant changes that will be made to the GSL scheme and as such we will need to consider the outcome of this review once it is finalised. We will need to incorporate any changes to the GSL scheme into its revised regulatory proposal. Additionally, relevant transitional arrangements should be made to ensure that the existing scheme is appropriately closed out.

Table 16-5: Proposed GSL Targets for 2021 to 2026[13]

	2021 (CY)	2022 (CY)	2023 (CY)	2024 (CY)	2025 (CY)	2026 (CY)
Low reliability payments - 8 events	16,607	16,607	16,607	16,607	16,607	16,607
Low reliability payments - 12 events	4,370	4,370	4,370	4,370	4,370	4,370
Low reliability payments - 24 events	635	635	635	635	635	635
Low reliability payments - 20 hours	14,288	14,288	14,288	14,288	14,288	14,288
Low reliability payments - 30 hours	10,511	10,511	10,511	10,511	10,511	10,511
Low reliability payments - 60 hours	3,798	3,798	3,798	3,798	3,798	3,798
Low reliability payments - 24 momentary events	11,926	11,926	11,926	11,926	11,926	11,926
Low reliability payments - 36 momentary events	4,508	4,508	4,508	4,508	4,508	4,508
Low reliability payments - Duration per Event (12hrs) Urban	2,632	2,632	2,632	2,632	2,632	2,632
Low reliability payments - Duration per Event (18hrs) Rural	353	353	353	353	353	353
New connections	462	462	462	462	462	462
Truck appointment	7	7	7	7	7	7

Source: AusNet Services.

16.7 F Factor Scheme

On 22 December 2016, the Victorian Government published the "f-factor scheme order 2016" (the 2016 Order), which revoked the previous 2011 f-factor scheme Order. The Department of Environment, Land, Water and Planning has noted that the Victorian Government intends to publish updated IRUs for the financial year 2020-21, prior to the commencement of the next regulatory period.

13 ASD - GSL Data - Public.xlsx.

DELWP has advised that new IRU Targets will be published for each Victorian distribution business on the following basis:

- IRU Targets will only be published for a single year – 2020-21 initially;
- IRU Targets will be published no later than June 2020;
- IRU Targets will be calculated on the basis of the most recent five year fire start history that is available; and
- IRU Targets will be adjusted to reflect the estimated benefit of bushfire mitigation activities operating throughout the bushfire season, with a particular emphasis on the operation of Rapid Earth Fault Current Limiters (REFCL).

We have proposed a F-factor IRU target based on the F-factor scheme order 2016 and the targets as they are currently specified in that scheme. However, we note that this target and incentive rate will be updated throughout the regulatory period in accordance with any revised order in council.

Further, with the transition to financial year regulatory period, we propose to recover the 2018-19 F-factor amount in the 6 month period from 1 January 2021 to 30 June 2021. The 2019-2020 F-factor amount will be recovered in the financial year from 1 July 2021 to 30 June 2022 and each subsequent F-factor amount will be recovered in the subsequent financial year.

Table 16-6: Proposed Target and Incentive Rate for 2022-25

Measure	Annual Target	Incentive Rate
Fire start target	221.1	$15,000

Source: AusNet Services.

16.8 Demand Management Incentive Scheme and Allowance

The AER's F&A paper set-out that they propose to apply the DMIS and DMIAM apply as set out in:

- Demand Management Incentive Scheme, Electricity distribution network service providers, December 2017.
- Demand Management Innovation Allowance Mechanism, Electricity distribution network service providers, December 2017.

We endorse the AER position. We have included the DMIA allowance, calculated in accordance with the revised scheme, in our revenue allowance.

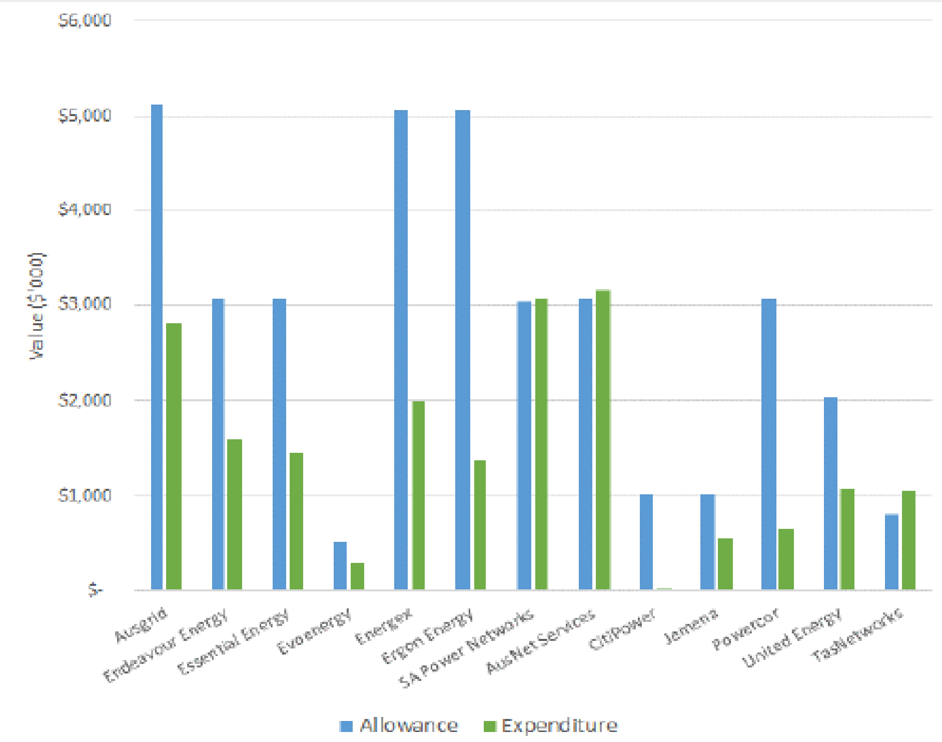
Table 16-7: DMIA allowance ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
DMIA Allowance	0.71	0.71	0.69	0.68	0.68	3.46

Source: AusNet Services.

We have a track record as one of the few electricity distributors to fully utilise the allowance. We also deliver quality projects that have been recognised by industry awards.

Figure 16-6: DMIA allowance versus expenditure



Source: AER 2019, Decision: Approval of Demand Management Innovation Allowance (DMIA) expenditures by distributors in 2017–18 and 2018, September.

The demand management innovation projects delivered in the current regulatory period are shown in the table below.

Table 16-8: Demand management innovation projects delivered 2016-20

Project name	Project description
Grid Energy Storage System	A grid scale hybrid battery and generator system was developed to test the network and customer value of large scale energy storage. Whilst delivered in the 2011-2015 regulatory period, testing and further innovation continued into the 2016-2020 period. Key value streams assessed included peak demand management, power quality improvement and increased customer supply reliability through backup power provision as an islanded microgrid. This project has led to the development of the Mallacoota Battery Storage project to provide increased customer supply reliability to a remote community.
Mooroolbark Mini Grid	This project tested the value that can be harnessed from a future of high customer DER and was the first residential microgrid in Australia to be developed in a residential area. The project has been instrumental in informing the broader industry knowledge base around transition to a high DER future and led to targeted projects such as Networks Renewed that focussed on enabling a higher penetration of solar power to be hosted by the network.
Peak Partners – Residential Demand Response	Peak Partners was our first pilot project for residential demand response. We compared the effectiveness of different DR techniques (voluntary response with web portal interface,

Project name	Project description
	voluntary response with real-time data, automated air conditioning load control and smart meter supply capacity control) and tested customer acceptance. This pilot was successful in proving very high customer acceptance, strong demand reduction performance and a preferred technique of voluntary response with web portal interface. It subsequently led to the development of our expanded GoodGrid program.

The demand management innovation projects proposed for the 2022-26 regulatory period are shown in the table below.

Table 16-9: Proposed demand management innovation projects 2022-26

Project name	Project description
Residential Demand Response – behavioural techniques	Building on the lessons learned from our successful GoodGrid program, this project will test the value of customer interaction tools such as apps and gamification, and will seek to prove the economics and efficiency of behavioural demand response at the larger scale required to deliver network augmentation deferrals and therefore reduced costs to customers. Testing methods to lower the cost of customer acquisition will be important.
Residential Demand Response – automated load control	Load control offers the prospect of increased demand response levels and a simplified customer experience, but suffers from the costs to implement. This project builds on our GoodGrid program and will experiment with new technologies (such as smart appliances) and business models (such as retail partnerships) that can reduce program costs. The project will take an initial focus on air-conditioning load control via industry standard and proprietary communications protocols, but may also include battery storage and home energy management systems
Integrating demand management into Control Room operations	This project will identify and test control room integration solutions and automation platforms that can apply to both commercial customer and residential customer demand response as well as network support from generation and energy storage devices.
Large scale storage integration	Building on the trial of our own Grid Scale Storage System, this will test and deploy management solutions for third-party storage systems in order to harness network support value and reduce costs to customers. This will harness existing capability within our proof-of-concept Distributed Energy Network Optimisation Program and will develop specific functionality for large scale storage systems in order to test the end-to-end commercial solution.
Electric vehicle charging management	Electric vehicle adoption is increasing steadily and management of charging demand patterns will be critical in reducing the costs to all customers of the EV transition. This project will collaborate with technology providers and other utilities to test a range of

Project name	Project description
	charging management approaches in preparation for EVs becoming mainstream.
Thermal storage solutions	Thermal storage offers an alternative to electrical storage for managing peak network demand that is driven by heating or cooling needs. Particularly at larger scales (such as for commercial cold storage facilities) thermal storage has the potential to be more cost effective than electrical storage. A feasibility study will be the first stage of an innovation pathway for thermal storage.

16.9 Efficiency Benefit Sharing Scheme

This section sets out our proposal with respect to the application of the efficiency benefit sharing scheme (EBSS). It sets out:

- the calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period; and
- our proposal for the operation of the EBSS in the next period.

As a result of the change in the regulatory period, the AER has provided draft amendments to the operation of the EBSS to ensure that the impact of the period of 1 January 2021 to 30 June 2021 is appropriately factored into the EBSS calculation. We have adopted the revised RIN template issued by the AER for the purposes of this calculation. This is a departure from the EBSS as setout in the 2016-2020 final decision. This departure is appropriate as it ensures the incentives of the EBSS are correctly applied across the transition period.

16.9.1 The current period carry over amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming regulatory period in accordance with the AER's final decision and determination on the application of the EBSS for the 2016-2020 regulatory period. This calculation involved the following steps:

- Determining opex for the EBSS in 2014-2019, which is equal to total opex less:
  - GSL payments;
  - Changes in capitalisation policy in 2018;
  - Merits Review Opex;
  - Movements in provisions;
  - DMIA opex;
- Calculating the efficiency carryover amount by comparing 2016-20 controllable opex with the adjusted regulatory allowances.

16.9.1.1 Compliance with Section 71YA of the NEL

We are required to be compliant with Section 71YA of the NEL. This requires that where any expenditure or cost has been incurred or is forecast to be incurred by us as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL, we must identify the expenditure or cost and provide a statement attesting that we have not:

- included any of that expenditure or cost, or any part of that expenditure or cost, in the capital or operating expenditures contained in its regulatory proposal; and
- recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and

- sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users.

We audited opex in 2015, 2016 and 2017 includes costs incurred as a result of or incidental to merits review or other non-judicial review. To ensure compliance with Section 71YA of the NEL we have removed this expenditure from our opex for the purposes of calculating the EBSS.[14]

16.9.1.2 Changes in capitalisation policy

A revised accounting standard (AASB 16) applied from 1 April 2019. Under the revised accounting standard, operating leases became 'Right to Use' (capital) assets. As a result, leases must now be treated as capex rather than opex. We have removed the lease costs from our 2018 base year for the purpose of calculating our opex allowance. Correspondingly, we have removed these lease cost from the opex used for the EBSS calculation in 2018 to be consistent with the base year used for forecasting opex in the base, step and trend forecasting approach. Without this we would receive a lower opex allowance and no offsetting increase in its EBSS carryover. If the AER does not accept this change to our opex for EBSS purposes, then we consider the lease amounts would need to be added back into our opex allowance for the purposes of the base, step and trend forecasting methodology.

The following table sets out the above steps, which result in a proposed efficiency carryover amount of $90.3 million ($2021).

Table 16-10: Calculation of EBSS carryover amount ($m 2021)

	2016	2017	2018	2019	2020	
Total opex (excluding Debt Raising Costs)	**264.2**	**234.1**	**218.1**	**205.8**		
Less: DMIA costs	-0.1	-0.3	-0.2	-0.2		
Less: GSL payments	-19.4	-3.8	-7.0	-6.6		
Less: Movements in provisions	-0.5	0.6	-0.5	-		
Less Capitalisation Policy Changes	-	-	-4.6	-		
Opex For EBSS	244.1	230.7	205.7	199.0		
Approved allowance	**238.0**	**242.5**	**248.5**	**253.5**		
Incremental efficiency gain/loss	-4.2	17.9	31.0	11.7	-11.7	
	2021-22	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**Total**
Carryover of efficiency gain/loss made in:						
2016	-2.1	0.0	0.0	0.0	0.0	
2017	17.9	9.0	0.0	0.0	0.0	
2018	31.0	31.0	15.5	0.0	0.0	
2019	11.7	11.7	11.7	5.8	0.0	
2020	-11.7	-11.7	-11.7	-11.7	-5.8	
HY2021	0.0	0.0	0.0	0.0	0.0	
Efficiency carryover amount	**46.8**	**40.0**	**15.5**	**-5.8**	**-5.8**	**90.7**

14 ASD - Merits Review Opex - Public.xls.

Source: AusNet Services

16.9.2 The 2022-26 regulatory period

In the Framework and Approach, the AER stated that they intend to apply the EBSS to the Victorian distributors in the 2022–26 regulatory period if they are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers. The AER stated that this will occur only if the opex forecast for the following period is based on the distributors' revealed costs. We have proposed to use the base step and trend forecasting approach for its opex and as such, our forecast is based on our revealed costs. We propose to apply the latest version of the EBSS in the 2022-26 regulatory period.

16.9.2.1 Proposed exclusions

We propose to remove these categories of opex not forecast using a single year revealed cost approach in the following period. This is consistent with the approach applied in the 2016-2020 regulatory period and remains appropriate in the forthcoming regulatory period. Where a revealed cost approach to forecasting the opex allowance is not used, then the EBSS should not be applied to those forecasts.

- GSL payments are one such category, where the amount forecast is based on a five year average. We consider that GSL payments should be excluded from both the allowance and the actuals when assessing the efficiency benefit under the EBSS Guideline. If GSL payments are not excluded this results in an incentive payment on an incentive payment which changes, unintentionally, the underlying jurisdictional GSL incentive which were developed after an assessment of customers' willingness to pay and the balance between the service incentives and efficiency incentives generally.
- We accept the AER approach to setting debt raising costs using its current benchmark methodology, which embeds a benchmark significantly below actual costs. Debt raising costs must also be excluded from the EBSS calculation. To do otherwise results in a continuous never ending penalty for the distributor which would clearly be inconsistent with both the requirements of clause 6.5.8 of the NER and the NEO.
- As discussed in Chapter 11, we have proposed that the innovation allowance would be on a 'use it or lose it' basis and as such, it is appropriate to exclude it from the EBSS to ensure that we do not receive an EBSS reward if we underspend this allowance.
- The DMIA is also specifically designed to be a "use it or lose it" research allowance and should continue to be excluded from EBSS calculations.

Therefore, excluding these costs better achieves the requirements of clause 6.5.8 of the NER and the NEO.

16.9.2.2 Proposed forecast opex for the EBSS

Table 16-11 below sets out the proposed opex for the EBSS in the 2022-26 regulatory period.

Table 16-11: Proposed opex for the EBSS ($m 2021)

	2022 (FY)	2023 (FY)	2024 (FY)	2025 (FY)	2026 (FY)
Forecast opex (excluding DMIA)	**239.75**	**243.30**	**246.93**	**250.37**	**253.04**
Less excluded costs					
Debt raising costs	2.31	2.35	2.37	2.38	2.39
GSL	9.34	9.34	9.34	9.34	9.34
Innovation Program	0.24	0.24	0.24	0.24	0.24
Opex for EBSS ($m, 2021)	**227.9**	**231.4**	**235.0**	**238.4**	**241.1**

Source: AusNet Services.

16.10 Capital Efficiency Sharing Scheme

This section sets out our proposal with respect to the application of the Capital Expenditure Sharing Scheme (CESS). It sets out:

- The calculation of the current period's efficiency carryover amount, which will be recovered during the forthcoming period; and
- our proposal for the operation of the CESS in the next period.

16.10.1 The current period carryover amount

We have calculated the efficiency carryover amount to be recovered during the forthcoming regulatory period in accordance with the AER's final decision and determination on the application of the CESS for the 2016-2020 period. This calculation involved the following steps:

1. Calculate the capex applicable to the CESS, by removing Customer Contributions and Asset disposal from total capex.
2. Calculate the cumulative underspend amount for the current regulatory period in net present value terms.
3. Apply the sharing ratio of 30% to the cumulative underspend amount to work out what our share of the underspend should be.
4. We calculate the CESS payments taking into account the financing benefit of the underspend.

Table 16-12: Calculation of CESS carryover amount ($m 2021)

	2016	2017	2018	2019	2020
Capex allowance	333.05	418.65	395.42	431.84	416.68
Actual capex	298.76	332.57	367.37	404.04	411.89
Underspend	34.29	86.09	28.05	27.80	4.79
Year 1 benefit		1.31	1.32	1.32	1.31
Year 2 benefit			3.27	3.29	3.25
Year 3 benefit				1.05	1.04
Year 4 benefit					1.01
Year 5 benefit					
NPV underspend	42.43	101.55	31.27	29.27	4.79
NPV financing benefit	0.00	1.55	5.12	5.96	6.60
Total underspend (NPV) adjusted for deferrals	209.31				
Relevant sharing ratio	30%				
Consumer share	146.52				
NSP share	62.79				
Total NSP financing benefit (NPV)	19.22				
NPV of CESS payments (post-adjustment) 30 December 2020	43.57				
NPV of CESS payments (post-adjustment) 30 June 2021	44.55				
CESS Payment Per Year ($2021 million)	$9.50	$9.50	$9.50	$9.50	$9.50

Source: AusNet Services.

16.10.2 The 2022-26 regulatory period

In the Framework and Approach, the AER stated that they intend to apply the CESS to the Victorian DNSPs in the 2021–25 regulatory period (now the 2022-26 regulatory period). We endorse that position.

As discussed in Chapter 11, we have proposed that the innovation allowance would be on a 'use it or lose it' basis and as such, it is appropriate to exclude it from the CESS to ensure that we do not receive a CESS reward if we underspend this allowance.

16.10.2.1 Proposed forecast capex for the CESS

Table 16-13 below sets out the proposed capex for the CESS in the 2022-26 regulatory period.

Table 16-13: Proposed capex for the CESS ($m 2021)

	2022 (FY)	2023 (FY)	2024 (FY)	2025 (FY)	2026 (FY)
Forecast Net Capex	312.3	296.2	296.0	280.9	282.5
Less excluded costs					
Innovation Program	1.3	1.3	1.3	1.3	1.3
Capex for CESS ($m, 2021)	**311.0**	**294.9**	**294.7**	**279.7**	**281.2**

Source: AusNet Services.

16.11 Supporting documentation

In addition to the PTRM and relevant parts of the RIN templates submitted with this proposal, the following documents are provided in support of this chapter:

- Spreadsheet entitled “ASD - STPIS - Target Calculation.xlsx” showing the calculation of the reliability targets;
- Spreadsheet entitled “ASD - Incentive Rates Calculator - Public” showing the incentive rates;
- Spreadsheet entitled “CESS.xls” showing the CESS calculation;
- Spreadsheet entitled “EBSS.xls” showing the EBSS calculation;
- Spreadsheet entitled “CSAT data, targets and reporting template - Public” showing the calculation of CSIS targets.

A number of other supporting documents also form part of this proposal.

17 Cost pass through

17.1 Key points

- We have undertaken an assessment to ensure we have appropriate mechanisms in place to mitigate the risk that unforeseen costs will arise during the 2022-26 regulatory period, including a review of the appropriateness of our insurance cover and our ability to increase that cover if need be. One of the risk mitigation mechanisms that a prudent and efficient service provider would employ is to propose nominated pass through events to manage unpredictable, infrequent and high cost events that are beyond our control. Therefore, we propose that the following additional nominated pass through events should apply in the forthcoming regulatory period:
    - insurance coverage event;
    - insurance premium event;
    - insurer credit risk event;
    - terrorism event;
    - natural disaster event;
    - retailer insolvency event; and
    - electric vehicle uptake event.
- Cost pass through protections are included in the Rules to lower overall costs for customers. If services providers were unable to access these protections, it would be efficient to take alternative measures to mitigate unforeseen costs associated with these risks, such as taking out a higher level of insurance protection. This would have higher ongoing costs for customers.
- Our proposed nominated pass through events are consistent with the nominated pass through event considerations prescribed in the Rules. In particular, the events we propose as nominated events represent the most cost effective and efficient balance between our need to mitigate the risks we face in and our commitment to helping customers manage issues associated with electricity affordability.
- We will rely on other risk mitigation options where available to manage risk during the regulatory period, rather than simply relying on the pass through mechanisms. We adopt prudent risk and asset management measures to help ensure the safety, reliability and security of supply to our customers.

17.2 Chapter structure

The structure of the remainder of this chapter is:

- Section 17.3 explains our approach to developing cost pass through events
- Section 17.4 summarises our nominated pass through events and the relevant definitions.
- Section 17.5 explains other events that fall under the prescribed pass through events.
- Section 17.6 describes how the pass through events will be applied to alternative control services.

17.3 Approach to developing cost pass through events

A cost pass through mechanism is an efficient method of managing unpredictable, high cost events that are beyond our control. This cost recovery mechanism ensures that our regulated revenue does not include any amount to insure against these events, either through self-insurance or through commercial insurance, thereby lowering the costs to our customers of operating our network. Instead, we recover only the efficient costs to us caused by one of these events, subject to the AER's approval, and only if the event occurs.

By allowing DNSPs to pass through material costs associated with events outside of their control, the cost pass through provisions in the NER provide a key mechanism to address the cost impact of uncertain events. The cost pass through mechanism ensures:

- DNSPs have a reasonable opportunity to recover at least their efficient costs;
- DNSPs face an incentive to manage risk effectively; and
- expenditure forecasts and approved allowances best reflect the prudent and efficient costs incurred by DNSPs.

In addition to cost pass through arrangements, DNSPs may address risk through several other mechanisms. These include:

- including costs directly in opex and capex allowances;
- utilising third party insurance cover and/or self-insurance; and
- proposing contingent projects in accordance with rule 6.6A.

Without these mechanisms, there is a risk that the uncertainty associated with an event will create unfunded material expenditure that results in a DNSP's actual expenditure exceeding its approved regulatory allowances for a given regulatory period. In these circumstances, the DNSP may be forced to either defer or redirect expenditure from other projects where doing so is not in the long-term interests of its customers. Where these options are not available, such an event may threaten the financial sustainability of the DNSP to the extent that it is unable to raise the capital required to maintain and operate its network in order to deliver network services.

Cost pass-through provisions are most appropriate for risks that cannot be dealt with through the above mechanisms. These risks are typically associated with high consequence, low probability events, or where there is substantial uncertainty with respect to the cost impact of an event known to be occurring over a future regulatory period. The cost impact of these events cannot be predicted with sufficient certainty for it to be included in expenditure allowances, while insurance and self-insurance is not likely to be available on a cost-effective basis.

Contingent projects are typically relied upon when a DNSP can clearly identify the scope and cost impact of an event, but uncertainty exists with respect to the trigger that would require it to incur costs (e.g. demand exceeding a certain threshold). Accordingly, contingent projects are not considered a useful risk management tool for events with unpredictable cost impacts.

The pass through events prescribed in the NER cover a range of scenarios:

> *"(1) a regulatory change event;*
>
> *(2) a service standard event;*
>
> *(3) a tax change event;*
>
> *(4) a retailer insolvency event; and*
>
> *(5) any other event specified in a distribution determination as a pass through event for the determination."*[1]

In considering whether to nominate any additional events as a pass through event, we have been guided by the NEO. Generally, a nominated pass through event is unpredictable as to its occurrence, cost and/or timing. For this reason, the long-term benefit to consumers of including the costs associated with a specific event in our total capex or opex forecasts (as appropriate) compared to excluding those costs and using the cost pass through mechanisms has been

[1] NER, Clause 6.6.1(1a1).

considered. In general, where the accuracy and efficiency of our forecasts is improved by recovering those costs (if and to the extent they arise) through a pass through mechanism rather than via our approved expenditure allowance, we believe this promotes the achievement of the NEO.

Our approach to identifying cost pass through events has involved:

- identifying potential changes to our operating environment and regulatory and legislative framework that may create risk over the forthcoming regulatory period;
- assessing the certainty, likelihood and consequence of each risk to determine whether risks can be accounted for in expenditure forecasts or in the case of low consequence risks, absorbed internally;
- reviewing the available risk management measures that may be used to mitigate or prevent risks, including:
  - opex;
  - capex;
  - insurance;
  - self-insurance;
  - WACC; and
  - prescribed pass through events in the NER.

We have identified seven events that do not presently satisfy any of the four prescribed pass through events: an insurance coverage event, an insurance premium event, an insurer credit risk event, a natural disaster event, a terrorism event, a retailer insolvency event (in Victoria) and an electric vehicle uptake event. We have also identified that there may be a need to apply to pass through costs arising from amendments to the Electricity Distribution Code arising from the Essential Services Commission (ESC)'s review, depending on its conclusions. However, we consider this event is likely to be covered by the regulatory change event prescribed in the NER. Our seven proposed nominated pass through events are discussed further in section 17.4.

We consider that adopting our proposed nominated pass through events is also consistent with the Revenue and Pricing Principles. In particular, section 7A(2) of the NEL requires the AER to provide us with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control network services. Without the proposed nominated pass through events, we are not provided such an opportunity because the costs associated with these events have not been accounted for elsewhere in our expenditure proposal.

The matters the AER must consider when assessing proposed nominated events, known as the nominated pass through event considerations, are defined in the NER as follows:

> *"(a) whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to (4) (in the case of a distribution determination) or clause 6A.7.3(a1)(1) to(4) (in the case of a transmission determination);*
>
> *(b) whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;*
>
> *(c) whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;*
>
> *(d) whether the relevant service provider could insure against the event, having regard to:*
>
> *(1) the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or*
>
> *(2) whether the event can be self-insured on the basis that:*
>
> *(i) it is possible to calculate the self-insurance premium; and*

(ii) the potential cost to the relevant service provider would not have a significant impact on the service provider's ability to provide network services; and.

(e) any other matter the AER considers relevant and which the AER has notified Network Service Providers is a nominated pass through event consideration."[2]

Our approach to identifying cost pass through events ensures that risk is managed through the most appropriate mechanism. As such, our network tariffs will reflect the lowest sustainable costs of providing network services, consistent with the long-term interests of customers

17.4 Proposed cost pass through events

In addition to the prescribed pass through events defined in the NER, we propose seven nominated pass through events for the forthcoming regulatory period. These cost pass through events, which have been developed in accordance with the approach set out in section 17.3, are:

- An insurance coverage event;
- An insurance premium event;
- An insurer credit risk event;
- A terrorism event;
- A natural disaster event;
- A retailer insolvency event; and
- An electric vehicle uptake event.

Each of these events is discussed below.

17.4.1.1 Insurance coverage event

17.4.1.2 Background

We maintain a level of insurance cover that is commensurate with the scale and size of our operations, the risks assessed to be associated with our operations, and industry standards and practices. The premiums associated with bushfire insurance cover are incorporated in our proposed opex forecast through our base year opex. Our base year opex also includes actual self-insurance costs incurred that relate to liability losses falling below the deductible for our insurance cover.

We are exposed to the risk that we incur liability losses that exceed our insurance coverage. We therefore consider that nominating an 'insurance coverage event' as a cost pass through event is a prudent and efficient way to mitigate this risk. We consider that our insurance coverage event satisfies the nominated pass through event considerations and that there is a sound basis for the AER to accept it as a nominated pass through event. This is because:

- the insurance coverage event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of an insurance coverage event can be clearly identified at the time of the AER's final determination;
- our ability to prevent or limit an insurance coverage event on a cost-effective and efficient basis is limited. That being said:
  - the protection of communities within our area of operations is of critical importance to us, and we have developed a sophisticated approach to managing network safety; and

2 NER, Chapter 10.

   - the substantial deductible payable on our bushfire liability policy creates a strong financial incentive for us to prevent or mitigate the risk of such events from occurring in the first place; and
- as explained previously, it is not possible to calculate self-insurance premiums for liability losses that exceed the policy coverage with certainty.

We also consider that accepting the insurance coverage event is consistent with the Revenue and Pricing Principles. In particular, section 7A(2) of the NEL requires us to be provided with a reasonable opportunity to recover at least the efficient costs we incur in providing direct control network services. Absent the insurance coverage event, we will be precluded from receiving such an opportunity because the costs of an insurance coverage event have not been allowed for elsewhere in this proposal.

17.4.1.3 Proposed definition

Our proposed definition of an Insurance Coverage Event for the forthcoming period is:

1. *An Insurance Coverage Event occurs if:*

(a) *AusNet Services makes a claim or claims and* receives the benefit of a payment or payments under a relevant insurance policy or program of insurance policies;

(b) *AusNet Services incurs costs beyond the policy* limit, or which otherwise fall outside the scope of the cover provided, under the relevant insurance policy or program of insurance policies; and

(c) *the* costs beyond the policy limit, or otherwise outside the scope of the cover provided, under the relevant insurance policy or program of insurance policies increase the costs to AusNet Services in providing direct control services.

2. *For this Insurance Coverage Event:*

(a) *a relevant insurance policy is an insurance policy held during the 2022-2026 regula*tory control period or a previous regulatory control period in which AusNet Services was regulated;

(b) *the scope of cover under a program of policies c*onsiders the bands of liability for which AusNet Services is insured, and within those bands, the minimum and maximum cover amounts of each insurance policy; and

(c) *AusNet Services will be deemed to have made a* claim on a relevant insurance policy if the claim is made by a related party of AusNet Services in relation to any aspect of the network or AusNet Services' business.

3. *In making a determination on an Insurance Coverage Event, the AER will have regard to, amongst other things:*

(a) *the* insurance policy or program of policies applicable to the event;

(b) *expert advice about the level of insuranc*e cover appropriate for AusNet Services (the benchmark level of insurance);

(c) *the level and scope of insurance that a prudent and efficient* NSP would obtain in respect of the event, considering factors including (but not limited to):

   i. *the number and credit rating of insurers offering insurance cover to NSPs;*
   ii. *the cost of purchasing the insurance cover relative to the value of the cover;*
   iii. *the cost of purchasing equivalent insurance cover in previous regulatory control periods;*

(d) *evidence of AusNet Services' efforts to obtain the benchmark level of insurance cover;*

(e) *if AusNet Services did not obtain the* benchmark level of insurance cover, evidence that:

   iv. *AusNet Services' Board approved the lower level of insurance cover as prudent and efficient; or*

> *v. AusNet Services engaged with customers or customer representatives concerning the reasons for the lower level of insurance cover; and*

(f) any assessment by the AER of AusNet Services' insurance cover in making its distribution determination for the relevant regulatory control period

17.4.1.4 Background

Given recent unfavourable developments in the international liability insurance market, we are proposing an 'insurance premium event' pass-through. An 'insurance premium event' occurs if we incur costs above the allowance for insurance premiums included in the forecast operating expenditure allowance approved in the AER's final decision for the next regulatory period for the relevant insurance policy.

The long-term interests of our customers are better served by providing pass-through protections rather than the additional opex to cover the step changes in premium costs. For these reasons, we propose an 'insurance premium event' as a nominated cost pass through event.

We consider that our insurance premium event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the insurance premium event is not covered by any of the prescribed cost pass through events set out in the NER and does not duplicate the insurance coverage event;
- the nature and type of the event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent an insurance premium event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, we consider several risk management factors when assessing whether to insure with a particular provider, such as the insurer's track record, size, credit rating and reputation; and
- the relative infrequency and potentially substantial financial impact of insurance premium events creates significant practical challenges. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the unlikely circumstances that an insurance premium event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

Note: The relevant insurance policy is an insurance policy held during the next regulatory period.

17.4.1.5 Proposed definition

Our proposed definition of an Insurance Premium Event for the forthcoming period is:

1. *An Insurance Premium Event occurs if AusNet Services* incurs costs in respect of insurance premiums, which exceed the allowance for insurance premiums included in the forecast operating expenditure allowance approved in the AER's distribution determination for the 2022-26 regulatory control period.

Note: Insurance premiums relate to the costs payable to obtain liability insurance cover during the regulatory control period commencing 1 July 2021 to 30 June 2026.

2. *In making a determination on an Insurance Premium Event, the AER will have regard to, amongst other things:*

(a) the level of liability insurance cover that a prudent and efficient distribution network service provider operating a network similar to AusNet Services' would obtain in respect of liability exposure;

(b) whether the insurance premiums allocated to AusNet Services is in accordance with its cost allocation methodology approved under rule 6.15 of the NER; and

(c) *any assessment by the AER of AusNet Services' liability insurance cover in making its distribution determination for the 2022-26 regulatory control period.*

17.4.2 Insurer credit risk event

17.4.2.1 Background

The cost impacts to us of one of our insurers becoming insolvent are potentially significant. We could be subject to higher or lower premiums, or a higher or lower claims limit or deductible.

While the retailer insolvency event (if specified by the AER in its determination) provides a cost recovery mechanism in the event of a retailer becoming insolvent, we consider the need for both the retailer insolvency and insurer credit risk events because we may incur costs that the insolvency event would not ordinarily cover.

For these reasons, we propose an 'insurer credit risk event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with an insurer credit risk event will be net of any insurance payout made to us or recovered through a retailer insolvency event pass through application.

We consider that our insurer credit risk event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the insurer credit risk event is not covered by any of the prescribed cost pass through events set out in the NER and does not duplicate the retailer insolvency event;
- the nature and type of the event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent an insurer credit risk event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, we consider several risk management factors when assessing whether to insure with a particular provider, such as the insurer's track record, size, credit rating and reputation; and
- the relative infrequency and potentially substantial financial impact of insolvent insurer events creates significant practical challenges for self-insuring for such events. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the unlikely circumstances that an insurer credit risk event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

17.4.2.2 Proposed definition

Consistent with the AER's views and recent determinations[3], and the Insurer Credit Risk event definition specified for us in the current regulatory period, our proposed definition of an insurer credit risk event for the forthcoming period is:

1. *An Insurer Credit Risk Event occurs if a nominated insurer of AusNet Services* becomes insolvent and, as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, AusNet Services:

(a) *is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*

(b) *incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*

[3] AER, Ausgrid Final Decision 2019-24 – Overview, p. 45.

2. *In assessing an Insurer's Credit Risk Event pass through application, the AER will have regard to, amongst other things:*

(a) *AusNet Services' attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation.*

(b) *in the event that a claim would have been made after the insurance provider became insolvent, whether AusNet Services had reasonable opportunity to insure the risk with a different provider.*

17.4.3 Natural disaster event

17.4.3.1 Background

The cost impact of a natural disaster on our network assets can be potentially significant. Potential natural disasters that could cause significant property damage include, but are not limited to, bushfires, earthquakes, storms and floods. Our insurance coverage provides some protection against property damage caused by natural disasters; however, the cost impact of a natural disaster could materially exceed the coverage provided by these policies.

Further, while the insurance coverage event provides a cost recovery mechanism in the event of a natural disaster, there is a need for both pass through events because the NSP may incur costs that an insurance policy would not ordinarily cover.

For these reasons, we propose a 'natural disaster event' as a nominated cost pass through event. Importantly, any pass through amount claimed in association with a natural disaster event will be net of both insurance and self-insurance cover, and any amounts recovered through an insurance coverage event claim.

We consider that our natural disaster cap event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and materially increases our costs. This position is consistent with the nominated pass through event considerations:

- the natural disaster event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of the event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent a natural disaster event from occurring and/or can substantially mitigate the cost impacts of such an event is limited;
- our insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage and other losses associated with a natural disaster. However, the cost impact of a natural disaster could materially exceed the limits of our insurance cover. Any pass through amount claimed in association with a natural disaster event will be net of payouts made under these policies; and
- the relative infrequency and potentially crippling financial costs of a natural disaster (particularly bush fires) creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the event that a natural disaster event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

17.4.3.2 Proposed definition

Consistent with the AER's views and recent determinations[4], and the natural disaster event definition specified for us in the current regulatory period, our proposed definition of a natural disaster event for the forthcoming period is:

> 1. *A Natural Disaster Event means any natural disaster including but not limited to cyclone, fire, flood, earthquake or other natural disaster that occurs during the regulatory control period and increases the costs to AusNet Services in providing direct control services, provided the cyclone, fire, flood or other event was not a consequence of the acts or omissions of AusNet Services.*
> 2. *In assessing a Natural Disaster Event pass through application, the AER will have regard to, amongst other things:*
>
> *(a) whether AusNet Services has insurance against the event, and*
>
> *(b) the level of insurance that an efficient and prudent NSP would obtain in respect of the event.*

17.4.4 Terrorism event

17.4.4.1 Background

The cost impacts of an act of terrorism, such as a cyber-attack on our IT or network operations systems could potentially be significant. Our insurance policies provide some cover against losses caused by terrorism; however, the cost impact of such an event could materially exceed the limits of these policies.

Further, while the insurance coverage event provides a cost recovery mechanism in the event of an act of terrorism, there is a need for both the insurance coverage and terrorism events because the NSP may incur costs that an insurance policy would not ordinarily cover.

For these reasons, we propose a 'terrorism event' as a nominated cost pass through event. Importantly, any pass through amount claimed in a pass through application for a terrorism event will be net of any insurance payout made to us and any amounts recovered through an insurance coverage event pass through application.

We consider that our terrorism event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the terrorism event is not covered by any of the prescribed cost pass through events set out in the NER;
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the extent to which we can reasonably prevent a terrorism event from occurring and/or can substantially mitigate the cost impacts of such an event is limited. That said, we have a range of security and other measures in place which are intended to prevent acts of terrorism, and to mitigate the cost impact of such an event should one occur;
- our insurance coverage, which has been obtained on a cost-effective basis, provides some protection against property damage caused by a terrorism event. However, the cost impact of such an event could materially exceed the coverage provided by this insurance. Any pass through amount claimed in association with a terrorism event will be net of any insurance payout we

[4] AER, Ausgrid Draft Decision 2019-24 – Pass through events, p. 13.

receive, and any amount recovered through an insurance coverage event pass through application; and

- the relative infrequency and potentially very high costs of a terrorism event creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a terrorism event occurs and causes a material increase in our costs. We consider that managing costs in this way is prudent and in the long-term interest of consumers.

17.4.4.2 Proposed definition

Consistent with the AER's views and recent determinations[5], and the terrorism event definition specified for us in the current regulatory period, our proposed definition of a terrorism event is:

1. A Terrorism Event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

(a) from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or to create fear amongst the public, or any section of the public); and

(b) increases the costs to AusNet Services in providing direct control services.

2. In assessing a Terrorism Event pass through application, the AER will have regard to, amongst other things:

(a) whether AusNet Services has insurance against the event;

(b) the level of insurance that an efficient and prudent DNSP would obtain in respect of the event; and

(c) whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

17.4.5 Retailer insolvency event

17.4.5.1 Background

Retailer insolvency is a category of prescribed pass through event under the NER, which defines it as:

The failure of a retailer during a regulatory control period to pay a DNSP an amount to which the service provider is entitled for the provision of direct control services, if:

a. an insolvency official has been appointed in respect of that retailer; and

b. the DNSP is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.

The prescribed pass through event in the NER is effective in all jurisdictions other than Victoria. We therefore rely on consistency with other participating jurisdictions that have started the National Energy Retail Law (NERL) as a relevant matter to be considered by the AER. To ensure we have access to the same protection in the event of a retailer failure as other DNSPS in jurisdictions where the NERL applies, we propose a pass through event for retailer insolvency to manage the risk of retailers defaulting on payment of their network charges.

For these reasons, we propose a 'retailer insolvency event' as a nominated cost pass through event. Importantly, any pass through amount claimed in a pass through application for a retailer

5 AER, Ausgrid Final Decision 2019-24 – Overview, p. 45.

insolvency event will be net of any insurance payout made to us and any amounts recovered through an insurance coverage event pass through application.

We consider that the retailer insolvency event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event occurs and results in a material increase in our costs. This position is consistent with the nominated pass through event considerations:

- the retailer insolvency event outlined in the NER does not apply to Victorian DNSPs as the NERL has not been adopted in Victoria;
- the nature and type of event can be clearly identified at the time that the AER makes its determination for us;
- the cost impact of such an event could materially exceed the coverage provided by our insurance coverage; and
- the extent to which we can reasonably prevent a retailer insolvency event from occurring and/or can substantially mitigate the cost impacts of such an event is limited; and
- the relative infrequency and potentially very high costs of a retailer insolvency event creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more efficient arrangement for managing the cost impacts in the unlikely circumstances that a retailer insolvency event occurs and causes a material increase in our costs. We consider that managing costs in this way is prudent and in the long-term interest of consumers.

17.4.5.2 Proposed definition

Consistent with the AER's views, and the retailer insolvency event definition specified for us in the current regulatory period, our proposed definition of a retailer insolvency event is:[6]

> 1. *Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, Retailer Insolvency Event has the meaning set out in the NER as in force from time to time, except that:*
>
> (a) *where used in the definition of 'Retailer Insolvency Event' in the NER, the term 'retailer' means the holder of a licence to sell electricity under the Electricity Industry Act 2000 (Vic); and*
>
> (b) *other terms used in the definition of Retailer Insolvency Event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the NER or National Energy Retail Law not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).*
>
> 2. *For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the NER are modified in respect of this Retailer Insolvency Event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the NER from time to time.*
>
> *Note: This Retailer Insolvency Event will cease to apply as a nominated pass through event on commencement of the National Energy Retail Law in Victoria.*

The proposed definition makes it clear that the retailer insolvency event will cease when the NECF is adopted, thereby removing any uncertainty about the legal effect of a note to the definition.

6 See, for example, AER, AusNet Services Final Decision 2016-20 – Pass through events, p. 17.

17.4.6 Electric Vehicle Uptake event

17.4.6.1 Background

Electricity vehicles (EVs) are gaining prominence globally as an alternative mode of transportation. While the penetration of EVs in Australia lags other countries,[7] uptake is expected to increase as EV technology improves. In addition, it is possible that policy and regulatory settings may be developed to facilitate growth in the EV sector.

EVs have the potential to transform the energy sector in several ways. They could represent a significant amount of useable energy storage, enable bi-directional energy flows with Vehicle-to-Grid capability, and promote advanced complementary technology.[8] When compared to petrol or diesel fuelled vehicles, EVs can also have significant consumer advantages:

- Low running costs: To cover the same distance, an EV typically costs between a quarter and a half when compared to the cost of fuel for a traditional vehicle. Most EVs also require less maintenance than traditional vehicles.
- Reduced or zero carbon emissions: Charging an EV from renewable energy, either from solar panels or from the network, can allow a significant reduction in carbon emissions.
- Convenience: An EV can be fully charged overnight at lower tariff rates, removing the need to visit a petrol station as a detour.

The uptake of EVs could have a significant impact on Australian electricity networks, including ours. The Senate Inquiry observed:

> *"An increased uptake of EVs would displace the transport sector's fuel source from petroleum to the electricity network, placing a range of unprecedented demands on the grid."*[9]

A significant increase in the uptake of EVs and the consequential demand for charging infrastructure will have implications for electricity network service providers. Firstly, it is likely to result in demand peaks and overall demand that exceeds historic levels. Eventually, DNSPs will be required to augment their networks or implement other significant non-network solutions to ensure their networks can safely and reliably meet the increased demand. The degree of augmentation required will depend on the pace and the coordination and management of an increasing penetration of EVs. For example, the number and capacity of the charging units required across the network will be determined by not only the rate of EV uptake, but also by the charging behaviour of EV drivers.[10] As the Australian Renewable Energy Agency (ARENA) states, EVs could create higher than expected demand and a flood of vehicles plugging in at the end of hot summer weekday could overwhelm the network.[11] Thus, charging behaviour and the size, prevalence and location of charging units will all directly affect how DNSPs mitigate and respond to network constraints.

While our current demand forecasts include modest growth in EV uptake,[12] this may be dramatically accelerated by a policy or regulatory change, which cannot currently be foreseen.

The Senate Inquiry found that the low numbers of EVs within the current Australian market is the result of the lack of direct incentives for consumers to purchase EVs and the absence of definitive

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7 Senate Select Committee on Electric Vehicles, January 2019, p. xv.

8 Demand Management Case Study, Electric Vehicle to Grid Trial, AusNet Services accessed via: https://www.ausnetservices.com.au/en/Residential/Electricity/Demand-Management.

9 Senate Select Committee on Electric Vehicles, January 2019, p. 40.

10 Australian Electric Vehicle Market Study, ARENA, May 2018.

11 Ibid.

12 AEMO, 2019 Electricity Statement of Opportunities, August, p. 39.

Federal Government policy. The Senate Inquiry recommended accelerating uptake by introducing national EV incentives and developing national standards and regulations for charging infrastructure and electricity grid integration.[13] It is evident from the Senate Inquiry's report that EV uptake, and therefore forecasts of uptake, are sensitive to whether an incentive or subsidy is offered.

International policies to phase out internal combustion engine (traditional) vehicles have become more prevalent in recent years. For example, the UK and France have already announced plans to phase out the sale of new petrol and diesel cars by 2040. To support these targets, the UK Government implemented and then subsequently scaled back a Plug-in Car Grant in 2018. This grant afforded consumers a significant discount on purchasing EVs and the change resulted in a 26.7% reduction in EV sales over a 12-month period, highlighting the sensitivity of EV uptake to government policy changes.[14] Norway has a target of all new vehicles sold by 2030 being EVs, which has contributed to the country having the largest per-capita fleet of EVs in the world.

We have identified several policy initiatives that Australian governments could use to influence EV uptake:

- Offering incentives, including registration and stamp duty concessions, tax concessions and rebates;
- Lowering the luxury car tax or import duties for EVs;
- Providing tax relief through fringe benefits tax or GST exemptions;
- Offering subsidies or rebates for EV buyers;
- Setting EV targets for government fleets;
- Tightening vehicle emission standards;
- Providing funding or training programs to upskill and train EV service technicians;
- Permitting importation of second-hand EVs into Australia; and
- Expanding the charging infrastructure.

The Federal Government's *National Strategy for Electric Vehicles*, released in February 2019 as part of Climate Solutions Package, promises to "coordinate action across governments, industry and urban and regional communities" to "ensure the transition to electric vehicle technology and infrastructure is planned and managed, so that all Australians can access the benefits of the latest vehicle technology."[15]

There remains, however, considerable uncertainty regarding the content and timing of EV-specific policies and, consequently, the substance of the legislative or regulatory obligations introduced to give effect to those policies. Absent this information, it is not possible to obtain reliable EV uptake forecasts or likely usage patterns, which in turn precludes us from being able to forecast the likely demand on our network or identify any new obligations we may become subject under. Thus, it is not possible to provide for these events in our expenditure forecasts.

There may be legislative changes or changes to (including the creation of) a regulatory framework for EVs that occur during the forthcoming regulatory period in a way that allows us to submit a cost pass through application for a regulatory change event. However, this pass-through event will not be available if:

- the change to the legal or regulatory obligation does not meet the definition of "regulatory obligation or requirement" in section 2D of the NEL (for example, flow on implications for the

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13 Senate Select Committee on Electric Vehicles, January 2019, pg. xi and xii.

14 Obtained from: https://www.drivingelectric.com/news/1440/electric-car-uk-consumer-interest-jumps-126.

15 Department of the Environment and Energy, *A National Strategy for Electric Vehicles*, February 2019, https://www.environment.gov.au/climate-change/publications/national-strategy-electric-vehicles.

network from instituting tighter vehicle emissions standards or revised procurement rules for government fleets);

- the increase in EV uptake is in response to a policy announcement or other event that is not accompanied by a change in the law or other regulatory instrument, but the change nevertheless results in a material increase in the cost to us of providing direct control network services.

This gap in the availability of cost pass through events creates a risk that an accelerated uptake of EVs will materially increase our costs, but the increase is not included in our approved expenditure allowances. Given that this is a high consequence risk that is extremely difficult to manage efficiently using alternative measures, and there is substantial uncertainty respect to cost impacts and timing, we consider that proposing a nominated cost pass through event is the most appropriate approach to manage this risk.

The ‘Electric Vehicle uptake event’ we are proposing will allow us to pass through costs associated with changes in government policy that drive EV uptake and which impact our electricity distribution network.

The significant uncertainty that exists with respect to the cost impacts and timing of EV uptake mean it is in the long-term interests of our consumers that we recover the prudent and efficient costs of the event through pass through arrangements, rather than ex-ante expenditure forecasts.

In support of this proposed nominated pass through event, we note that:

- an Electric Vehicle Uptake Event is not already covered by any of the categories of pass through events specified in clauses 6.6.1(a1)(1)-(4) of the NER;
- this type of event can be and is clearly identified;
- we cannot prevent this type of event from occurring and cannot substantially mitigate the cost impacts of this type of event (both prior to and after the occurrence of this type of event);
- the full range of costs that could potentially be incurred as a result of the occurrence of this type of event are not insurable;
- the occurrence of an Electric Vehicle Uptake Event is not foreseeable, has a low probability of occurrence but a high consequence or magnitude; and
- an Electric Vehicle Uptake Event is beyond the control of AusNet Services.

17.4.6.2 Proposed definition

Our proposed definition of an Electric Vehicle Uptake Event is:

> *An Electric Vehicle Uptake event occurs if, during the regulatory control period beginning on 1 July 2021:*
>
> 1. *The Commonwealth government or the government of Victoria announces a new or amended policy, program, initiative, scheme or other measure which is directed at increasing the uptake of electric vehicles; and*
>
> 2. *Following the announcement there is a sustained increase in the average energy consumption on AusNet Services’ network that is attributable to an increase in demand for electric vehicle charging; and*
>
> 3. *The cost of meeting the increase in consumption or unmet demand increases the cost of providing direct control services.*
>
> 4. *If, at the time the Electric Vehicle Uptake event occurs, AusNet Services cannot provide evidence of the actual or likely increase in costs that it will or is likely to incur in providing direct control services as a result of the Electric Vehicle Uptake event, AusNet Services may seek the approval of the AER later in the regulatory control period to pass through those amounts on the basis that the materiality threshold is met.*

17.5 Other event: Electricity Distribution Code (EDC) review

As noted above, the ESC's review of the Electricity Distribution Code (EDC review) could reasonably be expected to create new obligations or vary existing obligations on Victorian DNSPs. Although there is considerable uncertainty about the cost impacts this may have, we are not proposing a nominated cost pass through event because we envisage any changes will satisfy the regulatory change event. The remainder of this section provides further information regarding the EDC review.

The ESC recognised that the timing of the EDC review coincides with other industry initiatives such as the AER's "New Reg" trial. We are the first Australian utility business to trial this new customer engagement process that places customers at the heart of developing our expenditure plans. Our process saw us establish a Customer Forum to represent the perspective of our customers. The Forum has already allowed us to make great improvements to the customer centricity, efficiency and prudency of our regulatory proposal. We see the EDC review as an opportunity for us to share our experience of working with and learning from the Customer Forum and the NewReg process to modernise and refine the technical requirements and customer protections for all Victorian electricity customers.

The EDC sets minimum service standards and requirements for Victorian DNSPs that relates to customer protections, technical standards and the exchanging of information and business processes. In December 2019, the Essential Services Commission released its Draft Decision setting out its initial approach to proposing changes to technical standards so that the Code remains fit-for-purpose in the face of a rapidly changing energy system. The key areas of the review are:

- improving communication with customers affected by outages and, where customers have agreed, enabling digital communications in instead of written notifications sent in the mail;
- updating the Guaranteed Service Level (GSLs) scheme to align with national arrangements and better acknowledge the experience of customers suffering from the most frequent supply interruptions; and
- modernising and harmonising technical standards to better serve all customers, aligning voltage management thresholds with Australian Standards to provide a greater operating range for both the DNSPs and renewable energy generators.

Although appropriate expenditure associated with the review is likely to be needed in the 2022-26 regulatory period, significant uncertainty exists over the scope and cost that will be required. Rather than seek to pre-empt the legislative requirement, it is appropriate to use the pass through framework within the NER to ensure the right program is delivered and that the expenditure allowance is based on a reasonable estimate of the cost of that program, which will only be possible once further details of the EDC Review are completed.

Because of the uncertainty existing at the time of this proposal with respect to the outcome of the EDC review, we have elected not to include the potential costs of this event. While there is a risk that these costs will not exceed the materiality threshold, we consider that this approach is in the long-term interests of our customers.

Depending on the timeframe of the implementation of the legislative changes, we may be able to develop a forecast of the relevant expenditure prior to the finalisation of the AER's 2022-26 (FY) electricity distribution determination. However, at the time of this proposal, we consider that the uncertainty surrounding the EDC review should be treated using the regulatory change cost pass through event prescribed in the NER.

17.6 Application of pass through arrangements to alternative control services

Our nominated pass through events should apply to all direct control services (i.e. both standard control services and alternative control services) on the basis that the costs of providing alternative control services are also permitted to be considered as part of the cost pass through framework in rule 6.6.1.

18 Control mechanisms for standard control services

18.1 Key points

This section outlines how we propose to adjust prices for each year in the 2022-26 regulatory period and how tariffs comply with the requirements of the National Electricity Rules (NER) that relate to setting prices.

It addresses the following NER provisions:

- Compliance with the relevant control mechanisms [cl. 6.12.1(13)];
- Reporting and compliance with designated pricing proposal charges [cl. 6.12.1(19)];
- Reporting and compliance with jurisdictional scheme amounts [cl. 6.12.1(20)].

The transition to financial year regulatory years has required adjustments to be made to the form of control formulae set out in the AER's Framework and Approach paper. These adjustments were set out in a guidance note received from the AER on 2 December 2019.[206]

This chapter highlights further clarification on the treatment of some items that have been identified as requiring resolution during the review process.

18.2 Control mechanisms

To ensure we set prices in accordance with the regulatory regime, the AER's Framework and Approach paper (F&A) outlines mechanisms under which it controls the way prices are set.

We note that changes are required to ensure that there is an appropriate transition to financial year regulatory years. By adopting the formulae outlined in this Chapter, we consider we will meet the requirement of cl. 6.12.1(13) to demonstrate compliance with the relevant control mechanism.

18.3 Price control mechanism – direct control services

The AER's F&A sets out the price control mechanism that apply to direct control service tariffs for each of the services offered in the 2022-26 regulatory period and adjusted annually via an annual pricing proposal. We will submit annual pricing proposals by 31 March to apply to the regulatory years commencing 1 July.

The price control mechanism that will apply in the extension period is set out in Appendix 1C – Extension Period Revenues.

The AER's price control mechanisms include:

- a revenue cap for standard control services;
- a revenue cap for type 5, type 6 and smart regulated metering for 'installation, operation, repair & maintenance, and replacement' and 'collection of meter data, processing and storage of meter data, and provision of access to meter data' services; and
- price caps for each individual service for alternative control services.

18.4 Revenue cap for standard control services

A revenue cap for standard control services means that we have no scope to recover more revenue from our tariffs than the total revenue allowed by the AER. Where tariff levels and actual

[206] Email: Subject: Price control formulas for Victoria 2021 extended period and 21-26 regulatory control period [SEC=UNCLASSIFIED], 2 December 2019.

demand levels result in an under- or over-recovery of revenue in any one year (year t-2), it must be adjusted in the tariffs that apply two years later (year t) to correct this.

Table 1.1 – Revenue cap formulae

Revenue cap formulae		
1	$TAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$	i=1,...,n and j=1,...,m
2	$TAR_t = AAR_t + I_t + B_t + C_t$	t = 1, 2, 3, 4 and 5
3	$AAR_t = AR_t \times (1 + S_t)$	t = 1
4	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + S_t)$	t = 2
5	$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$	t = 3, 4, 5

where:

TAR_t	is the total annual revenue in year t.
p_t^{ij}	is the price of component 'j' of tariff 'I' in year t.
q_t^{ij}	is the forecast quantity of component 'j' of tariff 'i' in year t.
t	is the regulatory year.
AR_t	is the annual smoothed revenue requirement in the Post Tax Revenue Model (PTRM) for year t.
AAR_t	is the adjusted annual smoothed revenue requirement for year t.
I_t	is the sum of incentive scheme adjustments in year t. To be decided in the distribution determination.
B_t	is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the unders and overs account. To be decided in the distribution determination.
C_t	is the sum of approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER. It will also include any end-of-period adjustments in year t. To be decided in the distribution determination.
S_t	is the s-factor for regulatory year t.
ΔCPI_t	CPI for the regulatory control period will change to

$$\Delta CPI_t = \frac{CPI_{Dec\,t-1}}{CPI_{Dec\,t-2}} - 1$$

This will reflect most recent CPI figures at the time of pricing proposals

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

Notes:

- For t=1=2021/22, AR_t is set in the relevant PTRM
- For t=1=2021/22, C_t will incorporate any cost pass-throughs that would have applied for the interregnum period as well as the standard application for the current year
- For the new regulatory control period, the new STPIS guideline will be implemented from year 3, and is reflected in these price control formulas. In years 1 and 2 (included STPIS relating to the 2021 extended period) the s-factor will be applied as per previous guideline (% format). In years 3-5 the s-factor will be applied as per the new guideline ($ format).
- For t=1,2, $I_t = F_{t-3} + D_t$ i.e. the f factor on a three year lag, and any demand management incentives applicable (DMIS, DMIAM, etc.)
- For t=3,4,5, $I_t = S_{t-2} + F_{t-3} + D_t + H_{t-2}$
- For t=2=2022/23, S_t will incorporate the S factor relevant to performance in both the 2020 period and the 2021 interregnum period,
- For t=1=2021/22, the unders/overs accounts (for SCS, metering, TUoS, and JUoS) will incorporate four periods: 2019 actuals, 2020 estimates, 2021 interregnum estimates, and 2021/22 forecasts
- For t=2=2022/23, the unders/overs accounts (for SCS, metering, TUoS, and JUoS) will incorporate four periods: 2020 actuals, 2021 interregnum actuals, 2021/22 estimates, and 2022/23 forecasts
- For t=3,4,5, the unders/overs accounts (for SCS, metering, TUoS, and JUoS) will revert back to the standard three periods: t-2 actuals, t-1 estimates, and t forecasts.
- Incentive scheme factors have been omitted from the side constraint mechanism, as dictated by NER 6.18.6(d)(1) which states that both cost-pass throughs and incentive schemes should be disregarded from the side constraint mechanism.

Table 1.2 – Side constraint formulae

Side constraint formula
$\dfrac{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_t^{ij} q_t^{ij})}{(\sum_{i=1}^{n}\sum_{j=1}^{m} d_{t-1}^{ij} q_t^{ij})} \leq (1+\Delta CPI_t) \times (1-X_t) \times (1+2\%) + B_t'$

where:

d_t^{ij} is component 'j' of tariff 'i' for year t

d_{t-1}^{ij} is the price charged for component 'j' of tariff 'I' in year t–1

q_t^{ij} is the forecast quantity of component 'j' of the tariff class in year t

ΔCPI_t CPI for the regulatory control period will change to

$$\Delta CPI_t = \frac{CPI_{Dec\,t-1}}{CPI_{Dec\,t-2}} - 1$$

This will reflect most recent CPI figures at the time of pricing proposals

X_t is the X-factor in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the distribution determination.

B_t' is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the unders and overs account. To be decided in the distribution determination.

We have adopted the control mechanisms as set out in the AER's F&A, with amendments made to allow for a transition to a financial year regulatory control period. This mechanism allows for the modification of elements in the formula as they are identified during the price reset consultation phase.

18.5 Items to be decided in the final decision – standard control services

'I' term

We note that there are number of incentive schemes in the 2022-26 regulatory period. The relevant incentive schemes for the i-factor are the:

- Victorian Government's f-factor scheme active in the 2022-26 regulatory period.
- The AER's Customer Satisfaction Incentive Scheme (CSIS).[207]
- The s-factor as applicable under the revised STPIS (noting this is incorporated as a % adjustment under the previous scheme).

207 This AER published the draft CSIS in December 2019. The proposed inclusion of the CSIS in the i factor assumes a final scheme is made by the AER.

'B' term

License fees charges by the Victorian Essential Service Commission have previously been recovered through the B term. We propose to continue this treatment in the 2022-26 regulatory period.

We note that we anticipate a significant increase in the annual levy from Energy Safe Victoria. We propose to treat these charges in the same manner and recover it through the B term. We do not consider it is appropriate for us to be exposed to either a financial penalty or reward for a cost that it has no ability to control. As the ESV levy is determined exogenously and is identical in nature to the ESC's licence fee we consider these costs should also be treated as a pass through in the annual pricing proposal. This is consistent with the framework that has been applied to the ESC's licence fee.

We propose to include a true-up for the net present value of under or over recovery of revenue in the t-2 year. The method to achieve this is to create the present value of actual revenue equal to the present value of revenue allowable.

B_t is the sum of

1. **the recovery of license fee charges by the Victorian Essential Services Commission indexed by one and a half years of interest, calculated using the following method:**

$$L_{t-1} \times (1+WACC_t) \times (1+WACC_{t-1})^{1/2}$$

where:

L_{t-1} are the licence fees paid by DNSP to the Victorian Essential Services Commission in the financial year ending in June of regulatory year t–1

2. **the recovery of levies charged by the Energy Safe Victoria indexed by one and a half years of interest, calculated using the following method:**

$$V_{t-1} \times (1+WACC_t) \times (1+WACC_{t-1})^{1/2}$$

where:

V_{t-1} are levies charged by the Energy Safe Victoria in the financial year ending in June of regulatory year t–1

3. **adjustments for the unders and overs account**

Calculation of CPI

In various price control formula, CPI is used to escalate revenues and prices to nominal dollars. In the framework and approach paper, the AER indicated it would advise the method for determining CPI as a part of the final determination

We propose the method for determining this escalator inset below.

$$\Delta CPI_t = \frac{CPI_{Dec\ t-1}}{CPI_{Dec\ t-2}} - 1$$

Where $CPI_{Dec\ t\text{-}1}$ is ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1 and

$CPI_{Dec\ t-2}$ is the ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

The use of December quarter CPI data is proposed, rather than the June quarter adopted in the AER's F&A, due to the change in the timing of regulatory years from a calendar year to an Australian Financial year.

X-factor adjustment

The X-factor is determined by the Post Tax Revenue Model (PTRM). The value of X-Factor is to be amended annually to adjust for the trailing average return on debt. This is be decided in the distribution determination.