FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Overview

April 2021

AUSTRALIAN ENERGY REGULATOR

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Executive summary

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. This final decision sets out the amount of money AusNet Services can collect from electricity consumers for using its network over the 2021–26 regulatory control period.

AusNet Services owns and operates one of the five electricity distribution network service providers in Victoria and services around 737 000 customers across the east of Victoria, from the edge of Melbourne to the border with New South Wales. On 31 January 2020, AusNet Services submitted its regulatory proposal for the five year regulatory control period commencing 1 July 2021. On 3 December 2020, AusNet Services submitted a revised proposal in response to the AER's draft decision of 30 September 2020.

AusNet Services demonstrated a commitment to putting its consumers at the centre of its decision-making through its negotiations with its Customer Forum (part of our New Reg trial) which had a strong influence on its initial and revised proposals. As a consequence of the quality and outcomes of this engagement, our draft decision accepted most of AusNet Services' initial proposal including its capital expenditure (capex) proposal which was 19 per cent below its current regulatory period spend subject to adjustments related to changes in economic conditions.

In its revised regulatory proposal, AusNet Services went beyond the requested updates and proposed additional capex. Based on our rigorous assessment of the capex categories that had revised forecasts beyond what we assessed in the draft decision, we reduced AusNet Services' revised capex forecast particularly for new connections. We accepted the majority of proposed operating expenditure (opex) in our draft decision and AusNet Services revised proposal raised bushfire liability insurance premium forecast cost increases, an important issue. We worked collaboratively to determine an efficient forecast insurance premium amount and have included it in the total opex we approved.

We are satisfied that the amount of money we have allowed AusNet Services to recover from consumers is no more than necessary to replace ageing infrastructure and operate its network in a safe and reliable manner in the long term interest of consumers.

AusNet Services can recover $3470.5 million ($ nominal) from its consumers over the 2021–26 regulatory control period. In real terms, this is 1.6 per cent higher than the revenue allowed for in our 2016–20 final decision and leads to higher network charges for AusNet Services' consumers from the next regulatory control period.

The revenue we allow forms the distribution network component of retail electricity bills, making up about 34 per cent of a standard residential bill (39 per cent for small businesses).

We estimate that AusNet Services' distribution network and metering charges in the first year of the 2021–26 regulatory control period will increase by $27 (1.6 per cent) for residential consumers and $95 (1.2 per cent) for small business consumers, relative to charges in 2020. Thereafter, these charges are estimated to increase by $4 (0.2 per cent) and $21 (0.3 per cent) per year respectively.

We are mindful that estimated distribution network charges for AusNet Services' consumers will increase while those for the other Victorian distribution businesses decrease. This increase does not mean that AusNet Services' consumers are paying more than necessary, rather the differences between businesses do sometimes result in differing outcomes at a point in time.

AusNet Services' annual revenue requirement for the 2021–26 regulatory control period reflects a real increase relative to its current regulatory control period (2016–20). This increase is largely driven by increased regulatory depreciation being recovered from consumers over 2021–26 regulatory control period because AusNet Services spent money on capex in the current (2016-20) period which increased its asset base. This asset base growth, one of the highest relative to the other Victorian distribution businesses, is driven by the investments it made to address bushfire risk. While AusNet Services' asset base has grown, it still spent less than the efficient and prudent level of total forecast capex approved in our 2016 final decision. Money spent on capex is added to the asset base and recovered from consumers through return of (depreciation) and on (cost of capital) capital.

While the current regulatory control period saw a high asset base growth impacting the network charges in the next regulatory period, in this final decision AusNet Services' forecast capex is 21.3 percent lower than what it spent over the current regulatory period. This should result in its asset base stabilising over the 2021–26 period to one of the lowest asset base growth levels relative to other Victorian distribution businesses and thus benefit consumers in future periods through lower return of and on, capital recovered through network charges. Customer Forum negotiation played a significant part in this outcome. AusNet Services' actual opex in the current regulatory period is also below the amount we forecast in our 2016 final decision. Consumers benefit from this lower revealed amount because it is used as the starting point to forecast the efficient level of opex in the next regulatory period.

We note that $12 of the estimated $27 increase in the first year of the 2021–26 regulatory control period is due to AusNet Services' Advanced Metering Infrastructure (AMI) charges (metering charges). This first year (2021–22) increase is a result of us applying the revenue recovery profile which was the outcome of the AER's 2018 AMI decision. AusNet Services' profile differs from the other distributors and therefore they do not have an increase in 2021–22. This first year increase occurs as AusNet Services' revenue recovery for metering services returns to trend after the adjustments relating to the AER's 2018 AMI decision. The 2018 AMI decision resulted in a larger adjustment for AusNet Services than the other Victorian businesses, with a revenue recovery profile being set for three years to account for this outcome, in contrast to the one year adjustment for the other businesses.

Our estimate of AusNet Services' first year bill increase is also affected by adjustments for previous revenue over recoveries (or B-factor) which reduced its revenue in 2020. This reduction, which is the highest among the Victorian distribution businesses, accentuates the size of the revenue increase from 2020 to 2021–22 and accounts for around $5 of the standard control service bill increase of $15 in 2021–22.

Finally, our approach to estimating network charges uses the change of revenue we allow divided by demand (energy consumption) forecast. This means a lower demand forecast results in a higher price. AusNet Services submitted that for reasons including energy efficiency improvements, growth in solar PV and changes in consumer behaviour, its demand is forecast to decrease over the 2021–26 regulatory control period. Whereas the other Victorian distribution businesses' demand is forecast to increase. Consumers have already seen changes from last years prices because new distribution network charges were passed through to Victorian consumers for six months on 1 January 2021 with the introduction of the *National Energy Legislation Amendment Act 2020* (Vic) (NELA Act).[1] In making this final decision we updated a range of components that were used to calculate the lower distribution network charges that were passed on to consumers on 1 January 2021. In particular, we updated the rate of return to reflect movements in interest rates and our revised estimate of expected inflation. As a result of these updates, distribution network charges starting 1 July 2021 will be 6.4 per cent higher than the distribution network charges that were set on 1 January 2021, and 1.6 per cent higher than the distribution network charges that were in place in 2020. We still need to consider other factors that will impact the final distribution network charge that consumers and business pay – these will be considered when we assess AusNet Services' annual pricing proposal.[2]

In making this final decision we have had regard to a range of sources including AusNet Services' revised proposal, submissions received, as well as analysis undertaken and published by us.

AusNet Services' engagement with consumers

A key development of the 2021–26 determination has been the positive shift by the distributors in relation to improved consumer engagement.

In recognition of this evolution, in our draft decision, we developed a framework, to assess the consumer engagement activities of the Victorian distributors which is replicated at appendix C.[3] This framework informed how we viewed this engagement in

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1 The intention of the NELA was to change the timing of the regulatory control period for electricity distribution networks from a calendar year basis to a financial year basis, to align with other NEM states. We separately assessed the total allowed revenue for AusNet Services for the six month period from 1 January 2021 to 30 June 2021. See our final decision of 28 October 2020 at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/aer-position#step-72919.

2 See Pricing proposals & tariffs webpage on the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs.

3 AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview, September 2020*, Table 7, p. 46.

relation to the initial expenditure proposals and our overall assessment. Stakeholder submissions provided positive support and feedback on this approach and we plan to undertake further stakeholder consultation on the future design of the framework following completion of the Victorian reset.

We recognise that consumer engagement can take many different approaches and to assist in the final decision we have continued to refer to the framework as outlined in the draft decision, which provides a benchmark for the discussion. We acknowledge that each distributor approached engagement differently and AusNet Services demonstrated this innovation through the New Reg trial. This engagement drove greater levels of involvement by consumers, and sought their feedback and influence at a greater level of detail, over a broad range of topics. One notable innovation arising from negotiations with the Customer Forum is the Customer Service Incentive Scheme, which provides an incentive for AusNet Services to continue to monitor and improve the customer experience.

AusNet Services initial proposal included selected components of its capital expenditure that were negotiated with its Customer Forum. Having regard to the quality and outcomes of this engagement, and our top-down analysis, our draft decision accepted its expenditure forecast, subject to a number of adjustments, largely due to changed economic conditions. In response to our draft decision, the Customer Forum reaffirmed its support for the positions it took in its final engagement report.[4] In the revised proposal, AusNet Services included a number of new expenditure items, which were not subject to our previous assessment or negotiated in the initial discussions with the Customer Forum. We maintained our top-down assessment from the draft decision, but also conducted a bottom-up assessment of the additional capex and opex step change for insurance premiums.

Consumer engagement models will continue to mature over time. Ongoing development of the framework will support businesses to develop proposals that are prudent and efficient, and demonstrate the express views and support of consumers.

Ensuring consumers pay no more than necessary for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process. We must assess whether a business' proposal is a reasonable and realistic forecast of how much money it needs for the safe and reliable operation of the network. It also involves encouraging distributors to explore how they can provide better services at lower cost through a range of incentive schemes.

Our final decision finds AusNet Services' opex acceptable but the reproposed capex which is higher than our draft decision, not acceptable.

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4 CF final engagement report; AusNet Services RRP, Appendix #A – Customer Forum Memo – December 2020, p.1-3.

Our final decision total forecast capex amount is $1,384.1 million which is about 3 per cent lower than AusNet Services' revised proposal.

AusNet Services' initial capex proposal was 19 per cent below its current regulatory period capex and we accepted it subject to adjustments to address changes in economic conditions, reclassification of some expenditures and corrections. Our top down and bottom up assessments found the initially proposed capex largely acceptable with the exception of adjustments for real cost escalation and connections to better account for COVID-19 effects.

AusNet Services' acknowledged us accepting its initial capex proposal but redeveloped a few capex category level forecasts leading to a total capex amount that was 5 per cent higher than our draft decision.

We carefully assessed the proposed capex changes and found that they are mostly acceptable except for how AusNet Services developed its net connections capex amount. Our analysis resulted in a $48 million increase in capital contributions leading to a corresponding decrease in the net connections capex that is included in our total capex forecast. We also reduced AusNet Services' rapid earth fault current limiter (REFCL) compliance related capex by $4 million as some of the program could prudently be deferred to beyond the 2021–26 regulatory control period.

Our final decision accepts AusNet Services' updated revised total opex proposal of $1238.7 million ($2020–21). This is because it is not materially different to our alternative opex estimate of $1226.8 million ($2020–21). We acknowledge there is some uncertainty with future insurance premium forecasts, but believe businesses should be incentivised through our framework to achieve efficient outcomes and lower prices for consumers in subsequent periods by including these costs in the total opex forecast. AusNet provided a higher updated revised proposal with a step change of $45.1 million ($2020–21) for these future premium increases. We considered this was reasonable and have accepted it as a part of its total opex proposal. As a result we have not accepted the proposed insurance premium event nominated cost pass through for the 2021–26 regulatory control period.

Having reviewed an application by CitiPower, Powercor and United Energy, we determined that the annual payments made by the Victorian distributors to Energy Safe Victoria (ESV) are a jurisdictional scheme.[5] This final determination includes a decision on how AusNet Services is to report to the AER on its recovery of amounts for the scheme and on adjustments made in pricing proposals to account for over or under recovery. For all Victorian distributors, it will now be recovered through annual prices rather than the allowed (opex) revenue we set in our decision.

5 See https://www.aer.gov.au/communication/aer-makes-determination-on-cpus-application-for-a-jurisdictional-scheme.

Transition of the energy system

Facilitating the transition of the energy system is a key theme for this Victorian regulatory determination process. Mechanisms such as expenditure to physically accommodate greater solar exports, tariff price signals and demand management initiatives can help. We consider the transition of the energy system so important that we have made incentivising networks to become platforms for energy services a strategic objective in our regulation of networks.

We accepted AusNet Services' initial proposal on the amount of capex required to facilitate and integrate distributed energy resources (DER) on its network. Our decision supports AusNet Services accommodating solar PV growth on its networks to achieve consumer expectations regarding the Victorian Government's Solar Homes program.

We have engaged extensively with stakeholders in the development of consistent DER integration expenditure guidelines. We published CSIRO and CutlerMerz's final value of DER (VaDER) methodology study in November 2020. However, the Australian Energy Market Commission (AEMC) recently published draft rule changes which have implications for our DER integration expenditure guideline, which will delay its finalisation.[6]

Cost reflective network tariffs also have an important part to play in the energy transition by incentivising the location and use of DER to optimise benefits to consumers and networks.

We are encouraged by the Victorian distributors' efforts to progress network tariff reform during the 2021–26 regulatory control period. The distributors moved from opt−in to opt−out assignment to the new default time of use tariff for consumers receiving a new meter or who upgrade their connection. By working collaboratively with their stakeholders[7] they developed small consumer tariff proposals with aligned, more targeted peak charging windows. We are also pleased to see the Victorian distributors reassigning small consumers on legacy cost reflective tariffs to a new and more targeted default time of use tariff.

We engaged rigorously with the electric vehicle (EV) sector and heard many different perspectives. We encourage electric vehicle charging station and energy storage proponents to engage with the Victorian distributors on tariff trials. We see trials as a valuable way of proving out new and innovative service models to inform future network tariffs.

Our view is that it is important that EV charging stations face cost reflective network tariffs to minimise new network investment that increases costs for all consumers. Consistent with our view, charging stations which install load limiting devices can

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6 See https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources.

7 This included retailers and jurisdictional government entities

access alternative cost reflective tariffs. Our final decision also makes clear, consistent with Victorian Government policy, that once small consumers with an EV are identified they must be assigned to a cost reflective network tariff.

We consider storage assets should both contribute to recovery of network costs commensurate with their network use and see cost reflective price signals to guide their operation. Our final decision on stand-alone grid scale storage connected to the Victorian networks is to assign such consumers according to the usual tariff classes unless they are only providing network support services. Regardless, ownership of storage assets should not affect tariff class assignment.

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

1 Our final decision

Our final decision allows AusNet Services to recover a total revenue of $3470.5 million ($ nominal) from its consumers from 1 July 2021 to 30 June 2026. AusNet Services is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

Our final decision for AusNet Services determines the total revenue it can recover from consumers for the provision of common distribution services (standard control services (SCS)). This forms the basis of AusNet Services' distribution tariffs for the 2021–26 regulatory control period. AusNet Services' Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from consumers.

AusNet Services also provides alternative control services (ACS), the costs of which are recovered only from users of those services. These costs are considered separately to our building block determination.[8] Our final decision sets out the prices AusNet Services is allowed to charge consumers for the provision of ACS: ancillary network services, public lighting and total revenue for metering. AusNet Services has not proposed to provide any services on a negotiated basis in the 2021–26 regulatory control period.[9]

We have taken AusNet Services' consumer engagement into account in developing our final decision. More information is provided in section 3.

1.1 What's driving revenue?

Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditure) in real terms (using 2020–21 as a common year) to reveal the underlying cost trends over a number of years or regulatory control periods. The numbers presented in this overview are in real 2020–21 dollars unless otherwise noted. Some aspects of our decision are presented in nominal terms to be consistent with the National Electricity Rules (NER) and to enable consumers to see the full impact of our determination inclusive of expected inflation.

The total revenue allowance in this 2021–26 final decision is 1.6 per cent higher than the revenue provided for in our 2016–20 final decision in real terms. Although real revenues fall throughout the 2021–26 regulatory control period, they do not fall at such a pace that prevents an overall increase in real revenues when comparing across the two periods as a whole. Figure 1 shows real revenue stays flat from 2020 levels to the first year of the next regulatory control period. After that, AusNet Services' revenue allowance falls in real terms by 1.7 per cent per year.

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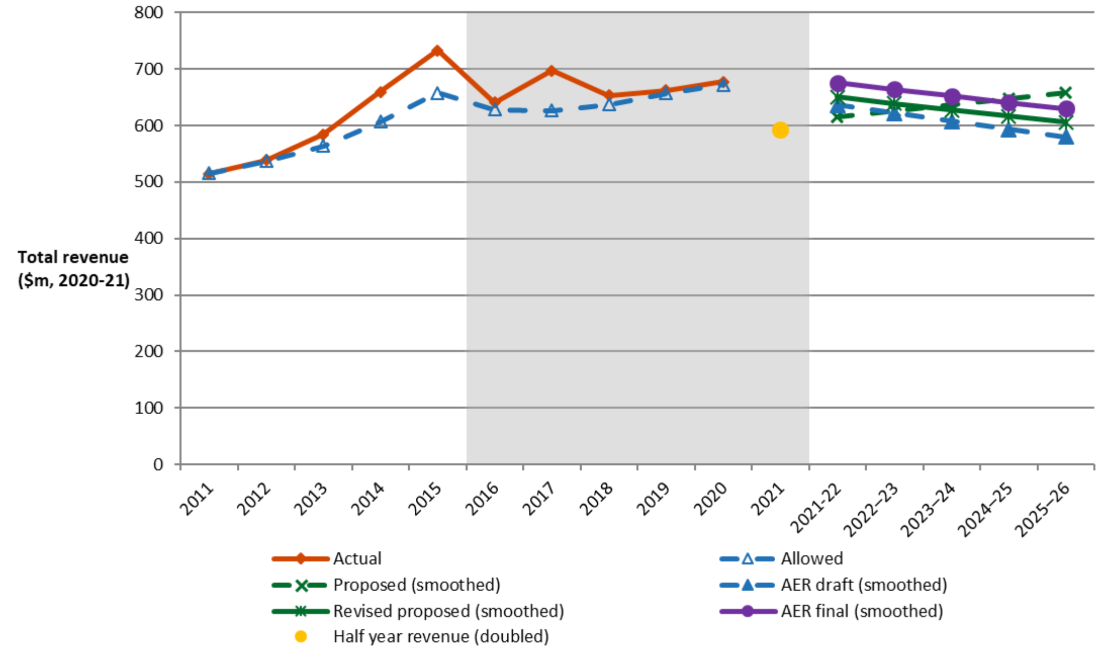
8 We discuss alternative control services in Attachment 16 to this final decision.

9 Our distribution determination for AusNet Services includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because AusNet Services has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2021–26 regulatory control period.

Figure 1 Revenue over time ($ million, 2020–21)



Source: AER analysis.

Figure 2 highlights the key drivers of the change in AusNet Services' allowed revenue from the 2016–20 regulatory control period compared to what we expect in the 2021–26 regulatory control period. It illustrates that the largest driver of change is the return of capital building block which increases revenues by $305.1 million in the 2021–26 regulatory control period compared to the 2016–20 period. Because AusNet Services added new equipment to its network over the last five years, its regulatory asset base (RAB) is increasing and so has its depreciation. AusNet Services' increase in depreciation is also affected by lower expected inflation over the 2021–26 regulatory control period and also the accelerated depreciation of certain assets.[10] The return on capital is the next most significant driver. The nominal rate of return has decreased from around 6.31 per cent in the 2016–20 regulatory control period to 4.83 per cent for the 2021–26 period. As a result, the total cost of capital had reduced by $237.1 million.[11] In 2019, we reviewed how we calculate the cost of corporate tax and made changes to our approach to align with the latest rulings of the Australian Tax Office. This means we expect the cost of corporate tax for AusNet Services will be lower than it was in the past. As a result, Figure 2 also shows a decrease in the cost of corporate tax building block of $148.3 million.[12] Revenue adjustments that are largely related to our Capital expenditure sharing scheme (CESS) and Efficiency benefit sharing scheme (EBSS) are also a significant driver of revenues and increases revenues by $174.8 million compared to the 2016–20 period. Forecast opex has reduced by $49.0 million compared to the 2016–20 regulatory control period.[13]

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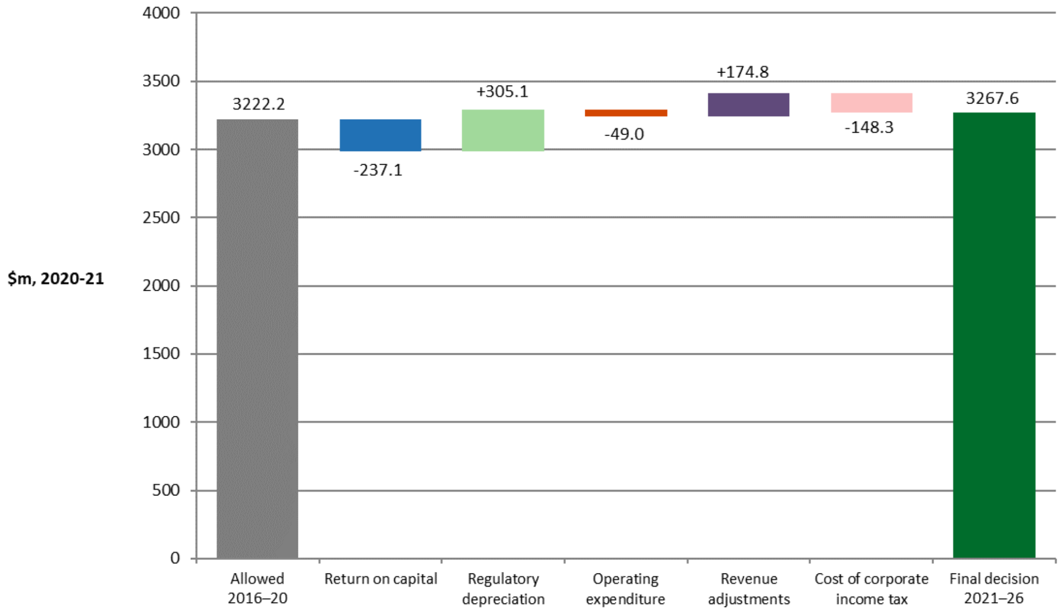
[10] Please see section 2.3 for further details.

[11] The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has decreased by a similar amount. Please see section 2.2 for further details.

[12] Please see section 2.6 for further details.

[13] Please see section 2.5 for further details. This comparison is based on converting 2016–20 forecast opex for inflation to 2020–21 dollar terms using lagged CPI.

Figure 2 Change in revenue from 2016–20 to 2021–26 ($ million, 2020–21)

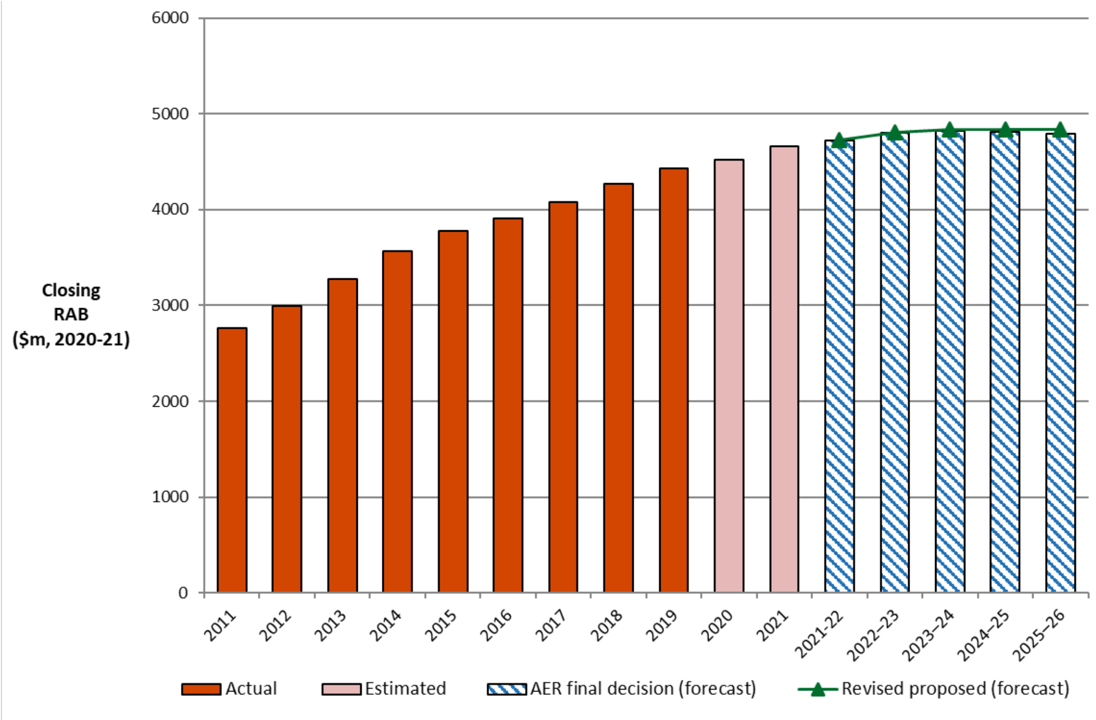


Source: AER analysis.

Figure 3 compares our final decision forecast RAB to AusNet Services' revised proposed and actual RAB. AusNet Services proposed to reduce its capex going forward which would have led to its RAB being stabilised. We reviewed this proposal carefully and have mostly accepted its forecast spending subject to a few reductions. AusNet Services' RAB is forecast to increase by around 2.8 per cent in real terms over the 2021–26 regulatory control period. In the previous 2016–20 regulatory control period, its RAB increased by 19.7 per cent in real terms.[14]

[14] Please see section 2.1 for further details.

Figure 3 Value of AusNet Services' RAB over time ($ million, 2020–21)



Source: AER analysis.

1.2 Differences between our final decision and revised proposal

The total revenue we are allowing in our final decision is $3470.5 million ($ nominal) for the 2021–26 regulatory control period. This is $103.4 million or 3.1 per cent higher than AusNet Services' revised proposal of $3367.1 million.

We have largely accepted AusNet Services' revenue proposal and the difference is due to our updating of the proposed building block amounts using more recent information.

The biggest contributor to the difference between our final decision revenue and AusNet Services' revised proposal is regulatory depreciation. Our estimate of the regulatory depreciation of $850.4 million is $81.6 million ($ nominal) or 10.6 per cent higher than AusNet Services' revised proposal estimate of $768.7 million ($ nominal). The main driver of this difference is the lower expected inflation which resulted from our inflation review. Our latest version of the Post-tax revenue model (PTRM) (version 5) released in April 2021 amended the way we estimate inflation, in order to improve our estimation in periods of economic instability or sustained periods of low or high inflation.[15] Our final decision estimates expected inflation of 2.00 per cent, which is lower than AusNet Services' estimate of expected inflation of 2.37 per cent.

We determine the return on capital of $1103.2 million ($ nominal), is $36.5 million or 3.4 per cent greater than the $1066.6 million in AusNet Services’ revised proposal.

[15] AER, *Final position paper - Regulatory treatment of inflation*, December 2020, p. 6.

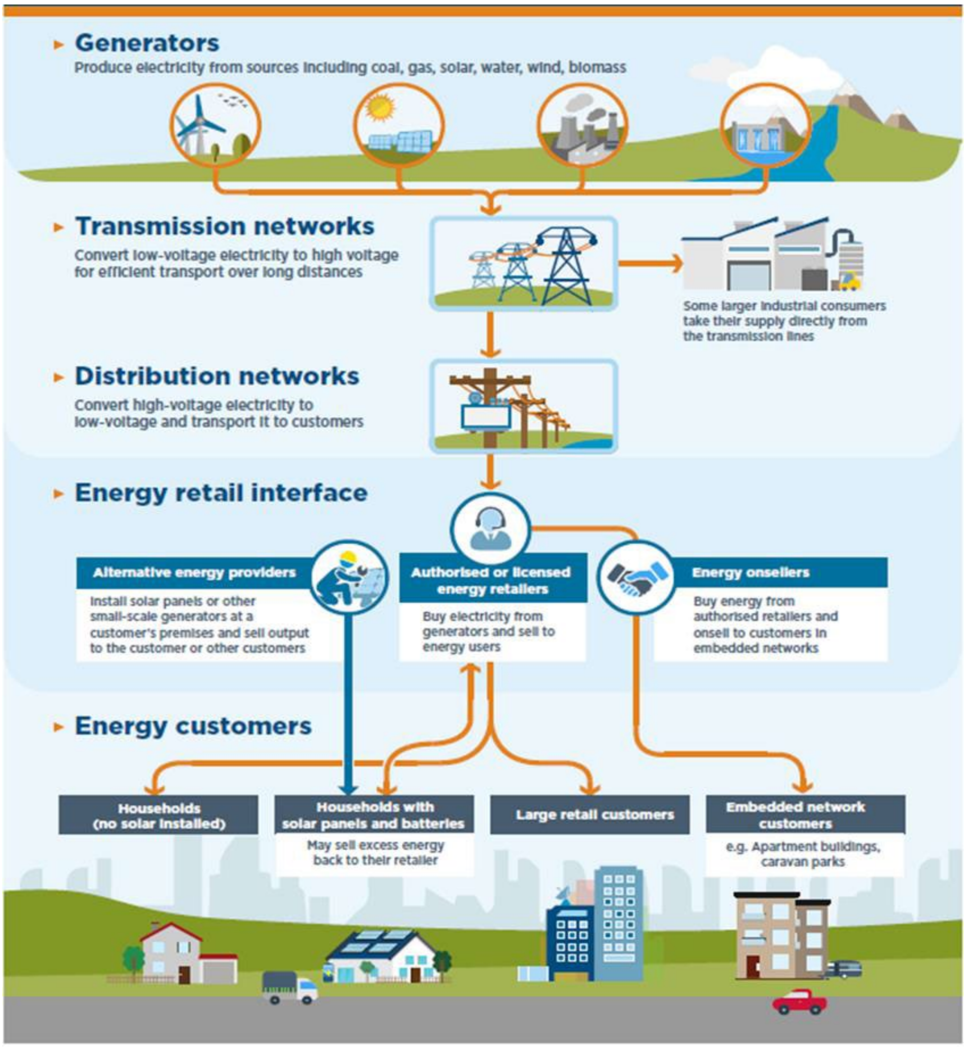
This is driven by our estimate of AusNet Services' nominal return of equity of 5.12 per cent, which is greater than the estimate of 4.59% in AusNet Services' revised proposal.

Based on evidence before us, we are not satisfied that AusNet Services' revised proposed forecast capex of $1432.9 million ($2020–21) reasonably reflects prudent and efficient costs. Our substitute capex forecast is $48.8 million ($2020–21) or 3.4 per cent lower, than the revised proposal. This leads to a lower forecast RAB than AusNet Services' revised proposal.

1.3 Expected impact of our final decision on electricity bills

AusNet Services' distribution network SCS charges make up around 34 per cent of the total residential bill and 39 per cent of the total small business retail electricity bill. Our decision also covers charges for revenue-capped metering services (that form part of ACS) and these costs are included in this estimated bill impact analysis. Other components of the electricity bill include wholesale electricity costs, retail costs and environmental policy costs. Figure 4 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to customers by their chosen electricity retailer.

Figure 4 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our allowed revenue determination. These prices are indicative and might vary with changes in demand.

Table 1 shows the estimated average annual impact of our final decision for the 2021–26 regulatory control period on electricity bills for residential and small business customers.

We estimate the expected impact on bills by varying the distribution charges in line with our 2021–26 final decision, while holding all other components constant. This approach isolates the effect of our final decision on distribution network tariffs from other parts of the bill. However, this does not mean that other components will remain unchanged across the regulatory control period.[16]

Under the final decision we estimate that compared to 2020 charges, the distribution network and metering charges ($ nominal) in AusNet Services' area:

- for an average residential consumer would:
  - increase by $27 (1.6 per cent) in the first year of the 2021–26 regulatory control period
  - increase on average by $4 (0.2 per cent) for each of the remaining four years of the 2021–26 regulatory control period.
- for an average small business consumer would:
  - increase by $95 (1.2 per cent) in the first year of the 2021–26 regulatory control period
  - increase on average by $21 (0.3 per cent) for each of the remaining four years of the 2021–26 regulatory control period.

[16] It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since AusNet Services operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2021–26 regulatory control period.

Table 1 Estimated contribution to annual electricity bills for the 2021–26 regulatory control period ($ nominal)

	2020	2021–22	2022–23	2023–24	2024–25	2025–26
AER Final decision						
Residential annual bill	1666[a]	1693	1698	1702	1706	1710
Annual change (per cent)[c]		27 (1.6%)	5 (0.3%)	4 (0.3%)	4 (0.2%)	4 (0.2%)
Standard control services		15	5	4	3	3
Metering		12	0	0	0	0
Small business annual bill	7945[b]	8040	8066	8087	8106	8124
Annual change (per cent)[c]		95 (1.2%)	26 (0.3%)	21 (0.3%)	19 (0.2%)	18 (0.2%)
Standard control services		83	26	21	19	17
Metering		12	0	0	0	0
AusNet Services revised proposal						
Residential annual bill	1666[a]	1670	1677	1683	1688	1693
Annual change (per cent)[c]		4 (0.2%)	7 (0.4%)	6 (0.3%)	6 (0.3%)	5 (0.3%)
Standard control services		–6	6	6	5	5
Metering		10	0	0	0	0
Small business annual bill	7945[b]	7922	7957	7988	8018	8046
Annual change (per cent)[c]		–23 (–0.3%)	35 (0.4%)	31 (0.4%)	29 (0.4%)	28 (0.3%)
Standard control services		–33	35	31	29	28
Metering		10	0	0	0	0

Source: AER analysis; Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision*, 18 November 2019, p. 76.

(a) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 4000 kWh for residential customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(b) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 20000 kWh for small business customers in Victoria. This is then indexed by CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2020 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by AusNet Services. Actual bill impacts will vary depending on electricity consumption and tariff class.

AusNet Services used a revenue per customer approach to measure bill impacts, whereas our approach is different, leading to some differences in the forecast impacts. The revenue per customer approach uses the change of revenue divided by customer numbers. Our approach uses the change of revenue divided by energy consumption. The concepts are closely related as forecast increases in customer numbers will also be reflected in greater forecast energy consumption. Forecast energy consumption, however, can also change due to any changes in the average level of energy each customers is forecast to consume. In this regard, using energy consumption is seen as a way to capture more potential sources of bill changes from one year to the next. This matter is discussed further in attachment 1.

Our calculated bill impact assessment for AusNet Services shows a $44 increase from 2020 to 2025–26. However, our similar bill impact assessments for each of the other Victorian distributors show reductions. There are several factors for this difference including:

- AusNet Services' aggregate consumption profile is forecast to decrease over the 2021–26 regulatory control period, whereas for each of the other Victorian distributors it is forecast to increase. In our approach, a lower energy throughput results in a higher price path. AusNet Services' Annual Revenue Requirement (ARR) for the 2021–26 regulatory control period reflects a 1.4 per cent real increase relative to the ARR for the 2016–20 regulatory control period whereas for each of the other Victorian distributors, there is a period to period real reduction. Figure 2 shows the relative change to each revenue building block between the 2016–20 and 2021–26 regulatory periods. On the other hand, AusNet Services' RAB growth over the 2016–21 period of 23.3 per cent (Figure 3) is the second highest among the Victorian distributors and this is a factor in AusNet Services having a period-to-period reduction in return on capital which is (in percentage terms) the second-lowest among the Victorian distributors. This relatively high 2016–21 RAB growth along with a large amount of accelerated depreciation in the 2021–26 regulatory control period also contributes to AusNet Services having the highest period-to-period increase (in percentage terms) to regulatory depreciation among the Victorian distributors. While higher depreciation increases revenue in the period in which it occurs, all things being equal it reduces the forecast RAB which leads to a lower return on capital (and therefore revenue) in future periods.
- AusNet Services' forecast (revenue-capped) metering services per customer in 2025–26 are higher than those in 2020 whereas for each of the other Victorian distributors, they are lower.

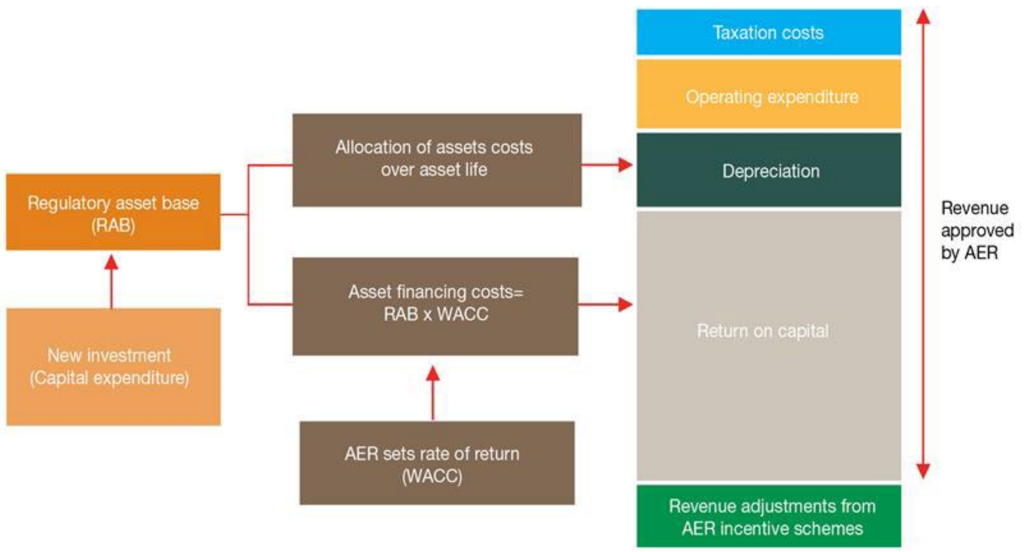
In our price path calculation, for the 2020 base year revenue, we use the total allowed revenue (TAR) and adjust for consumer price index (CPI). AusNet Services' 2020 TAR includes a B factor reduction to true-up recent over-recovery of revenue. This B factor reduction for AusNet Services is the largest among the Victorian distributors. Similarly, Jemena and Powercor also each include a (smaller) B factor reduction to 2020 revenue while conversely CitiPower and United Energy each include a B factor addition. AusNet Services' relatively lower base (2020) revenue therefore accentuates the bill increase arising from our decision for the 2021–26 regulatory control period.

2 Key components of our final decision on revenue

The total revenue AusNet Services proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2021–26 regulatory control period. AusNet Services' proposal, and our assessment of it under the National Electricity Law (NEL) and NER, are based on a 'building block' approach to determine a total revenue allowance which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes (section 2.7).

Figure 5 The building block model to forecast network revenue



Source: AER, *State of the Energy Market*, December 2018, p.138.

We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, and is consistent with the National Electricity Objective (NEO). Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our final decision on AusNet Services' distribution revenues for the 2021–26 regulatory control period is set out in Table 2

Table 2 AER's final decision on AusNet Services' revenues for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Return on capital	225.1	223.9	222.7	218.7	212.8	1103.2
Regulatory depreciation	184.9	163.2	163.0	168.5	170.8	850.4
Operating expenditure	244.9	253.2	262.2	272.1	283.4	1315.8
Revenue adjustments	84.6	53.9	32.8	12.4	10.2	193.9
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	0.0
Annual revenue requirement (unsmoothed)	739.5	694.3	680.7	671.7	677.1	3463.3
Annual expected revenue (smoothed)	**690.8**	**692.4**	**694.1**	**695.7**	**697.4**	**3470.5**
X factor[d]	n/a[e]	1.73%	1.73%	1.73%	1.73%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), the capital expenditure sharing scheme (CESS) and the demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) AusNet Services is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision. The expected revenue for 2021–22 is equal to the approved total annual revenue for 2020 in real terms, or 2.0 per cent higher in nominal terms after taking into account the escalation by half year Consumer Price Index (CPI) to allow comparison of the revenue from 1 July 2021 onwards.

2.1 Regulatory asset base

The RAB is the value of assets used by AusNet Services to provide regulated distribution services. The value of the RAB substantially impacts AusNet Services' revenue requirement, and the price consumers ultimately pay. This makes it a key issue for many stakeholders. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on AusNet Services' revenue for 2021–26, we make a decision on AusNet Services' opening RAB as at 1 July 2021. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block.

Our final decision is to determine an opening RAB value of $4657.4 million ($ nominal) as at 1 July 2021 for AusNet Services. This amount is $1.0 million (or less than 0.1 per cent) higher than AusNet Services' revised proposed opening RAB of $4656.5 million ($ nominal) as at 1 July 2021.[17] While we largely accept the proposed methodology for calculating the opening RAB, in AusNet Services' roll forward model (RFM) we have amended inputs for the six month period of 1 January to 30 June 2021 (the six month 2021 period) for forecast depreciation, the nominal rate of return and equity raising costs.

To determine the opening RAB as at 1 July 2021, we have rolled forward the RAB over the 2016–20 regulatory control period and a further roll forward for the six month 2021 period[18] to arrive at a closing RAB value at 30 June 2021 in accordance with our RFM. This roll forward includes an adjustment at the end of the 2016–20 regulatory control period to account for the difference between actual 2015 capex and the estimate approved in the 2016–20 determination.[19] All other end of period adjustments are applied at 30 June 2021 to establish the opening RAB value at 1 July 2021.[20]

Table 3 sets out the roll forward of the RAB to the end of the 2016–21 period.

Table 3 AER's final decision on AusNet Services' RAB for 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening RAB	3442.1	3610.5	3809.4	4067.6	4308.1	4467.4
Capital expenditure[c]	298.7	332.6	367.3	349.0	348.5	200.1
Inflation indexation on opening RAB	52.0	36.9	73.7	84.5	68.6	54.5
Less: straight-line depreciation[d]	182.3	170.6	182.8	193.0	208.2	99.3
Interim closing RAB	3610.5	3809.4	4067.6	4308.1	4517.0	4622.7
Difference between estimated and actual capex in 2015					–38.1	
Return on difference for 2015 capex					–11.6	

17 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal*, December 2020, pp. 100–101.

18 The additional roll forward for six months is due to the decision by the Victorian government to change the timing of the annual Victorian electricity network price changes to financial year basis from calendar year basis. This change means the current regulatory control period of 2016–20 is extended by six months and the next regulatory control period will commence on 1 July 2021.

19 The adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2016–20 determination.

20 These end of period adjustments are applied at the end of the final year of the roll forward period which in this case is 30 June 2021. For AusNet Services this includes adjustment for capitalised leases, and reallocation for accelerated depreciation purposes associated with SCADA/Network and rapid earth fault current limiter (REFCL) assets.

	2016	2017	2018	2019	2020[a]	2021[b]
Closing RAB as at 31 December 2020					4467.4	
Final year asset adjustment[e]						34.8
Opening RAB as at 1 July 2021						**4657.4**

Source: AER analysis.

(a) Based on estimated capex provided by AusNet Services. We will true-up the RAB for actual capex at the next reset.

(b) The six month 2021 period of 1 January to 30 June 2021. Based on estimated capex provided by AusNet Services. We expect to update the RAB roll forward with a revised capex estimate in the final decision, and true-up the RAB for actual capex at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.

(d) Adjusted for actual CPI. Based on forecast capex.

(e) For RAB roll-in of capitalised property leases.

Note: Summation of entries may not equal totals due to rounding.

For this final decision, we determine a forecast closing RAB value at 30 June 2026 of $5288.1 million ($ nominal) for AusNet Services. This is $145.6 million (or 2.7 per cent) lower than AusNet Services' revised proposal of $5433.6 million ($ nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2021, and our final decisions on the expected inflation rate (attachment 3), forecast depreciation (attachment 4) and forecast capex (attachment 5).[21] Table 4 sets out our final decision on the forecast RAB values for AusNet Services over the 2021–26 regulatory control period.

Table 4 AER's final decision on AusNet Services' RAB for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26
Opening RAB	4657.4	4818.5	4992.5	5114.7	5202.4
Capital expenditure[a]	346.0	337.2	285.2	256.2	256.4
Inflation indexation on opening RAB	93.1	96.3	99.8	102.3	104.0
Less: straight-line depreciation	278.0	259.6	262.8	270.7	274.8
Closing RAB	**4818.5**	**4992.5**	**5114.7**	**5202.4**	**5288.1**

Source: AER analysis.

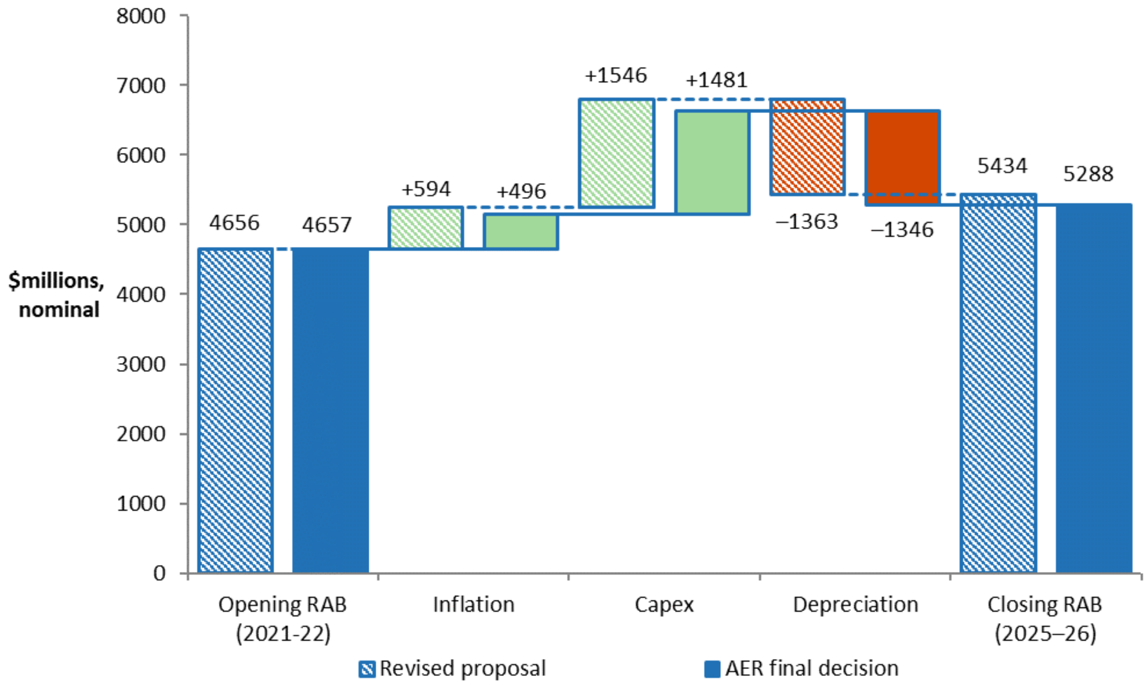
21 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2021–26 regulatory control period (section 2.2 of the Overview).

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling.

We are satisfied that the use of a forecast depreciation approach in combination with the application of the CESS and our other ex post capex measures are consistent with the capex incentive objective.[22] Further, this approach is consistent with our draft decision, AusNet Services' revised proposal and our *Framework and approach*.[23]

Figure 6 shows the key drivers of the change in AusNet Services' RAB over the 2021–26 regulatory control period for this final decision. Overall, the closing RAB at the end of the 2021–26 regulatory control period is forecast to be 13.5 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 31.8 per cent, while expected inflation increases it by 10.6 per cent. Forecast depreciation, on the other hand, reduces the RAB by 28.9 per cent.

Figure 6 AusNet Services' actual, revised proposed and AER final decision RAB ($ nominal)



Source: AER analysis.

22 Our ex post capex measures are set out in the capex incentive guideline, AER, *Capital expenditure incentive guideline for electricity network service providers,* November 2013, pp. 13–19 and 20–21. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

23 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, Attachment 2 – Regulatory Asset Base*, September 2020, p. 20; AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal*, 3 December 2020, pp. 149–151; AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy – Regulatory control period commencing 1 January 2021,* January 2019, pp. 83–85.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Further detail on our final decision regarding the RAB is set out in attachment 2.

2.2 Rate of return and value of imputation credits

The return each business is to receive on its RAB (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB. We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt.

The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors. An accurate estimate of the rate of return is necessary to promote efficient prices in the long-term interests of consumers.

We are required by the NEL to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[24]

The Victorian Government moved the Victorian distributors from a calendar year regulatory control period to a financial year regulatory control period. [25] This entailed a six month extension to the current regulatory control period (2016–20) through to June 2021, then a five year regulatory control period starting on 1 July 2021.[26] Our 2018 Instrument was applied from 1 January 2021—that is, to the six month extension period as well as the following five financial years which form the 2021–26 regulatory control period. Some amendments to the 2018 Instrument were needed to accommodate the additional six month period. The Victorian government enabled these amendments through the NELA Act.[27] Therefore, we apply modified 2018 Instruments to both periods.[28] [29]

Application of a modified 2018 Instrument in this final decision estimates an allowed rate of return of 4.83 per cent (nominal vanilla) for the five year regulatory control

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24 NEL, Part 3, division 1B. AER, *Rate of return instrument*, December 2018, available at https://www.aer.gov.au/networks-pipelines/guidelinesschemes-models-reviews/rate-of-return-guideline-2018/final-decision

25 *National Energy Legislation Amendment Act 2020 (Vic)*. Available at: https://www.legislation.vic.gov.au/as-made/acts/national-energy-legislation-amendment-act-2020

26 The six month extension period was also labelled as the 'mini-year' when we consulted on the modifications to the 2018 Rate of Return Instrument.

27 *National Energy Legislation Amendment Act 2020*.

28 *National Energy Legislation Amendment Act 2020*.

29 For the six month extension period instrument see: AER, *Modified rate of return instrument for the Victorian electricity distribution networks during the extension period of 1 January 2021 to 30 June 2021*, 27 October 2020; For the instrument to apply to the 2021–26 regulatory control period, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

period commencing 1 July 2021. We note AusNet Services' proposal and revised proposal also applied these modifications to the 2018 Instrument.[30]

Our calculated rate of return (in Table 5) will apply to the first year of the 2021–26 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with a modified 2018 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year.

Table 5 AER's final decision on AusNet Services' rate of return (nominal)

	AER draft decision (2021–26)	AusNet Services' revised proposal (2021–26)	AER final decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	0.93%[a]	0.93%	1.46%[c]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.59%	4.59%	5.12%	Constant (%)
Return on debt (nominal pre–tax)	4.66%[b]	4.66%	4.64%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.63%	4.63%	4.83%	Updated annually for return on debt
Expected inflation	2.37%	2.37%	2.00%	Constant (%)

Source: AER analysis; AusNet Services, *Electricity distribution price review 2022-26, Revised regulatory proposal*, December 2020, pp. 124–125.

a,b Calculated using a placeholder averaging period.

c, Calculated using an averaging period of 18 January 2021 to 31 March 2021.

d Final decision return on debt is calculated using the proposed and accepted debt averaging period.

Our final decision is also to accept AusNet Services' proposed risk free rate averaging period[31] and debt averaging periods because they comply with conditions in a modified 2018 Instrument.[32] These were submitted with its initial regulatory proposal and we specify the debt averaging periods in confidential appendix A to attachment 3.

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30 AusNet Services, *Electricity Distribution Price Review 2022–26 Part III*, January 2020, pp. 212-214; AusNet Services, *Electricity distribution price review 2022–26, Revised regulatory proposal*, December 2020, pp. 124–125.

31 This is also known as the return on equity averaging period.

32 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).; see also AER, *Final decision, AusNet Services distribution determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, April 2021

Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

We note AusNet Services has proposed to use our approach to estimate equity raising costs.[33] We have updated our estimate for this regulatory control period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

Our final decision is to accept the method used in AusNet Services' revised proposal which uses an annual rate of 7.93 basis points per annum.[34] We have considered this annual rate and found our alternative benchmark estimate (8.00 basis points) is similar to AusNet Services' proposal.

Imputation credits

Our final decision is to apply a gamma of 0.585 as provided in a modified 2018 Instrument.[35] AusNet Services' revised proposal has adopted a value of 0.585.[36]

Inflation

We estimate an expected inflation of 2.0 per cent based on the approach adopted in our final position paper from our 2020 inflation review.[37] [38] AusNet Services supported the new approach to estimating expected inflation.[39]

True up for six month extension period

We applied placeholder averaging periods in our final decision for the six month extension period of 1 January 2021 to 30 June 2021.[40] This was because of the unanticipated delay in the passing of the NELA Act, and to facilitate our pricing process – the nominated (and accepted) averaging periods would not have finished in time to

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33 AusNet Services, *Electricity distribution price review 2021–26, Revised regulatory proposal*, December 2020, p. 126.

34 AusNet Electricity Services Pty Ltd, *Electricity distribution price review 2022–26, Revised regulatory proposal*, December 2020, p. 126; AusNet Electricity Services Pty Ltd, *AusNet Services - Revised Regulatory Proposal - PTRM Model (2022-26) – March 2021,* March 2021.

35 For the modified application of the 2018 instrument to the regulatory control period 2021–26,, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

36 AusNet Services, *Electricity distribution price review 2022-26, Revised regulatory proposal*, December 2020, p. 125.

37 AER, *Final position, Regulatory treatment of inflation*, December 2020.

38 See our latest version of the PTRM (version 5) released in April 2021; AER, *Final position, Regulatory treatment of inflation*, December 2020.

39 AusNet Services, *Electricity distribution price review 2022-26, Revised regulatory proposal*, December 2020, p. 127.

40 For example, see: AER, *Final decision AusNet Services six-month extension – variation decision*, October 2020, pp. 11–12.

allow practical estimation of the final rate of return (based on the accepted averaging periods).

We have calculated the updated rate of return for the extension period based on the nominated and accepted averaging periods, and in accordance with the modified six-month instrument and the Order in Council. We determine that the difference with the placeholder rate of return will be recovered through the C-factor as noted in our control mechanisms attachment.

2.3 Regulatory depreciation (return of capital)

Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). AusNet Services invests capital in large assets to provide electricity network services to its consumers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from consumers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance.

In deciding whether to approve the depreciation schedules submitted by AusNet Services, we make determinations on the indexation of the RAB and depreciation building blocks for AusNet Services' 2021–26 regulatory control period.[41] The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

Our final decision is to determine a regulatory depreciation amount of $850.4 million ($ nominal) for AusNet Services for the 2021–26 regulatory control period. This amount represents an increase of $81.6 million (or 10.6 per cent) to the $768.7 million ($ nominal) in AusNet Services' revised proposal.[42] It is $116.9 million (or 15.9 per cent) higher than the regulatory depreciation amount determined in the draft decision. This significant increase is driven by our review of lower expected inflation which resulted from our inflation review. This lower expected inflation (amongst other things) impacts the indexation component of the regulatory depreciation allowance.

In addition, in coming to this decision:

- We accept AusNet Services' revised proposed straight-line method to calculate the regulatory depreciation, which is consistent with our draft decision.
- We accept AusNet Services' revised proposal to continue with the year-by-year tracking approach to implement straight-line depreciation of existing assets, consistent with our draft decision.
- We accept AusNet Services' revised proposed asset classes and standard asset lives, which are consistent with our draft decision. We have amended the equity raising costs standard asset life consistent with our standard weighted average approach.

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41 NER, cll. 6.12.1, 6.4.3.

42 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26),* updated 24 March 2021.

- We accept AusNet Services revised proposed approach to calculate the accelerated depreciation of intelligent electronic devices (IEDs) relays and remote terminal units (RTUs) as it is consistent with our draft decision.
- We accept AusNet Services' revised proposed accelerated depreciation of approximately $3.9 million of other assets, in particular high bushfire risk assets which have been, or are forecast to be, replaced as part of the safety programs approved in the REFCL contingent project applications. This is consistent with our draft decision.
- As discussed in attachment 2, we accept AusNet Services' revised proposed end of period adjustment for capitalised property leases which adopted our draft decision approach. This included an update to the remaining life to 8.3 years from 8.4 years.[43]

The difference between our final decision and the revised proposal regulatory depreciation allowance is largely due to the following determinations on related parts of our decision:

- expected inflation over the 2021–26 regulatory control period (attachment 3)
- forecast capex (attachment 5) including its effect on the projected RAB over the 2021–26 regulatory control period.[44]

Further detail on our final decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

Capex refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. Capex is added to AusNet Services' RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Our final decision is to not accept AusNet Services' revised proposal of $1432.9 million (excluding disposals) and substitute our final decision forecast of $1384.1 million.

Although we largely accepted AusNet Services' initial proposal which was 19 per cent below its current regulatory period capex, we adjusted for several COVID-19 related factors and in its revised proposal AusNet Services included additional capex for connections and REFCL that was not a part of its initial proposal or our draft decision assessment.

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43 AusNet Services made this update to reflect actual 2019 capex, which became available after the draft decision.

44 Capex enters the RAB net of forecast disposals and capital contributions. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Our final decision on the RAB (Attachment 2) also reflects our updates to the WACC for the 2021–26 regulatory control period.

Instead of undertaking a top down assessment of AusNet Services' revised proposal, we have focussed on the incremental changes from our draft decision. We have made the following changes to AusNet Services' revised proposal to arrive at our final decision capex substitute:

- Connections – We do not consider AusNet Services' forecast decrease in customer contributions as a result of a change in the weighted average cost of capital (WACC) is reasonable. We have worked with AusNet Services and identified that AusNet Services may apply its connections policy in a way that is not materially affected by the WACC. This approach is more in line with the intent of the regulatory framework. We have also updated our draft decision COVID-19 adjustment for connections to account for updated Housing Industry Association (HIA) data.
- REFCL – We have largely accepted AusNet Services' updated REFCL forecast. However, we consider one ongoing REFCL compliance project at Ringwood North can reasonably be deferred to beyond the forecast period.
- Allocation of metering costs between SCS and ACS – We are not satisfied by AusNet Services' information provided in support of reversing our allocation of some metering costs from SCS to ACS. We have maintained our draft decision allocations. This change only affects the way costs are recovered rather than overall revenue.

2.5 Operating expenditure

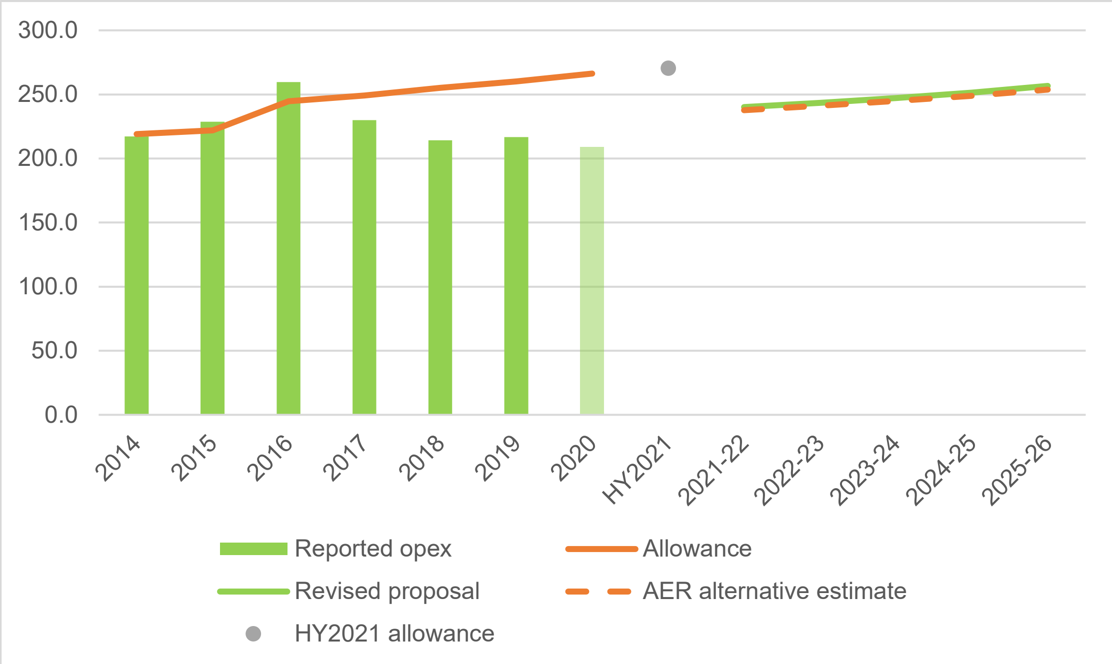
Opex is the forecast of operating, maintenance and other non-capital costs incurred in the provision of prescribed distribution standard control services. Forecast opex is one of the building blocks we use to determine AusNet Services' total regulated revenue requirement.

Our final decision is to accept AusNet Services' total opex forecast of $1238.7 million, including debt raising costs, for the 2021–26 regulatory control period. This is because our alternative estimate of $1226.8 million is not materially different than AusNet Services' updated revised proposal total opex forecast. Therefore we consider that AusNet Services' total opex forecast reasonably reflects the opex criteria.[45]

Figure 7 shows AusNet Services' opex forecast for the next five years, which is increasing by $109.2 million or 9.7 per cent relative to its actual (and estimated) opex in the current regulatory control period.

[45] NER, cl.6.5.6(c).

Figure 7 AusNet Services opex over time ($ million, 2020-21)



Source: AusNet Services, *2021–26 Regulatory proposal – Supporting document – Workbook 1 – Regulatory determination*, January 2020; AusNet Services, *2021–26 Regulatory proposal – Supporting document IR089 - insurance opex model,* 30 March 2021; AER, *Final Decision – AusNet Services distribution determination 2021–26 – Opex model,* April 2021; AER, *Draft Decision –AusNet Services distribution determination 2021–26 –Opex model,* September 2020; AER analysis.

Note: Operating expenditure for 2020 is an estimate.

We applied (as did AusNet Services) our top down base-step-trend approach to forecast increasing opex for the 2021–26 regulatory control period. This consists of:

- Starting with reported opex in 2018 as the opex base, which is lower than the forecast we set for the current regulatory control period, and we consider is reasonable as it is not materially inefficient.
- Escalating base opex to account for forecast changes in price growth, output growth and productivity over the next regulatory control period, which we consider is reasonable and consistent with our standard approach.
- Adding a number of step changes. The most significant step change proposed is for increasing insurance premium costs over the 2021–26 regulatory control period. Other increases include costs to meet new obligations such as those for REFCL testing and maintenance and five minute meter requirements. We have assessed these and consider they are prudent and efficient. These additions are a key driver for forecast opex being higher than historical levels.

We have set out the reasons for our final decision on opex in more detail in attachment 6. Our opex model, which calculates our alternative estimate of opex, is available on our website.

2.6 Corporate income tax

We determine an estimated cost of corporate income tax of zero for AusNet Services in the 2021–26 regulatory control period. This is consistent with our draft decision and AusNet Services' revised proposal.

We expect AusNet Services to incur a forecast tax loss over the 2021–26 regulatory control period.[46] We have determined that a $328.6 million in tax losses as at 30 June 2026 will be carried forward to the 2026–31 regulatory control period where it can be used to offset future tax liabilities. The forecast tax loss arises because of AusNet Services’ forecast tax expenses will exceed its revenue for tax assessment purposes over the 2021–26 regulatory control period. This is mostly due to the implementation of our findings from the 2018 *Review of the regulatory tax approach*, where the introduction of immediate expensing of capex and diminishing value method of tax depreciation have resulted in a significant increase of forecast tax depreciation.

For this final decision, we have:

- reduced the forecast immediately expensed capex for tax purposes from $769.6 million to $768.2 million ($2020–21)[47]
- accepted the revised proposed opening tax asset base (TAB) value as at 1 July 2021 of $3682.7 million[48]
- accepted AusNet Services' revised proposal on the standard tax asset lives for all of its asset classes, consistent with our draft decision
- updated AusNet Services' remaining tax asset lives as at 1 July 2021 to reflect our minor amendments to the opening TAB value
- accepted AusNet Services' revised proposal to change the tax treatment for large embedded generators by directly charging for the tax cost associated with their connections
- amended the tax treatment for gifted assets to be consistent with a recent ruling by the Full Federal Court of Australia[49] made after the draft decision.

Further detail on our final decision on corporate income tax is set out in attachment 7.

2.7 Revenue adjustments

Our final decision on AusNet Services' total revenue also includes a number of adjustments:

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46 A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to future regulatory control periods to offset future taxable income until the tax loss is fully exhausted.

47 All else equal, a lower immediately expensed capex amount will increase the cost of corporate income tax because it reduces the tax expense.

48 Subject to minor input updates for equity raising costs, weighted average cost of capital and depreciation for the 2021 half year. These changes are minor and do not have a material impact on the TAB (less than $0.01 million).

49 Federal Court of Australia, *Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169*, 21 October 2020.

- **EBSS** – AusNet Services accrued EBSS carryovers totalling $109.3 million ($2020–21) from the application of the EBSS in the 2016–20 regulatory control period. This is the same carryover amount AusNet Services included in its revised proposal. The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower forecast opex in subsequent periods. Attachment 8 sets out our final decision on AusNet Services' EBSS.
- **CESS** – AusNet Services has accrued rewards under the CESS we applied in the current 2016–20 regulatory control period to incentivise AusNet Services to undertake efficient capex throughout the period. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. In the 2016–20 period, AusNet Services out-performed our capex forecast, and our final decision is to approve a CESS revenue increment amount of $73.8 million ($2020–21). This amount reflects updates to CPI, WACC and actual capex.
- **Demand management innovation allowance mechanism (DMIAM)** —Table 6 sets out the DMIAM allowance for AusNet Services for the 2021–26 regulatory control period, based on the final PTRM for AusNet Services. The DMIAM aims to encourage distribution businesses to find investments that are lower cost alternatives to investing in network solutions.

Table 6 AER's final decision on the DMIAM ($ million, 2020-21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
DMIAM	0.76	0.71	0.69	0.68	0.67	3.52

Source: AER analysis.

Section 4 sets out our draft decision on the incentive schemes that apply to AusNet Services over the next regulatory control period.

3 AusNet Services' consumer Engagement

A significant development in the preparation of proposals for the Victorian Electricity Distribution 2021–26 regulatory control period, has been the improvement in consumer engagement approaches undertaken by the distributors. Stakeholders have commented favourably on the observed improvement in consumer engagement across all Victorian distributors.[50] As a result of this advancement, we developed a framework for assessing the Victorian distributor's consumer engagement activities, which we published in our draft decision.[51]

The framework sought to provide increased transparency around our assessment of consumer engagement outcomes and how this has influenced our decisions on expenditure forecasts. It was developed, based on our observations on the quality of engagement, to represent a range of considerations we thought clearly demonstrated if consumers had been genuinely engaged during development of proposals.[52] The framework, in its current form, represents a high threshold a distributor would need to meet – among other things – should it be seeking to submit a proposal that is 'capable of acceptance'. Used in conjunction with our technical analysis, the framework allowed us to place weight on the outcomes of the engagement activities undertaken by each distributor to assist in providing an overall assessment of expenditure proposals. In response to a number of submissions[53], this final decision also provides further clarity on the use of the framework in our decision making process. Noting that while we take the quality of consumer engagement, and the extent to which proposals are influenced by consumer preferences into account, it does not displace our technical assessment under the NER. The assessment of consumer engagement under the framework can however, inform the depth of technical assessment required.

Stakeholder submissions on our draft decision supported the framework[54], as a tool in our kit, along with the further development of our approach to consumer engagement.[55] We also recognise there may be other elements of engagement which

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50 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 6-42.; CCP17, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p.10.; Department of Environment, Land, Water and Planning, *Victorian Government submission on the electricity distribution price review 2021–26*, May 2020, p. 2;, EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 6.;

51 See Table 7: AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p. 45.

52 AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p. 44.

53 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 7.; VCO, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, p. 12; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12, 14.

54 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 2, 3-4.; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 8.; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12

55 Op cit.

are also worthy of inclusion as our assessment approach develops.[56] As a result, we plan to take any further development of the framework with full consultation with stakeholders, outside of the Victorian reset process. However, to maintain consistency of our assessment of the Victorian distributor's consumer engagement in this final decision, we have continued with the approach outlined in our draft decision.

3.1 Clarifying the role of consumer engagement

Some stakeholders have expressed concern that an assessment of high quality consumer engagement may lead to a decreased level of technical assessment. In particular, the Energy Users Association of Australia (EUAA) and the Victorian Community Organisation submissions suggested that successful participation in a New Reg process could lead to a network business getting a 'rails run', with less detailed regulatory scrutiny.[57]

The NER outlines that we must have regard to consumer concerns, and be satisfied that expenditure forecasts we approve reasonably reflect prudent and efficient costs. One of the factors that we must have regard to is the extent to which the capex and opex forecasts address consumer concerns identified throughout distributors' engagement with its customers.[58] However, this must be balanced against other capex and opex factors, including that we must have regard to distributors' actual and expected capex and opex in preceding regulatory periods[59], and whether the forecasts are consistent with any relevant incentive schemes.[60] In undertaking our reviews, we apply a number of bottom-up and top-down assessment techniques. Our technical analysis makes use of a range of measures, none of which are used deterministically in isolation. The quality of a distributor's consumer engagement informs the nature of our technical assessment but does not displace it.

AusNet Services' consumer engagement, through its participation in the New Reg trial, informed our assessment and gave us more confidence in placing sufficient weight on our top-down technical assessment.

The EUAA submissions, while complementary of the framework overall, outlined several areas of concern regarding our stated position on New Reg,[61] in how we

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56 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 6-42; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3-4.; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9.; CitiPower, Powercor and United Energy, Revised Regulatory Proposal – 2021–26 - December 2020, p. 26.; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 12-13.

57 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 1; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 14.

58 NER, cl. 6.5.7(e)(5A) and 6.5.6(e)(5A).

59 NER, cl. 6.5.7(e)(5) and 6.5.6(e)(5).

60 NER, cl. 6.5.7(e)(8) and 6.5.6(e)(8).

61 EUAA, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, June 2020, pp. 2,6.; EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 1.

applied the framework and regarding the manner in which commercial and industrial (C&I) customers were engaged in the process.[62][63]

The Customer Forum did engage with EUAA at a number of points in the process.[64] In seeking to understand the perspectives of all AusNet Services customers through direct engagement, input from customer advocates, as well as customer research, the Customer Forum also engaged with the views of C&I customers.[65] Nevertheless, we understand that the EUAA would have liked more and deeper engagement with the Customer Forum after the initial negotiating positions were published. This feedback is noted and is an issue that the AER will consider in the New Reg evaluation and in its thinking about how networks engage with different customer cohorts under our consumer engagement evaluation framework.[66] .

3.2 An assessment of consumer engagement

In our assessment of consumer engagement in the development of proposals for the 2021–26 regulatory control period, we recognise that each distributor has approached consumer engagement differently. AusNet Services innovated by participating in the New Reg trial, the goal of which was to ensure consumers' preferences drive energy network regulatory proposals and outcomes.[67] The main feature of the New Reg trial was the Customer Forum, which was engaged to represent the interests of AusNet Services' customers in negotiating selected aspects of AusNet Services' regulatory proposal.[68] In coming to our draft decision, we found that negotiations with its Customer Forum led to significant positive outcomes for consumers. This resulted in a draft decision, which after our technical assessment, was to accept AusNet Services' expenditure forecasts subject to updates and some adjustments due to changed economic conditions.[69]

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62 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 1

63 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 6.

64 While the Customer Forum did not separately meet with the EUAA after AusNet Services released its draft proposal, the Customer Forum met with the EUAA to understand the issues facing large energy users and again, (with the Major Energy Users) to test their initial negotiating positions prior to this. The Customer Forum also tested their initial and final negotiating positions with AusNet Services' Customer Consultative Committee of which the EUAA was a member. Further, the EUAA also attended 5 deep workshops after the draft determination with AusNet and the Customer Forum as well as making a detailed submission on the draft regulatory proposal and the Customer Forum's interim engagement report.

65 The Customer Forum met with 36 business customers, including the direct meetings with Exxon Mobil Longford, Australian Sustainable Hardwood, a dairy processor, a cheese factory, and Energy Australia. Air Liquide, Alcoa, and Bluescope Steel attended deep dives with the Customer Forum present. The Customer Forum also met with the Victorian Employers' Chamber of Commerce and Industry, Business Council of Australia, Energy Consumers Australia, The Benalla Business Network, The Master Builders Association. The Customer Forum also considered the results of customer research and surveys including a 'business customer survey' ref: (Customer Forum, Final Engagement Report, Jan 2020, p. 79) stakeholder interviews that canvased large business and advocate views (ref: Stephanie Judd, Customer Research and Insights Advisor, AusNet Services, *Understanding The Electricity Related Needs And Wants Of Customers: A Stakeholder Perspectives (Full Paper),* 2018).

66 AusNet Services, *Early Engagement Plan EDPR 2021–25 Customer Forum*, 2017, pp. 8-9.

67 AER, ECA, ENA, *New Reg: Towards Consumer-Centric Energy Network Regulation Approach Paper*, March 2018.

68 AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p. 3.

69 AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p. 3.

As previously indicated, we have applied our framework, as a form of benchmarking for all engagement approaches, to the assessment of AusNet Services' customer engagement in the development of its revised proposal. In doing so we recognise that the timeframe between our draft decision and submission of the revised proposal presented a challenge for distributors to address all elements of the framework.

In response to the draft decision and in preparation of its revised regulatory proposal, AusNet Services recommenced engagement with its stakeholder groups, including: re-engaging the Customer Forum, conducting a stakeholder forum, and meetings with its Customer Consultative Committee. Once the revised regulatory proposal had been developed, briefings were offered to interested stakeholders.[70] AusNet Services stated that the purpose of the engagement was to brief stakeholders on the draft decision and seek feedback across a broad range of issues being considered for the revised regulatory proposal.[71]

AusNet Services' engagement sought feedback from a diverse group of stakeholders. The topics of discussion delved deeply into the effects of our draft decision on AusNet Services' ability to deliver the expenditure program it developed in conjunction with the Customer Forum.[72] In response to our draft decision, the Customer Forum produced a memorandum which detailed the range of engagement and other activities it participated in following the draft determination. The memo also notes the adjustments we made in our draft decision, but reaffirmed the Customer Forum's support for the positions it took in its final engagement report[73].[74] As a result, selected expenditure items we questioned in our draft decision, such as the ICT Cloud step change, were re-proposed in the revised proposal.[75]

We consider that AusNet Services was genuine in seeking feedback, and reflected stakeholder's interests in its revised proposal.[76] EUAA noted how well AusNet Services engaged with it and other commercial and industrial customers in the preparation of its revised proposal.[77] The Consumer Challenge Panel, sub-panel 17 (CCP17) submission considered that despite the limited time available, AusNet Services "has effectively informed key stakeholders of the changes incorporated in its revised regulatory proposal, and has provided some opportunity for feedback".[78] Importantly, we can see references throughout AusNet Services' revised regulatory proposal incorporating this stakeholder input. The CCP17 also "observed or saw documentation of instances where stakeholder feedback influenced the final proposal, i.e. development of forecast customer numbers, ICT Cloud Step Change, and reallocation

70 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 34.

71 AusNet Services, *Revised Regulatory Proposal, 2021–26,* December 2020, p.15.

72 In relation to the 'Breadth and depth' element of the framework; AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p.45.

73 AusNet Services' Customer Forum, Customer forum final engagement report, January 2020.

74 AusNet Services, *Revised Regulatory Proposal, 2021–26,* December 2020, *Appendix #A, Customer Forum Memo,* December 2020, pp.1-3.

75 AusNet Services, *Revised Regulatory Proposal, 2021–26,* December 2020, p.15.

76 This assessment is in relation to the 'Clearly evidenced impact' element in our framework; ; AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview - September 2020*, p.45.

77 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p .8.

78 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 36.

of metering costs”.[79] The CCP17 submission also reinforced the need for “a comprehensive Consumer and Stakeholder Engagement Plan spanning the full timeline of the regulatory reset process”.[80]

In our assessment of the ‘proof point’, we found that from a top-down perspective, AusNet Services’ revised total forecast capex appears to be reasonable, subject to adjustments for COVID-19. However, in its revised regulatory proposal, AusNet Services included revised forecast capex changes beyond the scope of the updates we requested in our draft decision, including significant changes to REFCLs and connections. The additional forecast capex sought for these projects was $67.3 million[81], and was not assessed in our draft decision against the capex criteria. As a result, in this decision we have maintained our top-down assessment made in the draft decision but also conducted a bottom-up assessment of the additional capex.

The decision to conduct a bottom-up assessment of the additional forecast capex is supported by submissions we received from stakeholders including Energy Consumers Australia (ECA) who considered there should be no additional capex without a review of the entire capex program.[82] ECA also recommended that we undertake a careful review of the Kalkallo costs,[83] and the CCP17 considered we should conduct an in-depth analysis of the forecast capex increases.[84]

We found that overall, AusNet Services’ customer engagement was well received, with stakeholder preferences being reflected in the revised regulatory proposal. The distributor demonstrated breadth by engaging with a range of stakeholders and went into depth on the forecast expenditure affected by our draft decision. Despite the challenges presented by the limited time frame between the draft decision and submission of the revised regulatory proposal, AusNet Services’ customer engagement met many of the proof points we set out in the framework. Further, we consider that AusNet Services’ participation in the New Reg trial was at the collaborate end of consumer engagement on the IAP2 spectrum.[85]

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79 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 36.

80 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 36.

81 AusNet Services included an additional $15.5 million for additional REFCL compliance associated costs and $51.8 million for a decrease in capital contributions that were not assessed as part of our draft decision.

82 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, Spencer & Co, *Report to ECA – a review of Victorian Electricity Distributors’ revised proposals 2021–26*, January 2021, p.19

83 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, Spencer & Co, *Report to ECA – a review of Victorian Electricity Distributors’ revised proposals 2021–26*, January 2021, p.11

84 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp.88-89.

85 https://iap2.org.au/wpcontent/uploads/2020/01/2018_IAP2_Spectrum.pdf

4 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination we've discussed in section 2, to encourage AusNet Services to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

The incentive schemes that might apply to an electricity distribution network as part of our decision are:

- the EBSS
- the CESS
- the service target performance incentive scheme (STPIS)
- the Customer Service Incentive Scheme (CSIS)
- the demand management incentive scheme (DMIS) and allowance (DMIAM)
- the f-factor scheme.

Once we make our decision on AusNet Services' revenue cap, it has an incentive to provide services at the lowest possible cost, because its returns are determined by its actual costs of providing services. Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. If networks reduce costs to below our forecast of efficient costs, the savings are shared with its consumers in future regulatory control periods through a lower opex allowance and a lower RAB.

We understand the strong concerns of stakeholders, that the CESS not only rewards efficiency gains but also over forecasting and deferral of capex. The current CESS guideline includes protections against material deferrals that have been triggered for some elements of Powercor's proposal.[86] AusNet Services included a deferral adjustment and we made no further adjustments. Protection against over forecasting of capex lies in the rigorous assessment of proposed capex. Our draft decision also noted that we will be conducting an incentive scheme review to examine these stakeholder concerns.

The DMIS and the DMIAM provide businesses an incentive to undertake efficient expenditure on non-network options relating to demand management research and development in demand management projects that have the potential to reduce long-term network costs. All five Victorian distributors accepted our draft decision to apply the DMIS and DMIAM. We acknowledge that the Local Government Response expressed its concern that the full DMIAM allowance has been approved for Jemena,

[86] AER, *Final Decision, Powercor Distribution Determination 2021–26, Attachment 9 Capital Expenditure Sharing Scheme*, September 2020.

CitiPower and Powercor, without justification or evidence of the types of activities that will be undertaken. [87] While we acknowledge this concern, we consider that the DMIAM research and development works have the potential to deliver long-term savings to consumers. The scheme has an in-built control framework to ensure that only those expenditures that meet the tests prescribed by the scheme will be approved. Any unspent DMIAM allowance will be returned to the consumers.

Our final decision is to apply the DMIS and the DMIAM to AusNet Services for the 2021–26 regulatory control period, without any modification. Our draft decision reasons form part of this final decision.

The STPIS balances a distributor's incentive to reduce expenditure with the need to maintain or improve service quality. Our final decision is to apply our national STPIS version 2.0 (November 2018) to AusNet Services for the 2021–26 regulatory control period. We will not apply the guaranteed service level component to AusNet Services as the existing jurisdictional arrangements will continue to apply. We will not apply the STPIS telephone answering target and incentive rate to AusNet Services in the next regulatory control period because the distributor has opted to apply our CSIS. However, AusNet Services should continue to report on the telephone answering parameter in the next regulatory control period.

To accompany the STPIS we have established the CSIS to try and capture how well the distributor is meeting customer preferences. The intention is for this to replace the 0.5 per cent of revenue tied to the telephone answering parameter under the STPIS. The CSIS was one of the outcomes of the engagement between AusNet Services and its Customer Forum. It was developed in the context of initiatives to encourage AusNet Services to continue to monitor and improve customer experience over the regulatory control period. AusNet Services has proposed to apply the CSIS in the next regulatory control period.

Our final decision is that each of the EBSS, CESS, STPIS, CSIS, DMIS and DMIAM should apply to AusNet Services for the 2021–26 regulatory control period.

Our final decision also includes how the f-factor scheme is applied to AusNet Services in the 2021–26 regulatory control period. The f-factor scheme is prescribed by the Victorian Government’s F-Factor Scheme Order 2016 to reduce the risk of fire starts by network assets.[88] The 2016 Order was amended by the F-factor Scheme Amendment Order 2020. We have made an f-factor scheme determination for AusNet Services under the F-Factor Scheme Order in respect of the 2021–26 regulatory control period, as detailed in attachment A of our draft decision. Our final decision is to make revenue adjustments for AusNet Services in accordance with the F-Factor Scheme Order by way of an annual adjustment through the "I-factor" component in the control mechanism, as specified in attachment 14 of the final decision.

We discuss our final decisions on each incentive scheme in attachments 8 to 12.

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87 LGR, prepared by Victorian Greenhouse Alliance, *Submission to the AER Victorian Electricity Distribution Price Review (EDPR) 2021–26, Local Government Response to the AER’s Draft Determination,* December 2020, p. 10.

88 *Victoria Government Gazette, G 51*, 22 December 2016, p. 3239.

5 Tariff structure statement

AusNet Services' 2021–26 proposal includes the second iteration of its tariff structure statement (TSS). Its current TSS applies from 1 January 2016 to 30 June 2021.[89]

The requirement on distributors to prepare a TSS arises from significant reforms to the rules governing distribution network pricing. These reforms aim to:

- help distributors provide better price signals to retailers to reflect what it costs to use the network
- manage future expectations for retailers, distributors and consumers by providing guidance on distributors' tariff strategy
- help the transition to more cost reflecting pricing.

Distributors do not directly charge end customers. Rather, distributors charge retailers for the network services provided to end customers. Retailers can then decide how best to pass on these price signals to end customers.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning and reassigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals.[90] It is accompanied by an indicative pricing schedule.[91] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network prices will change.

While an indicative pricing schedule must accompany the TSS, AusNet Services' tariffs for the entire 2021–26 regulatory control period are not set as part of this determination. Rather, tariffs for 2021–22 will be subject to a separate approval process that takes place in May 2021, after this final revenue determination in April 2021. Tariffs for the following four years will also be approved on an annual basis in May of each year.

Our final decision is to amend AusNet Services' TSS by:

- requiring stand-alone (grid scale) storage to face network price signals to guide their operation and contribute to the cost of operating and maintaining the electricity distribution networks they use
- specifying electric vehicle owners, once they are identified by the relevant network, will no longer have access to flat tariffs
- clarifying that retailers can request tariff reassignment from distributors to help optimise their portfolios while consumers retain control over their retail offer.

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[89] The regulatory control period (1 January 2016 to 31 December 2020) was extended by six months. Refer to the Executive Summary above for an overview of changes to the regulatory control period.

[90] NER, cl. 6.18.1A(a).

[91] NER, cl. 6.18.1A(e).

These amendments complement the changes AusNet Services already made to align with our draft decision. These changes include:

- reassigning residential consumers on legacy time of use, flexibility and demand tariffs to the new time of use or demand equivalent
- aligning with other distributors to allow solar customers to opt-out to a flat rate tariff but introducing a discount which increases by 1 per cent each year relative to the flat rate to incentivise take up of a cost reflective tariff
- providing greater clarity on how its tariff strategy aligned with DER integration and demand management initiatives.

On large customer tariff choice, our final decision is to allow AusNet Services to:

- not offer large user tariff choice at this time given the tight timelines between our draft decision and its revised proposal, as well as its intention to trial new large customer tariffs during the 2021–26 regulatory period.

On energy storage, we consider batteries should contribute to recovery of network costs and should face network price signals to guide their operation. This will retain consistency with other National Electricity Market jurisdictions given the absence of new rules or policy direction between our draft and final decisions. If the asset falls into a particular tariff class, it should be assigned to the same network tariffs as other customers in that tariff class, whether owned by a distributor, its affiliate or a third party. We have amended AusNet Services' TSS to reflect this position. To the extent batteries are used for network support they will remain exempt from network tariffs.

We note the AEMC has foreshadowed its intention to consult with stakeholders on efficiently integrating distributed energy resources and that charging arrangements may be considered more generally in the context of the Energy Security Board reforms. The Victorian distributors have also committed to trialling new tariffs for energy storage over the 2021–26 regulatory period.

Attachment 19 of this final decision provides detailed reasons for our decision on AusNet Services' TSS.

6 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how AusNet Services must set its prices. This includes the classification of services and the framework for AusNet Services' negotiated services.

6.1 Classification of services

Service classification determines the nature of economic regulation, if any, that is applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and which services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

In its revised proposal, AusNet Services accepted our draft decision on the classification of the services it provides.[92] Our final decision is to retain the classification structure and the services list as published in our draft decision for AusNet Services.[93] The list of classified services AusNet Services will provide for 2021–26 is set out in attachment 13 to this decision.

6.2 Negotiating framework and criteria

In our draft decision, we approved AusNet Services' proposed distribution negotiating framework for the 2021–26 regulatory control period.[94] We did not receive any objections or submissions on our draft decision. Our final decision is to approve AusNet Services' negotiating framework. The distribution negotiating framework that will apply to AusNet Services for the period of this determination is set out in attachment A. We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[95] Our final decision is to retain the NDSC that we published for AusNet Services in September 2020[96] for the 2021–26 regulatory control period. The NDSC gives effect to the negotiated distribution services principles.[97]

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92 AusNet Services, *Revised Regulatory Proposal - 2021–26 - December 2020*, Appendix A: Service Classification Proposal.

93 AER, *Draft decision AusNet Services distribution determination 2021 to 2026*, Attachment 12 Classification of services, September 2020. The services list can be found in Attachment A

94 AER, Draft Decision, *AusNet Services distribution determination 2021 to 2026*, September 2020, Attachment 17, p, 17-4

95 NER, cl. 6.12.1(16).

96 AER, Draft Decision, *AusNet Services distribution determination 2021 to 2026*, September 2020, Attachment 17, p, 17-4

97 NER, cl. 6.7.1.

6.3 Connection policy

In our draft decision, we did not approve AusNet Services' proposed connection policy for the 2021–26 regulatory control period. We modified AusNet Services' connection policy nominated in its original proposal, to the extent necessary to enable it to be approved in accordance with the rules' requirements.

AusNet Services accepted the majority of the changes we made to its initially proposed connection policy. However, it did not accept the threshold level for what size a new connections needs to be to contribute the upstream cost in addition to the network extension cost set in the draft decision. AusNet Services also proposed:

- a new change to its original proposal to include the tax liability to the capital contribution for large embedded generator connections
- to classify large embedded generator connections as alternate control service.

We do not agree to:

- the proposed changes to the upstream charge threshold because is not consistent with our Connection Charge Guideline published under the NER
- the change in classification for connection of large embedded generator because this is inconsistent with the Framework and Approach.

We accept AusNet Services' proposed change to include tax liability to the capital contribution for large embedded generator connections, since such change has been substantially consulted on with the relevant stakeholders. We agree that such change will reduce the level of cross-subsidy by load consuming network users to large embedded generators.

The approved connection policy for AusNet Services' 2021–26 regulatory control period is appended to attachment 18 of our final decision.

7 The National Electricity Law and Rules

The NEL and NER provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the NEO:[98]

> "…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."

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[99] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long-term interests of consumers.[100] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[101]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that is likely to contribute to the achievement of the NEO to the greatest degree.[102]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[103] These are set out in Appendix A and the relevant attachments. In coming to a decision that contribute to the achievement of the NEO, we have considered interrelationships of the constituent components of our final decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7).

98 NEL, s. 7.

99 NEL, section 16(1)(a).

100 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

101 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

102 NEL, s. 16(1)(d).

103 NER, 6.12.1.

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[104] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[105]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long-term interests of consumers.[106] A particular economically efficient outcome may nevertheless not be in the long-term interests of consumers, depending on how prices are structured and risks allocated within the market.[107] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree than others would. For example, we consider that:

- the long-term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[108]
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where consumers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[109]

[104] Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

[105] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

[106] *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].

[107] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

[108] NEL, s. 7A(7).

[109] NEL, s. 7A(6).

A Constituent decisions

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services set out in Attachment 13 will apply to AusNet Services for the 2021–26 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in AusNet Services building block proposal. Our final decision on AusNet Services' annual revenue requirement for each year of the 2021–26 regulatory control period is set out in Attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve AusNet Services' proposal that the regulatory control period will commence on 1 July 2021. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve AusNet Services' proposal that the length of the regulatory control period will be five years from 1 July 2021 to 30 June 2026.
The AER did not receive a request for an asset exemption under clause 6.4.B.1 (a) (1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is not to accept AusNet Services' proposed total forecast capital expenditure of $1432.9 million ($2020–21). Our final decision therefore includes a substitute estimate of AusNet Services' total forecast capex for the 2021–26 regulatory control period of $1384.1 million ($2020–21). The reasons for our final decision are set out in Attachment 5.
In accordance with clause 6.12.1(4)(i) of the NER and acting in accordance with clause 6.5.6(c) of the NER, the AER's final decision is to accept AusNet Services' proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $1238.7 million ($2020–21). The reasons for our final decision is set out in Attachment 6.
AusNet Services did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final decision is that the allowed rate of return for the 2021–22 regulatory year is 4.83 per cent (nominal vanilla) as set out in Attachment 3 of the final decision. The rate of return for the remaining regulatory years 2022–26 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the modified 2018 Rate of Return Instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs set out in the Order in Council made under section 16VE of the amended National Electricity (Victoria) Act 2005 (Vic), the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in Section 2.2 of this final decision Overview.

Constituent decision

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on AusNet Services' regulatory asset base as at 1 July 2021 in accordance with clause 6.5.1 and schedule 6.2 is $4657.4 million ($ nominal). This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NER, the AER's final decision on the estimate of AusNet Services’ corporate income tax is zero dollars for each regulatory year of the 2021–26 regulatory control period. This is discussed in Attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is to not approve the depreciation schedules submitted by AusNet Services. Our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in Attachment 4 of the final decision.

In accordance with clause 6.12.1(9) of the NER the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme (DMIS), demand management innovation allowance mechanism (DMIAM) or small scale incentive scheme (customer service incentive scheme) is to apply:

- We will apply version 2 of the EBSS to AusNet Services in the 2021–26 regulatory control period. This is discussed in Attachment 8 of the final decision.
- We will apply the CESS as set out in version 1 of the Capital Expenditure Incentives Guideline to AusNet Services in the 2021–26 regulatory control period. This is discussed in Attachment 9 of the final decision.
- We will apply our Service Target Performance Incentive Scheme (STPIS) to AusNet Services for the 2021–26 regulatory control period. This is discussed in Attachment 10 of the final decision.
- We will apply the DMIS and DMIAM to AusNet Services for the 2021–26 regulatory control period. This is discussed in the Overview of the final decision.
- We will apply the CSIS to AusNet Services for the 2021–26 regulatory control period. This is discussed in Attachment 12 of the final decision.

In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper, the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for AusNet Services for any given regulatory year is the total annual revenue calculated using the formulae in Attachment 14, which includes any adjustment required to move the Distribution Use of Service (DUoS) unders and overs account to zero. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply a revenue cap for type 5 and 6 metering (including smart metering) services and price caps for all other services. The revenue cap for AusNet Services’ type 5 and 6 metering (including smart metering) services for any given regulatory year is the total annual revenue for type 5 and 6 (including smart metering) services calculated using the formulae in Attachment

Constituent decision

14, which includes any adjustment required to move the metering unders and overs account to zero. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that AusNet Services must maintain a DUoS unders and overs account and a metering unders and overs account. It must provide information on these accounts to us in its annual pricing proposal. This is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(14) of the NER the AER's final decision is to apply the following nominated pass through events to AusNet Services for the 2021–26 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance coverage event
- Natural disaster event
- Insurer credit risk event
- Retailer insolvency event

These events have the definitions set out in Attachment 15 of the final decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is to not approve the tariff structure statement proposed by AusNet Services. This is discussed in Attachment 19 of the final decision.

In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by AusNet Services will apply for the 2021–26 regulatory control period. This is discussed in section 6.2 of this final decision overview and the negotiating framework is in Attachment A of this final decision.

In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria, published in our draft decision in September 2020, to AusNet Services for the 2021–26 regulatory control period. This is set out in section 6.2 of this final decision overview.

In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning and reassigning retail customers to tariff classes for AusNet Services is set out in Attachment 19 of the final decision.

In accordance with clause 6.12.1(18) of the NER, the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of AusNet Services' regulatory control period as at 1 July 2026. This is discussed in Attachment 2 of the final decision.

In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how AusNet Services is to report to the AER on its recovery of designated pricing proposal charges for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set this out in its annual pricing proposal. The method to report recovery of the charges and account for the under or over recovery of designated pricing proposal charges is discussed in Attachment 14 of the final decision.

Constituent decision

In accordance with clause 6.12.1(20) of the NER, the AER's final decision on how AusNet Services is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the 2021–26 regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges is to set this out in its annual pricing proposal. The method to report recovery of the charges and account for the under or over recovery of jurisdictional scheme amounts is discussed in Attachment 14 of the final decision.

In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to not approve the connection policy proposed by AusNet Services. Our final decision is to amend AusNet Services' proposed connection policy as set out in Attachment 18 of the final decision.

In accordance with section 16C of the National Electricity (Victoria) Act 2005, the NEL, the NER and the 'f-factor scheme order 2016',[110] the AER's final decision is to apply the f-factor incentive payments/penalties as a part of the 'I-factor' adjustment to the calculation of the total annual revenue requirement using the formulae in Attachment 14 of the final decision.

[110] http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf, Victoria Government Gazette, G 51 22 December 2016, p. 3239.

B List of submissions

We received public submissions from the following stakeholders on our draft decision and AusNet Services' revised proposal:

Stakeholder
AGL
Ausgrid
Consumer Challenge Panel 17
Electric Vehicle Council
EnergyAustralia
Energy Consumers Australia
Energy Users Association of Australia
Evie Networks
Firm Power
Groundline Engineering
Jemena Electricity Networks People’s Panel
Local Government Response, prepared by Victorian Greenhouse Alliances
Origin Energy
Red Energy and Lumo Energy
Victorian Community Organisations, prepared by Brotherhood of St Laurence, Renew, Victorian Council of Social Service

C Consumer engagement framework

The following table represented the framework outlined in our draft decision for considering consumer engagement.[111]

Element	Examples of how this could be assessed
Nature of engagement	• Consumers partner in forming the proposal rather than asked for feedback on distributor's proposal • Relevant skills and experience of the consumers, representatives, and advocates • Consumers provided with impartial support to engage with energy sector issues • Sincerity of engagement with consumers • Independence of consumers and their funding • Multiple channels used to engage with a range of consumers across a distributor's consumer base
Breadth and depth	• Clear identification of topics for engagement and how these will feed into the regulatory proposal • Consumers consulted on broad range of topics • Consumers able to influence topics for engagement • Consumers encouraged to test the assumptions and strategies underpinning the proposal • Consumers were able to access and resource independent research and engagement
Clearly evidenced impact	• Proposal clearly tied to expressed views of consumers • High level of business engagement, e.g. consumers given access to the distributor's CEO and/or board • Distributors responding to consumer views rather than just recording them • Impact of engagement can be clearly identified • Submissions on proposal show consumers feel the impact is consistent with their expectations

Proof point	• Reasonable opex and capex allowances proposed
	  ○ In line with, or lower than, historical expenditure
	  ○ In line with, or lower than, our top down analysis of appropriate expenditure
	  ○ If not in line with top down, can be explained through bottom up category analysis

[111] AER, *Draft decision, AusNet Services distribution determination 2021–26, Overview, September 2020*, Table 7 p. 46.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CPI	consumer price index
DER	distributed energy resources
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
EV	electric vehicle
NEL	National Electricity Law
NELA	National Energy Legislation Amendment Act 2020 *(Vic)*
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
repex	replacement expenditure
REFCL	rapid earth fault current limiter
RFM	roll forward model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 1
Annual revenue requirement

April 2021

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
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Melbourne Vic 3001

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Email: VIC2021-26@aer.gov.au

AER reference: 63599

Note

This attachment forms part of the Australian Energy Regulator (AER)'s final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiated services

Contents

1 Annual revenue requirement

This attachment sets out our final decision on AusNet Services' annual revenue requirement (ARR) for the provision of standard control services (SCS) over the 2021–26 regulatory control period. Specifically, it sets out our final decision on:

- the ARRs (unsmoothed), which are the sum of annual building block costs
- the total revenue requirement, which is the sum of the ARRs
- the annual expected revenues (smoothed)
- the X factors.

We determine AusNet Services' ARRs using a building block approach. We determine the X factors by smoothing the ARRs over the regulatory control period. The X factor is used in the CPI–X methodology to determine the annual expected revenue (smoothed).

1.1 Final decision

We determine a total ARR of $3463.3 million ($ nominal, unsmoothed) for AusNet Services for the 2021–26 regulatory control period, reflecting our final decision on the various building block costs. This is an increase of $103.0 million ($ nominal) or 3.1 per cent to AusNet Services' revised proposed total ARR of $3360.2 million.[1] The key reasons for the increase are the lower expected inflation rate that resulted from our inflation review which increases regulatory depreciation (Attachment 4) and also an increase in the rate of return (Attachment 3).

We determine the annual expected revenue (smoothed) and X factor for each regulatory year of the 2021–26 regulatory control period by smoothing the ARRs. Our final decision is to approve total expected revenues of $3470.5 million ($ nominal) for AusNet Services for the 2021–26 regulatory control period.

Table 1.1 shows our final decision on the ARR, annual expected revenue, and X factor for each year of the 2021–26 regulatory control period.

Table 1.1 AER's final decision on AusNet Services' revenues for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Return on capital	225.1	223.9	222.7	218.7	212.8	1103.2
Regulatory depreciation[a]	184.9	163.2	163.0	168.5	170.8	850.4
Operating expenditure[b]	244.9	253.2	262.2	272.1	283.4	1315.8

1 AusNet Services, *Revised Regulatory Proposal - PTRM Model (2022–26),* updated 24 March 2021.

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Revenue adjustments[c]	84.6	53.9	32.8	12.4	10.2	193.9
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	0.0
Annual revenue requirement (unsmoothed)	739.5	694.3	680.7	671.7	677.1	3463.3
Annual expected revenue (smoothed)	**690.8**	**692.4**	**694.1**	**695.7**	**697.4**	**3470.5**
X factor[d]	n/a[e]	1.73%	1.73%	1.73%	1.73%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from the efficiency benefit sharing scheme (EBSS), the capital expenditure sharing scheme (CESS) and the demand management innovation allowance mechanism (DMIAM). Includes a reduction of $0.7 million due to the deferral of Kalkallo project.

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) AusNet Services is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision. The expected revenue for 2021–22 is around 0.03 per cent lower than the approved total annual revenue for 2020 in real terms, or 2.0 per cent lower in nominal terms after taking into account the escalation by the half year Consumer Price Index (CPI) to allow comparison of the revenue from 1 July 2021 onwards.

1.2 AusNet Services' revised proposal

AusNet Services' revised proposal included total expected revenues (smoothed) of $3367.1 million ($ nominal) for the 2021–26 regulatory control period.

Table 1.2 sets out AusNet Services' revised proposed ARR, the annual expected revenue, and the X factor for each year of the 2021–26 regulatory control period.

Table 1.2 AusNet Services' revised proposed revenues for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Return on capital	215.6	215.1	215.3	212.5	208.1	1066.6
Regulatory depreciation[a]	168.5	146.8	146.4	152.1	155.0	768.7
Operating expenditure[b]	245.8	255.1	265.1	276.1	288.6	1330.8
Revenue adjustments[c]	84.7	54.1	32.9	12.3	10.2	194.1
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	0.0
Annual revenue requirement (unsmoothed)	714.5	671.1	659.6	653.1	661.9	3360.2
Annual expected revenue (smoothed)[d]	**665.6**	**669.5**	**673.4**	**677.3**	**681.3**	**3367.1**

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
X factor	n/a[d]	1.75%	1.75%	1.75%	1.75%	n/a

Source: AusNet Services, *Revised Regulatory Proposal - PTRM Model (2022–26),* updated 24 March 2021.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

(b) Includes debt raising costs.

(c) Includes revenue adjustments from EBSS, CESS and DMIAM. Includes a reduction of $0.7 million due to the deferral of Kalkallo project.

(d) AusNet Services is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision.

1.3 Assessment approach

We did not change our assessment approach for the ARR from our draft decision. Attachment 1 (section 1.3) of our draft decision details that approach.[2]

1.4 Reasons for final decision

For this final decision, we determine a total ARR of $3463.3 million ($ nominal, unsmoothed) for AusNet Services for the 2021–26 regulatory control period. This is an increase of $103.0 million ($ nominal) or 3.1 per cent to AusNet Services' revised proposed total ARR of $3360.2 million ($ nominal) for this period. This reflects the impact of our final decision on the various building block costs.

The changes we made to AusNet Services' revised proposed building blocks include (in nominal terms):

- an increase in the return on capital of $36.5 million or 3.4 per cent (Attachments 2, 3 and 5)
- an increase in the regulatory depreciation of $81.6 million or 10.6 per cent (Attachment 4)
- a reduction in the operating expenditure (opex) forecast of $14.9 million or 1.1 per cent (Attachment 6)[3]
- no change to the cost of corporate income tax of zero (Attachment 7).
- a reduction in the revenue adjustments of $0.2 million or 0.1 per cent (section 1.4.2 and Attachments 8, 9 and 11).[4]

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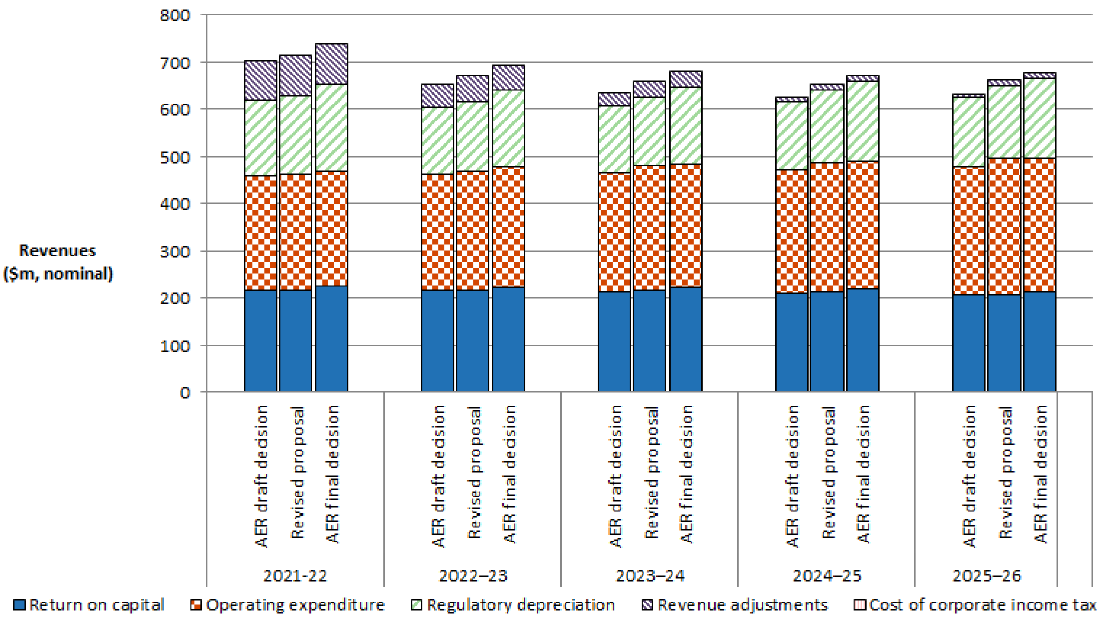
2 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, pp. 6–8.

3 While we accept AusNet Services' revised proposal opex in $2020–21 terms, the lower inflation in the final decision results in a nominal reduction.

4 We accept AusNet Services' proposed reduction of $0.7 million due to the deferral of Kalkallo project.

Figure 1.1 shows the building block components from our determination that make up the ARRs for AusNet Services and the corresponding components from its revised proposal and our draft decision.

Figure 1.1 AER's draft and final decisions and AusNet Services' revised proposed annual building block revenue requirement ($ million, nominal)



Source: AER analysis; AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal*, 03 December 2020.

Note: Revenue adjustments include EBSS, CESS and DMIAM amounts. Opex includes debt raising costs.

1.4.1 X factor and annual expected revenue

For this final decision, we determine an X factor for AusNet Services of 1.73 per cent per annum for the four years of the regulatory control period from 2022–23 to 2025–26.[5] The net present value (NPV) of the ARRs is $3038.7 million ($ nominal) as at 1 July 2021. Based on this NPV and applying the CPI–X framework we determine that the expected revenue (smoothed) for AusNet Services is $690.8 million in 2021–22 increasing to $697.4 million in 2025–26 ($ nominal). The resulting total expected revenue for AusNet Services is $3470.5 million for the 2021–26 regulatory control period.

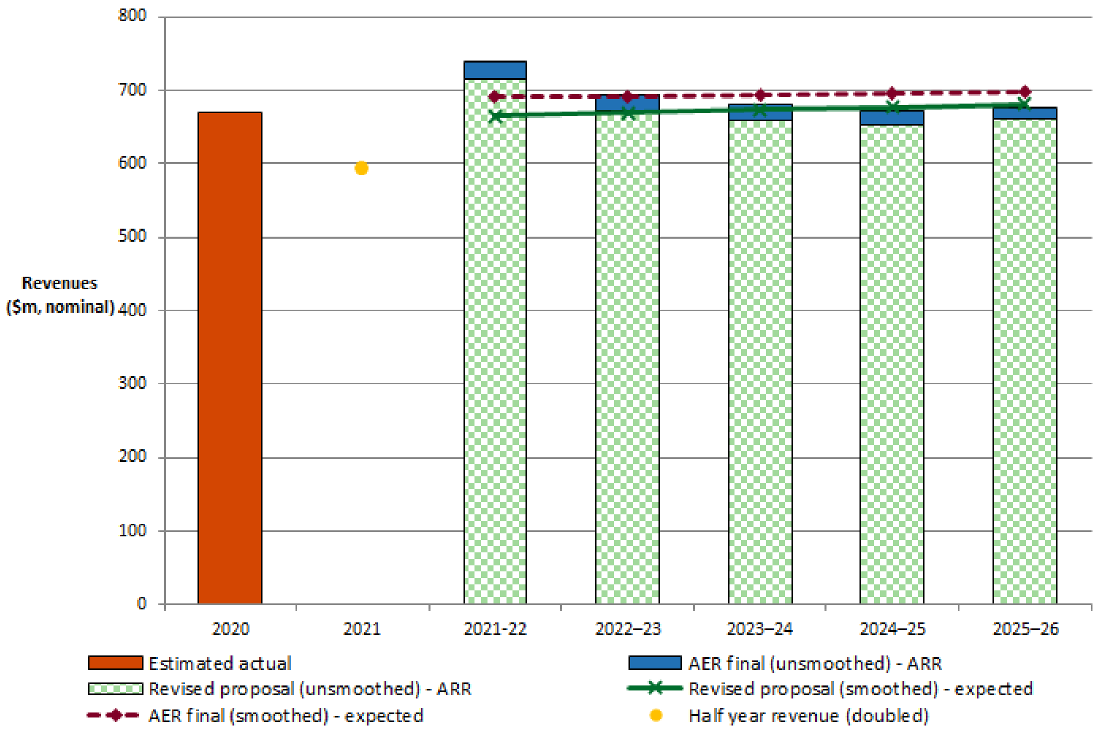
In our draft decision, we considered the 2020 total allowed revenue from AusNet Services' approved pricing proposal, escalated by the half year CPI, should form the 2020–21 starting revenue estimate of $677.4 million, as this was the latest

5 AusNet Services is not required to apply an X factor for 2021–22 because we set the 2021–22 expected revenue in this decision.

available estimate that we have approved.[6] AusNet Services adopted this estimate in its revised proposal.[7] This estimated 2020–21 starting revenue forms the base year to calculate the percentage change for the first year of the 2021–26 regulatory control period (P_0) for our final decision.

Figure 1.2 shows our final decision on AusNet Services' annual expected revenue (smoothed revenue) and the ARR (unsmoothed revenue) for the 2021–26 regulatory control period. For comparative purposes, the revenue for 2021 is shown as double the amount determined for the six month extension period between 1 January 2021 and 30 June 2021.[8] The relatively higher unsmoothed revenues in 2021–22 largely reflects our decision on accelerated depreciation that sees a number of old SCADA units and remote terminal units written off in that year.

Figure 1.2 AER's final decision on AusNet Services' revenue for the 2021–26 regulatory control period ($ million, nominal)



Source: AusNet Services, EDPR 2022–26 Revised Proposal – PTRM Model (2022–26), updated 24 March 2021; AER analysis.

Note: Revenue for 2021 is based on doubling the amount determined for the half year period between 1 January 2021 and 30 June 2021.

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6 AusNet Services, *Revised pricing proposal 2020*, 14 October 2019, p. 12.

7 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26),* updated 24 March 2021.

8 AER, *Model – Final decision six-month extension – AusNet Services – 2021 HY Post-Tax Revenue Model,* October 2020.

AusNet Services' revised proposal approach to revenue smoothing was to adopt the draft decision smoothed revenue in 2021–22 and then resmooth the X factor for the remaining 4 years of the regulatory control period.[9] This smoothed revenue profile resulted in a final year difference between smoothed and unsmoothed revenues of 4.9 per cent which is outside our preferred range of ± 3 per cent.[10]

Consistent with its initial proposal, AusNet Services' revised proposal submitted its concerns regarding our method of bill impact calculation which is based on revenue per unit of energy throughput. AusNet Services submitted that revenue per customer was a better way to calculate the bill impact and as such linked this metric to its revenue smoothing approach. In section 1.4.4 we discuss our reasons for maintaining our approach for calculating the bill impact for this final decision.

Subsequent to submitting its revised proposal, AusNet Services provided us with an updated post-tax revenue model (PTRM) which reflected the revised proposal PTRM but with updated forecast opex inputs.[11] The smoothed revenue profile for this updated PTRM comprised a 4.0 per cent real revenue decrease in the first year and real decreases of 1.8 per cent for years 2 to 5. For this smoothed revenue profile, the final year difference between smoothed and unsmoothed revenues was 2.9 per cent which is within our preferred range of ± 3 per cent. We consider this range is consistent with the requirements of the National Electricity Rules (NER) to minimise the difference between expected smoothed and unsmoothed revenues at the end of a regulatory control period.

Red Energy and Lumo Energy submitted that the revenues should remain stable to the extent possible in order to provide customers with stable tariffs in the long run.[12] We have considered the submission and taken into account the building block costs determined in this final decision when smoothing the expected revenues for AusNet Services over the 2021–26 regulatory control period. In doing so, we have set the expected revenue for the first regulatory year at $690.8 million ($ nominal) which is $48.7 million lower than the ARR for that year. We then apply an expected inflation rate of 2.00 per cent per annum and an X factor of 1.73 per cent per annum to determine the expected revenue in subsequent years.[13] We consider that our profile of X factors results in an expected revenue in the last year of the regulatory control period

9 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal*, December 2020, p. 41.

10 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26)*, updated 24 March 2021.

11 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26)*, updated 24 March 2021.

12 Red Energy and Lumo Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision*, 17 January 2021, p. 1

13 NER, cl. 6.5.9(a).

that is as close as reasonably possible to the ARR for that year.[14] This approach is consistent with our draft decision.[15]

Our final decision results in an average increase of 0.6 per cent per annum ($ nominal) in the expected (smoothed) revenue from 2020–21 to the end of the 2021–26 regulatory control period.[16] This consists of an initial increase of 2.0 per cent from 2020–21 to 2021–22, followed by average annual increases of 0.2 per cent during the remainder of the 2021–26 regulatory control period.[17] Our final decision also results in an increase of 1.4 per cent in real terms ($2020–21) to AusNet Services' total ARR relative to that in the 2016–20 regulatory control period. This is largely due to a higher regulatory depreciation and revenue adjustments in this final decision for the 2021–26 regulatory control period than that approved in the 2016–20 determination.

Figure 1.3 compares our final decision building blocks for AusNet Services' 2021–26 regulatory control period with AusNet Services' revised proposed revenue requirement for the same period, and the approved revenue for the 2016–20 regulatory control period.

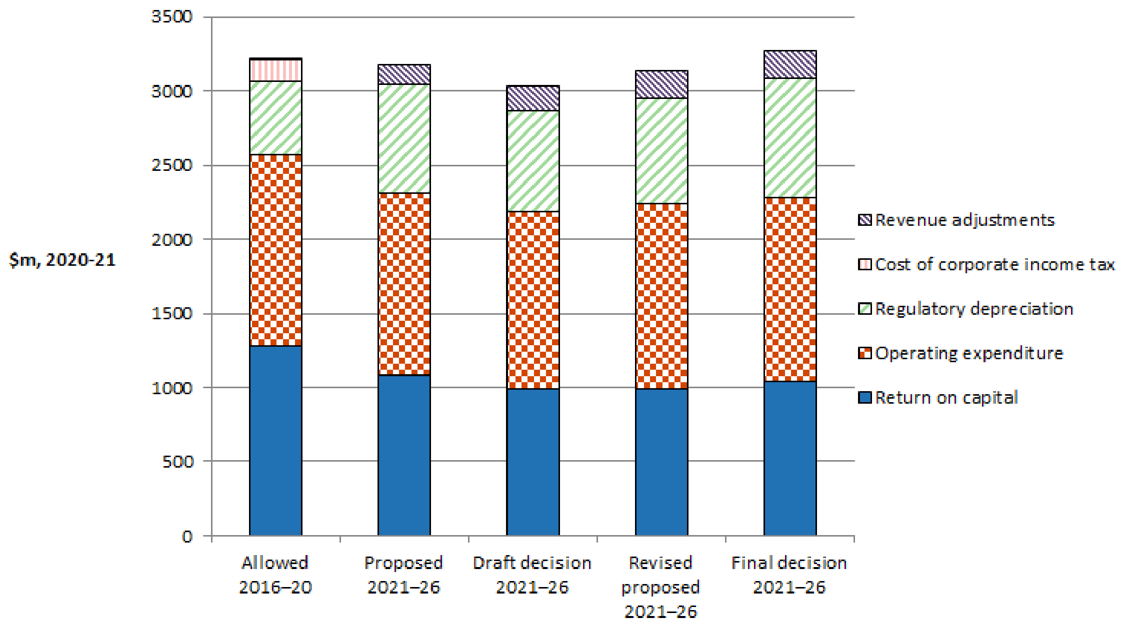
[14] NER, cl. 6.5.9(b)(2). We consider a divergence of up to 3.0 per cent between the expected revenue and ARR for the last year of the regulatory control period is appropriate, if this can achieve smoother price changes for users over the regulatory control period. In the present circumstances, based on the X factors we have determined for AusNet Services, this divergence is around 3.0 per cent.

[15] AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, pp. 9–12.

[16] In real 2020–21 dollar terms, our approved expected revenue for AusNet Services results in an average decrease of 1.4 per cent per annum over the 2021–26 regulatory control period.

[17] In real 2020–21 dollar terms, this consists an initial decrease of 0.03 per cent from 2020–21 to 2021–22, followed by annual average decreases of 1.73 per cent during the remainder of the 2021–26 regulatory control period.

Figure 1.3 Total revenue by building block components ($ million, 2020–21)



Source: AusNet Services, *Distribution Proposal PTRM model (2022–26)*, 31 January 2020; AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26)*, updated 24 March 2021; AER analysis.

1.4.2 Shared assets

Our final decision is not to apply a shared asset revenue adjustment to AusNet Services' total expected revenue for the 2021–26 regulatory control period.

In our draft decision, we did not apply a shared asset revenue adjustment to AusNet Services' revenues because we estimated that the unregulated revenues were less than one per cent of its expected revenues in each year of the 2021–26 regulatory control period. Therefore, the materiality threshold was not met in any year of the 2021–26 regulatory control period.[18] Using the same assessment approach as the draft decision, we consider that this materiality threshold is also not met in any year of the 2021–26 regulatory control period for this final decision, and we do not apply a shared asset revenue adjustment.

1.4.3 Indicative average distribution price impact

Our final decision on AusNet Services' expected revenues ultimately affects the prices customers pay for electricity. There are several steps required in translating our revenue decision into indicative distribution price impact.

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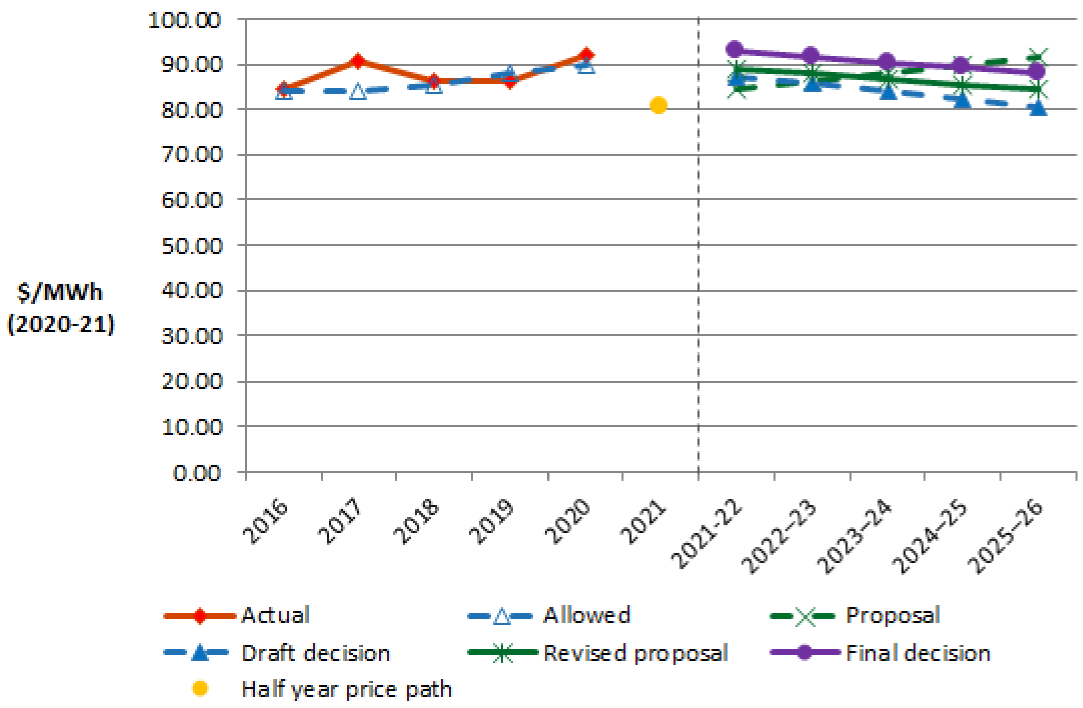
[18] AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, p. 13.

We regulate AusNet Services' SCS under a revenue cap form of control. This means our final decision on AusNet Services' expected revenues does not directly translate to price impacts. This is because AusNet Services' revenue is fixed under the revenue cap form of control, so changes in the consumption of electricity will affect the prices ultimately charged to customers. We are not required to establish the distribution prices for AusNet Services as part of this determination. However, we will assess AusNet Services' annual pricing proposals before the commencement of each regulatory year within the 2021–26 regulatory control period. In each assessment we will administer the pricing requirements set in this distribution determination.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our final determination on the expected revenues for AusNet Services over the 2021–26 regulatory control period. In this section, our estimates only relate to SCS (that is, the core electricity distribution charges), not alternative control services (such as metering charges). These indicative price impacts assume that actual energy consumption across the 2021–26 regulatory control period matches AusNet Services' forecast energy consumption, which we have adopted for this final decision. We also have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

Figure 1.4 shows AusNet Services' indicative average price path over the period 2016 to 2025–26 in real 2020–21 dollar terms based on the expected revenues established in our final decision compared to AusNet Services' revised proposed revenue requirement.

Figure 1.4 Indicative price path for AusNet Services ($/MWh, 2020–21)



Source: AER analysis.

Note: The price for 2021 is based on the revenue and energy throughput estimates for the half year period between 1 January 2021 and 30 June 2021.

We estimate that our final decision on AusNet Services' annual expected revenue will result in a decrease to average distribution charges by about 0.9 per cent per annum over the 2021–26 regulatory control period in real 2020–21 dollar terms.[19] This compares to the real average decrease of approximately 1.8 per cent per annum in AusNet Services' revised proposal for the 2021–26 regulatory control period.[20] These high-level estimates reflect the aggregate change across the entire network and do not reflect the particular tariff components for specific end users.

Table 1.3 compares the revenue and price impacts of AusNet Services' revised proposal and our final decision.

Table 1.3 Comparison of revenue and price impacts of AusNet Services' revised proposal and the AER's final decision ($ nominal)

	2020[b]	2021–22	2022–23	2023–24	2024–25	2025–26
AER final decision						
Revenue ($ million)	677.4	690.8	692.4	694.1	695.7	697.4
Price path ($/MWh)[a]	92.16	94.63	95.40	96.01	96.58	97.09
Revenue (change)		2.0%	0.2%	0.2%	0.2%	0.2%
Price path (change)		2.7%	0.8%	0.6%	0.6%	0.5%
AusNet Services revised proposal						
Revenue ($ million)	677.4	665.6	669.5	673.4	677.3	681.3
Price path ($/MWh)[a]	92.16	91.18	92.23	93.15	94.02	94.84
Revenue (change)		–1.7%	0.6%	0.6%	0.6%	0.6%
Price path (change)		–1.1%	1.2%	1.0%	0.9%	0.9%

Source: AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26)*, updated 24 March 2021; AER analysis.

(a) The price path is in nominal terms and is constructed by dividing nominal expected revenue for SCS by forecast energy consumption for each year of the regulatory control period.

(b) This is based on AusNet Services' 2020 approved pricing proposal, and has been indexed by the CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the price path from 1 July 2021 onwards.

19 In nominal terms we estimate average distribution charges to increase by 1.0 per cent per annum. This amount reflects an expected inflation rate of 2.00 per cent per annum as determined in this final decision.

20 In nominal terms AusNet Services' revised proposal would increase distribution charges by 0.6 per cent per annum. This amount reflects an expected inflation rate of 2.37 per cent per annum as proposed by AusNet Services in its revised proposal.

1.4.4 Expected impact of decision on electricity bills

The annual electricity bill for customers in AusNet Services' network reflects the combined costs of all the electricity supply chain components—wholesale energy generation, transmission, distribution, metering, and retail costs. This final decision primarily relates to the distribution charges for SCS, which represent approximately 34.0 per cent on average for residential customers' and 39.0 per cent on average for small business customers' annual electricity bills in AusNet Services' network area.[21]

We estimate the expected bill impact by varying the distribution charges in accordance with our final decision, while holding all other components—including the metering component—constant.[22] This approach isolates the effect of our final decision on the core distribution charges only. However, this does not imply that other components will remain unchanged across the regulatory control period.[23]

In its revised proposal, AusNet Services presented the price impacts using a revenue per customer measure consistent with its initial proposal. In our draft decision, we applied our standard approach which uses revenue per unit of energy.

We consider that our standard revenue per unit of energy approach is appropriate for businesses operating under a revenue cap. As noted in our draft decision, we have conducted our bill impact assessments in a consistent manner across regulatory decisions. We note our assessment (like AusNet Services') will ultimately differ from the actual impacts customer face for a number of reasons, not least because we only assess a proportion of the overall cost of electricity for a typical customer. In our draft decision, we noted that a measure of demand is needed to convert revenue to prices.[24] The derived unit of our revenue per unit of energy approach is in the form \$/MWh or c/kWh which is consistent with electricity usage tariffs that appear on bills and so is relatable for customers. Conversely, AusNet Services' suggested revenue per customer approach is more reflective of the fixed charges component of network tariffs which are driven by customer numbers rather than consumption levels.[25]

As noted in our draft decision, several stakeholders raised concerns with AusNet Services' revenue per customer measure for bill impact purposes.[26] These

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21 AusNet Services, *Workbook 7 – Bill Impacts 2022–26*, January 2020.

22 We also have not factored in any changes arising from incentive scheme amounts, cost pass throughs or unders/overs reconciliation that usually occur in the annual pricing process to come up with the total allowed revenue.

23 It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since AusNet Services operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2021–26 regulatory control period.

24 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, pp. 16–17.

25 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, p. 16.

26 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 1 – Annual revenue requirement*, September 2020, p. 17.

submissions supported a consistent and comparable approach across the networks. For this final decision, we consider AusNet Services has not provided sufficient new information in its revised proposal to support its revenue per customer approach. We are therefore satisfied that our revenue per unit of energy approach is appropriate for estimating bill impacts. Accordingly, we have maintained our revenue per unit of energy approach for AusNet Services' final decision and have applied this approach consistently across the Victorian distributors to provide reasonable comparisons.

Based on this approach, we expect that our final decision on the distribution component will increase the average annual residential electricity bill in 2025–26 by about $30 ($ nominal) or 1.8 per cent from the 2020 total bill level. Similarly, for an average small business customer, we expect that our final decision on the distribution component will increase the average annual residential electricity bill in 2025–26 by about $166 ($ nominal) or 2.1 per cent from the 2020 total bill level.

Our estimated impact is based on an average annual electricity usage of around 4,000 kWh per annum for residential households and 20,000 kWh for small businesses.[27] Therefore, customers with different usage will experience different changes in their bills. We also note that there are other factors, such as metering, wholesale and retail costs, which affect electricity bills.

Table 1.4 shows our estimated impact of our final decision and AusNet Services' revised proposal on the average annual electricity bills for residential and small business customers in its network over the 2021–26 regulatory control period.

Table 1.4 Estimated impact of AusNet Services' revised proposal and AER's final decision on annual electricity bills for the 2021–26 regulatory control period ($ nominal)

	2020	2021–22	2022–23	2023–24	2024–25	2025–26
AER final decision						
Residential annual bill	1666[a]	1681	1686	1690	1693	1696
Annual change[c]		15 (0.9%)	5 (0.3%)	4 (0.2%)	3 (0.2%)	3 (0.2%)
Small business annual bill	7945[b]	8028	8053	8074	8093	8110
Annual change[c]		83 (1.0%)	26 (0.3%)	21 (0.3%)	19 (0.2%)	17 (0.2%)
AusNet Services revised proposal						
Residential annual bill	1666[a]	1660	1667	1672	1677	1683
Annual change[c]		–6 (–0.4%)	6 (0.4%)	6 (0.3%)	5 (0.3%)	5 (0.3%)
Small business annual bill	7945[b]	7912	7947	7978	8007	8035

[27] Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision*, 18 November 2019, pp. 72−73.

	2020	2021–22	2022–23	2023–24	2024–25	2025–26
Annual change[c]		–33 (–0.4%)	35 (0.4%)	31 (0.4%)	29 (0.4%)	28 (0.3%)

Source: AER analysis; Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision*, 18 November 2019, p. 76.

(a) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 4,000 kWh for residential customers in Victoria. This is then indexed by the CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(b) Annual bill for 2020 is sourced from Essential Services Commission, *Victorian Default Offer to apply from 1 January 2020 – Final decision* and reflects the average consumption of 20,000 kWh for small business customers in Victoria. This is then indexed by the CPI for the half year period from 1 January 2021 to 30 June 2021 to allow comparison of the bill impact from 1 July 2021 onwards.

(c) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2020 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by AusNet Services. Actual bill impacts will vary depending on electricity consumption and tariff class.

Shortened forms

Shortened form	Extended form
$/MWh	dollars per megawatt hour
AER	Australian Energy Regulator
ARR	annual revenue requirement
CESS	capital expenditure sharing scheme
c/kWH	cents per kilowatt hour
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
EBSS	efficiency benefit sharing scheme
kWH	kilowatt hour
NER	National Electricity Rules
NPV	net present value
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
SCADA	supervisory control and data acquisition systems
SCS	standard control services

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 2
Regulatory asset base

April 2021

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

2 Regulatory asset base

Our distribution determination includes AusNet Services' opening regulatory asset base (RAB) value as at 1 July 2021 and the projected RAB value for the 2021–26 regulatory control period.[1] The value of the RAB substantially impacts AusNet Services' revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and return of capital (depreciation) components of the distribution determination.[2] This final decision sets out:

- the opening RAB as at 1 July 2021
- the forecast closing RAB as at 30 June 2026
- that depreciation based on forecast capital expenditure is to be used for establishing the RAB as at the commencement of the 2026–31 regulatory control period.[3]

2.1 Final decision

Opening RAB as at 1 July 2021

Our final decision is to determine an opening RAB value of $4657.4 million ($ nominal) as at 1 July 2021 for AusNet Services. This amount is $1.0 million (or less than 0.1 per cent) higher than AusNet Services' revised proposed opening RAB of $4656.5 million ($ nominal) as at 1 July 2021.[4] It reflects our update to the roll forward model (RFM) for our amended inputs for the six month period of 1 January to 30 June 2021 (the six month 2021 period) for depreciation, nominal rate of return and equity raising costs. This final decision is $52.4 million (or 1.1 per cent) lower than our draft decision value for AusNet Services' opening RAB of $4709.8 million ($ nominal).

To determine the opening RAB as at 1 July 2021, we have rolled forward the RAB over the 2016–20 regulatory control period and a further roll forward for the six month 2021 period[5] to arrive at a closing RAB value at 30 June 2021 in accordance with our RFM. This roll forward includes an adjustment at the end of the 2016–20 regulatory control period to account for the difference between actual 2015 capital expenditure (capex)

1 National Electricity Rules (NER), cl. 6.12.1(6).

2 The size of the RAB also impacts the benchmark debt raising cost allowance. However, this amount is usually relatively small and therefore not a significant determinant of revenues overall.

3 NER, cl. 6.12.1(18).

4 AusNet Services*, Revised Regulatory Proposal 2022–26*, December 2020, pp. 100–101.

5 The additional roll forward for six months is due to the decision by the Victorian government to change the timing of the annual Victorian electricity network price changes to financial year basis from calendar year basis. This change means the current regulatory control period of 2016–20 is extended by six months and the next regulatory control period will commence on 1 July 2021.

and the estimate approved in the 2016–20 determination.[6] All other end of period adjustments are applied at 30 June 2021 to establish the opening RAB value at 1 July 2021.[7]

In the draft decision, we reduced AusNet Services' proposed opening RAB as at 1 July 2021 by updating various inputs such as actual capex for 2019 and actual inflation for the six month 2021 period. Our draft decision also:[8]

- Amended the forecast equity raising costs, nominal rate of return and depreciation inputs for the six month 2021 period.
- Amended the RAB roll-in approach for capitalised property leases.
- Accepted AusNet Services' revision to the allocation of its IT system upgrade costs for the 2019–21 capex entries in the RFM.

We noted the roll forward of AusNet Services' RAB included estimated capex for 2020 and the six month 2021 period, because these actual values were not yet available.[9]

In its revised proposal, AusNet Services has adopted our draft decision changes.[10] In addition, it has revised its capex estimates for 2020 and for the six month 2021 period.[11] It has also made a minor amendment to the end of period adjustments for capitalised leases to reflect actual 2019 capex and updated the 2021 forecast depreciation to reflect the updated 2020 capex (discussed further below).

We accept AusNet Services' revision to its 2020 net capex estimate of $348.5 million ($ nominal) and six month 2021 period net capex estimate of $200.1 million ($ nominal).[12] The 2020 amount is $63.0 million lower and the six month 2021 period amount is $11.4 million higher compared to the amounts that we approved in our draft decision. In its revised proposal, AusNet Services submitted that the 2020 reduction is due to reduced planned outages during COVID-19 lockdown periods and the revised timing of the Kalkallo project. It submitted that the increase for the six month 2021 period is primarily due to an IT systems upgrade program relating to the metering

6 The adjustment will be positive (negative) if actual capex is higher (lower) than the estimate approved at the 2016–20 determination.

7 These end of period adjustments are applied at the end of the final year of the roll forward period which in this case is 30 June 2021. For AusNet Services this includes adjustment for capitalised leases, and reallocation for accelerated depreciation purposes associated with SCADA/Network and rapid earth fault current limiter (REFCL) assets.

8 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 2 – Regulatory Asset Base,* September 2020, pp. 4–5.

9 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 2 – Regulatory Asset Base*, September 2020, pp. 17–18.

10 AusNet Services*, Revised Regulatory Proposal 2022–26*, December 2020, p. 100.

11 AusNet Services*, Revised Regulatory Proposal 2022–26*, December 2020, pp. 103–104.

12 The 2020 amount remains an estimate while the actual for that period is being prepared. It includes a half-year WACC allowance to compensate for the six month period before capex is added to the RAB. The 2021 amount is also adjusted for WACC to reflect that it is added to the RAB at 30 June 2021.

requirements for 5-minute market settlement.[13] We note that the financial impact of any difference between actual and estimated capex for 2020 and the six month 2021 period will be accounted for at the next reset.

Our final decision also amends the forecast inputs for depreciation, nominal rate of return and equity raising costs for the six month 2021 period. This is discussed further below.

We also consider the extent to which our roll forward of the RAB to 1 July 2021 contributes to the achievement of the capital expenditure incentive objective.[14] As the Victorian distribution network service providers are moving from calendar regulatory years to financial regulatory years, the review period of past capex for this distribution determination will apply to the 2014–19 calendar regulatory years.[15]

AusNet Services' actual capex incurred for 2014 to 2019 is below the forecast allowance set at the previous distribution determinations. Therefore, the overspending requirement for an efficiency review of past capex has not been satisfied.[16] Given this, we consider the capex incurred in those years to be consistent with the capital expenditure criteria and can therefore be included in the RAB.[17]

For this final decision, we have included AusNet Services' estimated capex for 2020 and the six month 2021 period in the RAB roll forward to 1 July 2021. At the next reset, this capex will form part of the review period for whether past capex should be excluded for inefficiency reasons.[18] Our RAB roll forward applies the incentive framework approved in the previous distribution determination, which included the use of a forecast depreciation approach in combination with the application of the capital expenditure sharing scheme (CESS).[19] As such, we consider that the 2016–21 RAB roll forward contributes to an opening RAB (as at 1 July 2021) that includes capex that reflects prudent and efficient costs, in accordance with the capital expenditure criteria.[20]

Table 2.1 sets out our final decision on the roll forward of AusNet Services' RAB for the 2016–21 period.

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13 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 103.

14 NER, cll. 6.12.2(b) and 6.4A(a).

15 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 2 – Regulatory Asset Base*, September 2020, p. 17.

16 NER, cl. S6.2.2A(c).

17 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 5 – Capital expenditure*, September 2020, Appendix B; NER, cl. S6.2.1(f).

18 Here, 'inefficiency' of past capex refers to three specific assessments (labelled the overspending, margin and capitalisation requirements) detailed in NER, cl. S6.2.2A. The details of our ex post assessment approach for capex are set out in AER, *Capital expenditure incentive guideline*, November 2013, pp. 12–20.

19 AER, *Preliminary decision AusNet Services distribution determination - Attachment 2 - Regulatory asset base*, October 2015, p. 16.

20 NER, cll. 6.4A(a), 6.5.7(c) and 6.12.2(b).

Table 2.1 AER's final decision on AusNet Services' RAB for the 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening RAB	3442.1	3610.5	3809.4	4067.6	4308.1	4467.4
Capital expenditure[c]	298.7	332.6	367.3	349.0	348.5	200.1
Inflation indexation on opening RAB	52.0	36.9	73.7	84.5	68.6	54.5
Less: straight-line depreciation[d]	182.3	170.6	182.8	193.0	208.2	99.3
Interim closing RAB	3610.5	3809.4	4067.6	4308.1	4517.0	4622.7
Difference between estimated and actual capex in 2015					–38.1	
Return on difference for 2015 capex					–11.6	
Closing RAB as at 31 December 2020					4467.4	
Final year asset adjustment[e]						34.8
Opening RAB as at 1 July 2021						**4657.4**

Source: AER analysis.

(a) Based on estimated capex provided by AusNet Services. We will true-up the RAB for actual capex at the next reset.

(b) The six month period of 1 January to 30 June 2021. Based on estimated capex provided by AusNet Services. We will true-up the RAB for actual capex at the next reset.

(c) Net of disposals and capital contributions, and adjusted for actual consumer price index (CPI) and half-year weighted average cost of capital (WACC).

(d) Adjusted for actual CPI. Based on forecast capex.

(e) For RAB roll-in of capitalised property leases.

Note: Summation of entries may not equal totals due to rounding.

Capitalised leases

In the draft decision, we determined a value of $34.8 million ($ nominal) for AusNet Services' capitalised property leases to be included in the opening RAB as at 1 July 2021.[21] We accepted that the proposed leases should be capitalised but considered it was appropriate to roll-in the capitalised value of these assets into the RAB as an end of period adjustment. AusNet Services' approach in its initial proposal was to record the capitalised leases as capex mid-way through the regulatory control period which we did not consider appropriate as the asset classes were new and were not approved for that period.

[21] AER, *AusNet Services Draft decision: AusNet Services distribution determination 2021 to 2026 – Attachment 2 – Regulatory asset base,* 30 September 2020 pp. 16-19.
AusNet Services capitalised the value of these leases due to a change in the accounting reporting standard.

AusNet Services' revised proposal adopted our draft decision approach but updated the capitalised amount (reduced by less than $0.01 million) to reflect actual 2019 capex for these assets. It also reduced the remaining life to 8.3 years from 8.4 years. We have reviewed these amendments and consider them to be appropriate. We therefore accept the amended capitalised value and remaining life for this final decision.

Forecast inputs for the six month 2021 period

In its revised proposal, AusNet Services amended its RFM for the forecast depreciation input for the six month 2021 period to reflect its updates to 2020 capex. We consider that the straight-line depreciation used to roll forward the RAB should be consistent with the forecast straight-line depreciation component of the calculated revenue allowance for that year. This ensures no windfall gain/loss on depreciation. For this final decision, we have therefore amended the six month 2021 forecast depreciation values to reflect those in the six month post-tax revenue model (PTRM) and consistent with the draft decision RFM. AusNet Services agreed with this approach in response to our information request.[22]

In its revised proposal, AusNet Services did not update the equity raising costs or nominal rate of return inputs for the six month 2021 period in its RFM. Our revenue decision for AusNet Services' six month extension period contained placeholder values for both the return on equity and the return on debt.[23] Since the six month decision, we have updated these inputs in the six month PTRM with the return on debt and equity values reflecting the approved averaging periods.[24] This update in turn revised the benchmark equity raising costs for the six month PTRM. For this final decision for the 2021–26 regulatory control period, we have made corresponding equity raising costs and nominal rate of return updates to the RFM.[25] AusNet Services agreed with these updates in its response to our information request.[26]

Forecast closing RAB as at 30 June 2026

Once we have determined the opening RAB as at 1 July 2021, we roll forward that RAB by adding forecast capex and inflation, and reducing the RAB by depreciation to arrive at a forecast closing value for the RAB as at the end of the 2021–26 regulatory control period.[27]

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22 AusNet Services, *Information request #081*, February 2021.

23 AER, *Final decision AusNet Services six-month extension – variation decision*, October 2020, pp. 2-13, 2-14.

24 AER, *Model - Final decision six-month extension - AusNet Services - 2021 HY Post-Tax Revenue Model - March 2021*.
We will use the amended forecast six month revenue to calculate an appropriate revenue true-up for the 2021–26 regulatory control period.

25 We have adjusted the equity raising costs value in the RFM for a half year inflation, consistent with our approach in the draft decision RFM.

26 AusNet Services, *Information request #081*, February 2021.

27 NER, cl. S6.2.3.

For this final decision, we determine a forecast closing RAB value at 30 June 2026 of $5288.1 million ($ nominal) for AusNet Services. This is $145.6 million (or 2.7 per cent) lower than AusNet Services' revised proposal of $5433.6 million ($ nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2021, and our final decisions on the expected inflation rate (Attachment 3), forecast depreciation (Attachment 4) and forecast capex (Attachment 5).[28]

Table 2.2 sets out our final decision on the forecast RAB for AusNet Services over the 2021–26 regulatory control period.

Table 2.2 AER's final decision on AusNet Services' RAB for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26
Opening RAB	4657.4	4818.5	4992.5	5114.7	5202.4
Capital expenditure[a]	346.0	337.2	285.2	256.2	256.4
Inflation indexation on opening RAB	93.1	96.3	99.8	102.3	104.0
Less: straight-line depreciation	278.0	259.6	262.8	270.7	274.8
Closing RAB	**4818.5**	**4992.5**	**5114.7**	**5202.4**	**5288.1**

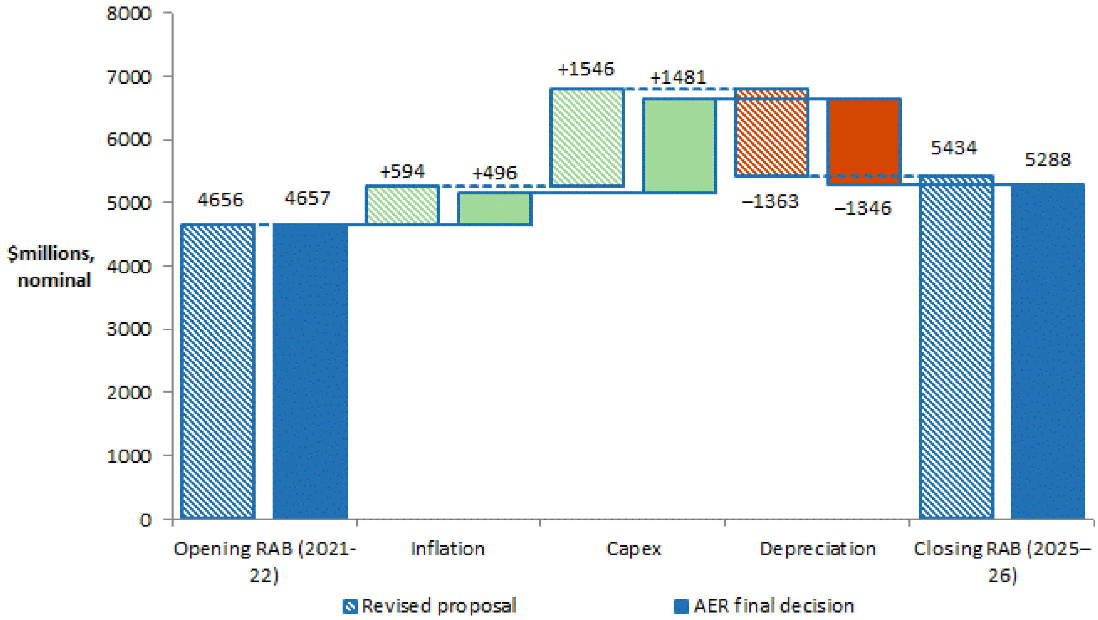
Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the PTRM, the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling.

Figure 2.1 shows the key drivers of the change in AusNet Services' RAB over the 2021–26 regulatory control period for this final decision. Overall, the closing RAB at the end of the 2021–26 regulatory control period is forecast to be 13.5 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 31.8 per cent, while expected inflation increases it by 10.6 per cent. Forecast depreciation, on the other hand, reduces the RAB by 28.9 per cent.

28 Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2021–26 regulatory control period (section 2.2 of the Overview).

Figure 2.1 Key drivers of changes in the RAB—AusNet Services' revised proposal compared with AER's final decision ($ million, nominal)



Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Forecast net capex is a significant driver of the increase in the RAB. In our final decision, we are not satisfied that AusNet Services' revised proposed forecast capex of $1432.9 million ($2020–21)[29] for the 2021–26 regulatory control period reasonably reflects the capex criteria. We have therefore amended AusNet Services' revised proposed capex for the 2021–26 regulatory control period to $1384.1 million ($2020–21). Refer to section 5.3 of Attachment 5 for the discussion on forecast capex.

Application of depreciation approach in RAB roll forward for next reset

When we roll forward AusNet Services' RAB for the 2021–26 regulatory control period at the next reset, we must adjust for depreciation. For this final decision, we determine that the depreciation approach to be applied to establish the RAB at the commencement of the 2026–31 regulatory control period will be based on the depreciation schedules (straight-line) using forecast capex at the asset class level approved for the 2021–26 regulatory control period.[30]

As discussed in Attachment 9, we will also apply the CESS to AusNet Services over the 2021–26 regulatory control period. We consider that the CESS will provide

29 This amount is net of capital contributions, disposals and equity raising costs, and excludes the half-year WACC adjustment.

30 NER, cl. 6.12.1(18).

sufficient incentives for AusNet Services to achieve capex efficiency gains over that period. We are satisfied that the use of a forecast depreciation approach in combination with the application of the CESS and our other ex post capex measures are sufficient to achieve the capex incentive objective.[31] Further, this approach is consistent with our draft decision, AusNet Services' initial proposal and our *Framework and approach*.[32]

2.2 Assessment approach

We did not change our assessment approach for the RAB from our draft decision. Attachment 2 (section 2.3) of our draft decision details that approach.

[31] Our ex post capex measures are set out in the capex incentive guideline, AER, *Capital expenditure incentive guideline for electricity network service providers,* November 2013, pp. 13–19 and 20–21. The guideline also sets out how all our capex incentive measures are consistent with the capex incentive objective.

[32] AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 2 – Regulatory Asset Base*, September 2020, p. 20; AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, pp. 149–151; AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy – Regulatory control period commencing 1 January 2021,* January 2019, pp. 83–85.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
CPI	consumer price index
NER	National Electricity Rules
PTRM	post-tax revenue model
RAB	regulatory asset base
RFM	roll forward model
RIN	regulatory information notice
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 3
Rate of return

April 2021

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

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AER reference: 63599

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

3 Rate of return

The return each business is to receive on its regulatory asset base (RAB), known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

We also make an estimate of expected inflation over the next five years, which sits alongside our nominal estimate of the rate of return. Together these determine the effective real return that will be provided to investors over the upcoming regulatory control period.

3.1 Final decision

We are required by the National Electricity Law (NEL) to apply a rate of return instrument—the current 2018 Rate of Return Instrument (2018 Instrument)—to estimate an allowed rate of return.[1]

The Victorian Government has moved the Victorian distributors from a calendar year regulatory control period to a financial year regulatory control period.[2] This entails a six month extension to the current regulatory control period (2016–20) through to June 2021, then a five year regulatory control period starting on 1 July 2021.[3] The 2018 Instrument will also need to be applied from 1 January 2021—that is, to the six month extension period as well as the following five financial years which form the 2021–26 regulatory control period.

However, the 2018 Instrument was developed on the basis of consecutive 12-month regulatory years, and does not contemplate or allow for an intervening six month

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1 NEL, Part 3, division 1B. AER, *Rate of return instrument*, December 2018, available at https://www.aer.gov.au/networks-pipelines/guidelinesschemes-models-reviews/rate-of-return-guideline-2018/final-decision.

2 *National Energy Legislation Amendment Act 2020*. Available at: https://www.legislation.vic.gov.au/as-made/acts/national-energy-legislation-amendment-act-2020.

3 The six month extension period was also labelled as the 'mini-year' when we consulted on the modifications to the 2018 Rate of Return Instrument.

extension period when moving from calendar years to financial years. This is important for the calculation of the trailing average portfolio return on debt under the Instrument. The 2018 Instrument also did not contemplate the nomination of averaging periods for a six month extension period.

The Victorian Government has enacted the change to a financial year regulatory control period through the *National Energy Legislation Amendment Act 2020* (Vic) (NELA Act). This also allowed application of a modified 2018 Instrument to the six month extension period and to the following financial year regulatory control period.[4] Therefore, we apply modified 2018 Instruments to both periods.[5] [6]

The content of a modified 2018 Instrument is substantively the same as the 2018 Instrument with changes to nomenclature, the averaging period criteria (for debt and risk free rate) and formulae for calculation of the trailing average return on debt.[7] We have consulted with stakeholders on the substantive elements of these changes.[8]

Application of a modified 2018 Instrument in this final decision estimates an allowed rate of return of 4.83 per cent (nominal vanilla) for the five year regulatory control period commencing 1 July 2021. We note AusNet Services' proposal and revised proposal also accepted the application of these modifications to the 2018 Instrument.[9]

Our calculated rate of return (in Table 3.1) will apply to the first year of the 2021–26 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with a modified 2018 Instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year.

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4 *National Energy Legislation Amendment Act 2020* (Vic).

5 *National Energy Legislation Amendment Act 2020* (Vic).

6 For the six month extension period instrument see: AER, *Modified rate of return instrument for the Victorian electricity distribution networks during the extension period of 1 January 2021 to 30 June 2021*, 27 October 2020; For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs).

7 See the Order in Council made on 27 October 2020 under section 16VE of the NEVA (Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs).

8 AER, *Application of the 2018 Rate of Return Instrument to the Victorian Electricity Distribution Networks from 1 January 2021*, 21 August 2020.

9 AusNet Services, *Electricity Distribution Price Review 2022–26 Part III*, January 2020, pp. 212-214; AusNet Services, *Electricity distribution price review 2022–26, Revised regulatory proposal*, December 2020, pp. 124-125.

Table 3.1 Final decision on AusNet Services' rate of return (nominal)

	AER draft decision (2021–26)	AusNet Services' revised proposal (2021–26)	AER final decision (2021–26)	Allowed return over regulatory control period
Nominal risk free rate	0.93%[a]	0.93%	1.46%[c]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.59%	4.59%	5.12%	Constant (%)
Return on debt (nominal pre–tax)	4.66%[b]	4.66%	4.64%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.63%	4.63%	4.83%	Updated annually for return on debt
Expected inflation	2.37%	2.37%	2.00%	Constant (%)

Source: AER analysis; AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 124–125.

[a,b] Calculated using a placeholder averaging period.

[c,] Calculated using an averaging period of 18 January 2021 to 31 March 2021.

[d] Final decision return on debt is calculated using the proposed and accepted debt averaging period.

Our final decision is also to:

- Accept AusNet Services' proposed risk free rate averaging period[10] and debt averaging periods because they comply with conditions in a modified 2018 Instrument.[11] These were submitted with its initial proposal and we specify the debt averaging periods in confidential appendix A. We publish the dates of the risk-free rate averaging period after it has expired.[12]
- Apply a gamma of 0.585 as provided in a modified 2018 Instrument.[13] AusNet Services' revised proposal has adopted a value of 0.585 which is consistent with this.[14]

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10 This is also known as the return on equity averaging period.

11 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).; see also AER, *Final decision, AusNet Services distribution determination 2021 to 2026, Attachment 3—Rate of return confidential appendix A: Equity and debt averaging periods*, April 2021.

12 AER, *Rate of return instrument explanatory statement,* December 2018, p. 140.

13 For the financial year regulatory control period instrument, see the Order in Council made on 27 October 2020 under section 16VE of the NEVA (*Attachment A - Modified rate of return instrument for the regulatory control period commencing on 1 July 2021 for the Victorian DNSPs*).

14 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p. 125.

Due to the timing of the Victorian legislation and the averaging periods proposed by the Victorian distributors, a true-up in the 2021–26 period is required for revenue during the six-month extension period (1 January 2021 to 30 June 2021).[15] We set out the final rate of return used for true-up in section 3.4 of this final decision.[16]

We note four of the Victorian electricity distributors (all except Jemena) submitted a November 2020 Frontier report as part of their revised proposals.[17] The report stated that, under the 2018 Instrument and the Reserve Bank of Australia's (RBA) current monetary policy, the allowed return on equity was lower than previous AER allowances and those from international regulators. Frontier considered that this led to negative profit and did not support an investment grade credit rating.

We note Frontier's observations. However, we consider that our working paper series (which forms part of our *Pathway to the 2022 Rate of Return Instrument*) is a better forum for considering the issues in the Frontier report. This is because the 2018 Instrument is binding on us and we cannot depart from it in this decision. AusNet Services itself proposed to apply the 2018 Instrument in its revised proposal.[18]

3.2 Expected inflation

We estimate an expected inflation of 2.00 per cent (see Table 3.2 for calculations) based on the approach adopted in our final position paper from our 2020 inflation review.[19] AusNet Services supported the new approach to estimating expected inflation.[20]

Table 3.2 Final decision on AusNet Services' forecast inflation (per cent)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	1.50	1.75	2.00	2.25	2.50	2.00

Source: AER analysis; *RBA Statement on Monetary policy*, February 2021.

15 This is due to the application of placeholder averaging periods to the six month extension period instead of the nominated and accepted averaging periods, if we consider it necessary or expedient for making the variation decision.
For example, see: AER, *Final decision AusNet Services six-month extension – variation decision*, October 2020, pp. 11–12.

16 The control mechanism chapter of our draft decision specifies how any adjustment amount will be included in regulated revenues. See AER, *Draft decision, AusNet Services Distribution Determination 2021 to 2026, Attachment 14 Control mechanisms*, September 2020.

17 Frontier, *The impact of artificially supressed [sic] government bond yields, Report for AusNet Services, CitiPower, Powercor and United Energy*, 23 November 2020.

18 AusNet Services, *Electricity Distribution Price Review 2022–26 Part III*, January 2020, pp. 212-214; AusNet Services, *Revised regulatory proposal 2022–26,* December 2020, pp. 124-125.

19 AER, *Final position, Regulatory treatment of inflation*, December 2020.

20 AusNet Services, *Revised regulatory proposal 2022–26,* December 2020, p. 127.

Our previous approach to estimate expected inflation used a 10 year average of the RBA's headline rate forecasts for 1 and 2 years ahead, and the mid-point of the RBA's target band—2.5 per cent—for years 3 to 10. The period of 10 years matches the term of the rate of return.

Our inflation review considered that this should be augmented by:[21]

- Shortening the target inflation horizon from ten years to a term that matches the regulatory period (typically five years).
- Applying a linear glide-path from the RBA's forecasts of inflation for year 2 to the mid-point of the inflation target band (2.5 per cent) in year 5.

The key reasons for these changes are:[22]

- There was a mismatch between our estimate of expected inflation over a 10 year term, and our roll forward of the RAB, which is done over a 5 year term. We consider that shortening the inflation term to match the regulatory period, although creating a mismatch with the term of the rate of return, is the more critical mismatch to resolve. This is because of the sustained decline in the required rate of return and the increased difference between 5 and 10 year inflation expectations due to short-term fluctuations in inflation expectations.
- Applying a glide-path acknowledges that it is likely to take longer than previously for inflation to revert to the mid-point of the RBA’s target band following periods of sustained low or high inflation.

We considered that these changes will provide service providers a reasonable opportunity to more accurately recover their efficient costs in an increasingly changing market to better serve consumers with the energy services they want in the long term. Broadly, this was because we take out what we expect to put back into the RAB through our regulatory models.

3.3 Capital raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the operating expenditure (opex) forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt.

On the other hand, we include equity raising costs in the capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

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21 AER, *Final position, Regulatory treatment of inflation*, December 2020, p. 6.

22 AER, *Final position, Regulatory treatment of inflation*, December 2020, p. 6.

Our final decision forecasts for debt and equity raising costs are included in Attachment 6 (opex) and Attachment 5 (capex) attachments, respectively. In this section, we set out our assessment approach and the reasons for those forecasts.

3.3.1 Equity raising costs

Equity raising costs are transaction costs incurred when a service provider raises new equity. We provide an allowance to recover an efficient amount of equity raising costs.

We apply an established benchmark approach for estimating equity raising costs. This approach estimates the costs of two means by which a service provider could raise equity—dividend reinvestment plans and seasoned equity offerings. It considers whether a service provider's capex forecast is large enough to require an external equity injection to maintain the benchmark gearing of 60 per cent.[23]

Our benchmark approach was initially based on 2007 advice from Allen Consulting Group (ACG).[24] We amended this method in our 2009 decisions for the ACT, NSW and Tasmanian electricity service providers.[25] We further refined this approach in our 2012 Powerlink decision.[26]

Our benchmark approach is implemented in the post-tax revenue model (PTRM) to estimate equity raising costs. Other elements of our decision act as inputs to this assessment, particularly the level of approved capex and the rate of return on equity. It also requires an estimate of the dividend distribution rate (sometimes called the payout ratio) as an input into calculating equity raising costs. The dividend distribution rate is also estimated when we estimate the value of imputation credits. We consider that a consistent dividend distribution rate should be used when estimating both the value of imputation credits and equity raising costs.

We note AusNet Services has proposed to use our approach to estimate equity raising costs.[27] We have updated our estimate for this regulatory control period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

3.3.2 Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced as well as the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction

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23 AER, *Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook*, 29 January 2015, pp. 15, 16 & 33. The approach is discussed in AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

24 ACG, *Estimation of Powerlink's SEO transaction cost allowance – Memorandum*, 5 February 2007.

25 For example, see: AER, *Final decision, NSW distribution determination 2009–10 to 2013–14*, April 2009, appendix N.

26 AER, *Final decision, Powerlink Transmission determination 2012–13 to 2016–17*, April 2012, pp. 151–152.

27 AusNet Services, *Revised regulatory proposal 2022–26,* December 2020, p. 126.

costs. We provide an allowance in opex to recover an efficient amount of debt raising costs.

Current assessment approach

Our current approach to forecasting debt raising costs is based on the approach in a report from the ACG, commissioned by the Australian Competition and Consumer Commission in 2004.[28] This approach compensates for the direct cost of raising debt.

It uses a five year window of bond data to reflect the market conditions at that time. Our estimates were updated in 2013 (based on a report by PricewaterhouseCoopers (PwC), which used data over 2008–2013) and most recently in 2019 by Chairmont.[29]

The ACG method involves calculating the benchmark bond size, and the number of bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. This approach looks at how many bonds a regulated service provider may need to issue to refinance its debt over a 10 year period. Our standard approach is to amortise the upfront costs that are incurred in raising the bonds using the service provider's nominal vanilla weighted average cost of capital (WACC) over a 10 year amortisation period. This is then expressed in basis points per annum (bppa) as an input into the PTRM.

This rate is multiplied by the debt component of the service provider's projected RAB to determine the debt raising cost allowance in dollar terms. Our approach recognises that part of the debt raising transaction costs such as credit rating costs and bond master program fees can be spread across multiple bond issues, which lowers the benchmark allowance (as expressed in bppa) as the number of bond issues increases

Proposal

AusNet Services has proposed debt raising costs of 7.93 basis points per annum.[30]

Conclusion on debt raising costs

Our final decision is to accept the method used in AusNet Services' revised proposal which uses an annual rate of 7.93 bppa because it is not materially different from our estimate. In arriving at this decision, we apply the approach from our final decision for SA Power Networks.[31] That is, we use updated Bloomberg data to inform the 'arrangement fee' component of debt raising costs and Chairmont's updated estimates

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28 PricewaterhouseCoopers, *Energy Networks Association: Debt financing costs*, June 2013.

29 Chairmont, *Debt Raising Costs*, 29 June 2019.

30 AusNet Electricity Services Pty Ltd, *Revised regulatory proposal*, *2022–26,* December 2020, p. 126; AusNet Electricity Services Pty Ltd, *AusNet Services - Revised Regulatory Proposal - PTRM Model (2022-26) – March 2021,* March 2021.

31 AER, *Final Decision SA Power Networks Distribution Determinations 2020 to 2025 Attachment 3 Rate of Return*, June 2020.

for the remaining components. We have previously received submissions on concerns with Chairmont's estimate of the arrangement fee.[32]

After assessing these submissions, we recognised that Bloomberg is likely to be the most suitable source of information for the 'arrangement fee' at this time because it is the only published source of data known to us and was previously used to estimate the 'arrangement fee'. In a separate regulatory process, Powerlink submitted a report by Incenta which supported the use of Bloomberg data for estimating the arrangement fee.[33]

Therefore, we have updated the 'arrangement fee' using Bloomberg data and the selection criteria consistent with the PwC report. This leads to an annual total debt raising cost of 8.00 bppa which is not materially different to the estimate proposed by AusNet Services of 7.93 bppa.

Review of debt raising costs approach

Since late 2019 we have been reviewing our approach to setting benchmark debt raising costs, informed by actual debt raising costs data obtained from relevant regulated businesses.

The initial response to our information request showed that each business has its own system for reporting cost categories with the number and naming of categories differing between businesses. As noted in our draft decision, this makes it difficult to aggregate costs across businesses in order to arrive at an accurate estimate.

We have considered whether to continue with further investigation of the industry data. This would entail significant further work and would require regulated businesses to work with each other, as well as us to reconcile costs to mutually agreed categories. Audit assurance would also need to be considered to ensure that costs have been correctly reconciled and allocated.

Further, we have had regard to the overall magnitude of the debt raising costs (that is, a small proportion of overall opex) and the level of imprecision in our current approach. Based on these considerations, we do not think the benefits of further investigation outweigh the costs

Therefore, we have used our current approach for assessing benchmark debt raising costs—that is, using Bloomberg estimates for the 'arrangement fee' and Chairmont's 2019 estimates for the remaining debt raising costs.

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32 For example see: SA Power Networks, *Revised Regulatory Proposal 2020–25: Attachment 3 Rate of Return*, 10 December 2019, pp. 20–22; CEG, *The cost of arranging debt issues*, November 2019.

33 Incenta, *Benchmark debt and equity raising costs*, November 2020.

3.4 True-up for six month extension period

The Order in Council (made pursuant to section 16VE of the *National Electricity (Victoria) Act 2005*) allows the application of placeholder averaging periods to the six month extension period instead of the nominated and accepted averaging periods, if we consider it necessary or expedient for making the variation decision.[34]

The Order also provides for making appropriate adjustments in the 2021–26 regulatory control period for the difference between applying the nominated and accepted averaging period, and applying the placeholder averaging period.[35]

We applied placeholder averaging periods in our decision for the six month extension period of 1 January 2021 to 30 June 2021.[36] This was due to the unanticipated delay in the passing of the NELA Act, and to facilitate our pricing process – the nominated (and accepted) averaging periods would not have finished in time to allow practical estimation of the final rate of return (based on the accepted averaging periods).

The final rate of return for the extension period is calculated based on the nominated and accepted averaging periods, and in accordance with the modified six month instrument and the Order (see Table 3.3). We consider that the difference with the placeholder rate of return will be recovered through the C-factor as noted in our control mechanisms attachment which leads to a true-up amount of -$0.32 million ($2020–21).

Table 3.3 Final decision on six month extension rate of return (nominal)

	AER decision annualised (2020–21)	AER decision six months (1 Jan 2021–30 Jun 21)
Nominal risk free rate	0.9% [a]	
Market risk premium	6.1%	
Equity beta	0.6	
Return on equity (nominal post–tax)	4.56%	2.25%
Return on debt (nominal pre–tax)	4.80%[b]	2.37%
Gearing	60%	60%
Nominal vanilla WACC	4.71%	2.32%
Expected inflation	2.25%	1.12%

Source: AER analysis.

[a b] Calculated using final nominated and accepted averaging periods.

[34] Order in Council under section 16VE of the NEVA, October 2020, cl. 5(b).

[35] Order in Council made under section 16VE of the *National Electricity (Victoria) Act 2005*, Victoria Government Gazette No. S 549 Tuesday 27 October 2020, cl. 8.

[36] For example, see: AER, *Final decision AusNet Services six-month extension – variation decision*, October 2020, pp. 11–12.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
ACG	Allen Consulting Group
bppa	basis points per annum
capex	capital expenditure
distributor	distribution network service provider
DNSP	distribution network service provider
NEL	National Electricity Law
NELA Act	National Energy Legislation Amendment Act 2020 (Vic)
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 4 Regulatory depreciation

April 2021

AUSTRALIAN ENERGY REGULATOR

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Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

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4 Regulatory depreciation

Depreciation is the amount provided so capital investors recover their investment over the economic life of the asset (return of capital). In deciding whether to approve the depreciation schedules submitted by AusNet Services, we make determinations on the indexation of the regulatory asset base (RAB) and depreciation building blocks for AusNet Services' 2021–26 regulatory control period.[1] The regulatory depreciation amount is the net total of the straight-line depreciation less the indexation of the RAB.

This attachment sets out our final decision on AusNet Services' regulatory depreciation amount. It also presents our final decision on the proposed depreciation schedules, including an assessment of the proposed standard asset lives used for forecasting depreciation.

4.1 Final decision

Our final decision is to determine a regulatory depreciation amount of $850.4 million ($ nominal) for AusNet Services for the 2021–26 regulatory control period. This amount represents an increase of $81.6 million (or 10.6 per cent) to the $768.7 million ($ nominal) in AusNet Services' revised proposal.[2] It is $116.9 million (or 15.9 per cent) higher than the regulatory depreciation amount determined in the draft decision. The key reason for the increase compared to our draft decision is the lower expected inflation rate that resulted from our inflation review and was implemented in the most recent version of the post-tax revenue model (PTRM).[3]

The regulatory depreciation amount is the net total of the straight-line depreciation, less the inflation indexation of the RAB. The straight-line depreciation is impacted by our decision on AusNet Services' opening RAB as at 1 July 2021 (Attachment 2), forecast capital expenditure (Attachment 5) and asset lives. Our final decision straight-line depreciation for AusNet Services is $17.1 million lower that its revised proposal. This is mainly due to the lower forecast capital expenditure (capex) in our final decision.

The indexation on the RAB is impacted by our decision on AusNet Services' opening RAB (Attachment 2), forecast capex (Attachment 5) and the expected inflation rate (Attachment 3). Our final decision indexation on AusNet Services' forecast RAB is $98.7 million lower than its revised proposal. This is largely because we decided on an expected inflation rate of 2 per cent per annum for this final decision, compared with the inflation rate of 2.37 per cent per annum that AusNet Services included in its revised proposal. The lower indexation has more than offset the decrease in straight-line depreciation (since indexation is deducted from the straight-line depreciation),

1 NER, cll. 6.12.1, 6.4.3.

2 AusNet Services, *Revised Regulatory Proposal - PTRM Model (2022–26)*, updated 24 March 2021.

3 AER, *Electricity distribution PTRM (version 5)*, April 2021.

which has resulted in a higher regulatory depreciation amount compared to the revised proposal.

In coming to this final decision on AusNet Services' straight-line depreciation:

- We accept AusNet Services' revised proposed straight-line method to calculate the regulatory depreciation, which is consistent with our draft decision.
- We accept AusNet Services' revised proposal to continue with the year-by-year tracking approach to implement straight-line depreciation of existing assets, consistent with our draft decision. However, we have updated the inputs in the depreciation model for the forecast equity raising costs, forecast depreciation and nominal rate of return inputs for the six month period of 1 January to 30 June 2021 (the six month 2021 period), consistent with the roll forward model (RFM).
- We accept AusNet Services' revised proposed asset classes and standard asset lives, which are consistent with our draft decision.
- We accept AusNet Services' revised proposed approach to calculate the accelerated depreciation of intelligent electronic devices relays and remote terminal units as it is consistent with our draft decision.
- We accept AusNet Services' revised proposed accelerated depreciation of approximately $3.9 million of other assets, in particular high bushfire risk assets which have been, or are forecast to be, replaced as part of the safety programs approved in the rapid earth fault current limiter contingent project applications. This is consistent with our draft decision.
- As discussed in Attachment 2, we accept AusNet Services' revised proposed end of period adjustment for capitalised property leases which adopted our draft decision approach. This included an update to the remaining life to 8.3 years from 8.4 years.[4]

Table 4.1 sets out our final decision on the forecast regulatory depreciation amount for AusNet Services over the 2021–26 regulatory control period.

Table 4.1 Final decision on AusNet Services' depreciation amount for the 2021–26 regulatory control period ($ million, nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Straight-line depreciation	278.0	259.6	262.8	270.7	274.8	1345.9
Less: inflation indexation on opening RAB	93.1	96.3	99.8	102.3	104.0	495.6
Regulatory depreciation	**184.9**	**163.2**	**163.0**	**168.5**	**170.8**	**850.4**

Source: AER analysis.

4 AusNet Services made this update to reflect actual 2019 capex.

Year-by-year tracking approach

For this final decision, we accept AusNet Services' revised proposal to continue using the year-by-year tracking approach to calculate the forecast straight-line depreciation amounts for its asset values as at 1 July 2021. This approach (in addition to grouping assets by type via asset classes) tracks the asset classes on a year-by-year basis to implement straight-line depreciation. This is consistent with our determination for AusNet Services' previous regulatory control period of 2016–20.

In the draft decision, we required some minor modelling adjustments to AusNet Services' year-by-year tracking depreciation model used for implementing straight-line depreciation.[5] AusNet Services' revised proposal adopted all our draft decision changes. It also updated the estimated capex for 2020 and the six month 2021 period in the revised proposed depreciation model.[6] For the reasons discussed in Attachment 2, we accept the updated capex in the revised proposed RFM. Therefore, we also accept that the updated capex in the depreciation model is appropriate as it is consistent with the RFM.

Accelerated depreciation

For this final decision, we accept AusNet Services' revised proposal on accelerated depreciation for its existing assets over the 2021–26 regulatory control period. This is consistent with our draft decision.

AusNet Services' revised proposal adopted our draft decision for accelerated depreciation comprising:

- A reallocation of $196.6 million for the 'Secondary systems (pre 2016)' asset class. Of this reallocation, $155.3 million will depreciate over the 2021–26 regulatory control period.
- A reallocation of $3.9 million for other primarily high bushfire risk assets.

Energy Consumers Australia (ECA) submitted that there is not currently a consistent and agreed approach for accelerated depreciation and that we need to review our approach in the context of affordability and consistency.[7] It therefore did not support adopting accelerated depreciation for the revised proposals from the Victorian distributors.

We note ECA's concern, but we have considered this matter in detail in our draft decision. As set out in our draft decision, we reviewed the information before us and

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5 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, Attachment 4 – Regulatory Depreciation*, September 2020, pp. 11–12.

6 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022-26),* updated 24 March 2021.

7 ECA, *Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 5–6.
ECA (via its consultant Spencer&Co), *Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 12.

decided to reduce the proposed accelerated depreciation amount for the 'Secondary systems (pre 2016)' asset class by $43.4 million.[8] We also considered the available data gave us scope to track the depreciation for the different asset types, resulting in about $30.9 million of the accelerated depreciation amount being recovered in the 2026–31 regulatory control period, rather than in the 2021–26 regulatory control period.

Standard asset lives

For this final decision, we accept AusNet Services' revised proposed standard asset lives for its asset classes in respect of the forecast capex to be incurred for the 2021–26 regulatory control period. They are consistent with our draft decision.

AusNet Services' revised proposal did not forecast any benchmark equity raising costs for the 2021–26 regulatory control period, based on the method employed in the PTRM. Consistent with this, for the final decision PTRM we estimate zero equity raising costs. Accordingly, we do not need to set a standard asset life for the 'Equity raising costs' asset class.

The Victorian Community Organisations (VCO) submitted that the Victorian distributors apply different depreciation schedules with asset lives that also differ from replacement capital expenditure (repex) assessments.[9] As we noted in the draft decision, the repex assessments look at assets in more detail at a disaggregated level than the broader depreciation assessment.[10] We also note that in addition to asset lives, repex models also consider performance of the asset as part of assessing when repex should occur. We note the VCO's concerns, but consider that the asset lives used in depreciation schedules of the Victorian distributors are appropriate based on the composition of each asset class.

The VCO's submission also raised an additional concern that AusNet Services' accelerated depreciation does not affect the remaining life of the broader 'source' asset class(es) from which faster-depreciating assets are being removed.[11] It submitted that the remaining life of any such source asset class should be increased 'so that the average depreciation is the same before and after the change'.[12]

We consider that by definition, accelerated depreciation will increase the straight-line depreciation amount in the short term. We also consider that the depreciation profile of a broader source asset class should be appropriately adjusted to reflect the removal of

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8 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 4 – Regulatory Depreciation*, September 2020, pp. 12–15.

9 VCO, (via its consultant Headberry Partners), *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 31-32.

10 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 4 – Regulatory Depreciation*, September 2020, p. 17.

11 In AusNet Services' case, these asset classes are 'Subtransmission' and 'Distribution system assets'.

12 VCO (via its consultant Headberry Partners), *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26* January 2021, pp. 31–32.

the faster-depreciating assets. Therefore, a year-by-year tracking depreciation model will typically reflect a reallocation of such assets for accelerated depreciation as:

- A positive depreciation adjustment for the target asset class into which the faster-depreciating assets are transferring.
- A negative depreciation adjustment for the source asset class from which the faster-depreciating assets are being removed. This negative depreciation adjustment therefore reduces the total rate of depreciation for the source asset class.

We are satisfied that the above adjustments have been appropriately made in AusNet Services' depreciation model.

Table 4.2 sets out our final decision on AusNet Services' standard asset lives for the 2021–26 regulatory control period. We are satisfied the standard asset lives would lead to a depreciation schedule that reflects the nature of the assets over the economic lives of the asset classes. Further, the sum of the real value of the depreciation attributable to the assets is equivalent to the value at which the assets were first included in the RAB for AusNet Services.[13]

Table 4.2 Final decision on AusNet Services' standard asset lives for the 2021–26 regulatory control period (years)

Asset class	Standard asset life
Subtransmission	45.0
Distribution system assets	50.0
SCADA/Network control	10.0
Non-network general assets - IT	5.0
Non-network general assets - other	5.0
Land	n/a
Non-network leasehold land & buildings – 2021–22	23.7
Non-network leasehold land & buildings – 2025–26	5.0
Buildings - capital works[a]	40.0
In-house software[a]	5.0
Equity raising costs[b]	n/a

Source: AER analysis.

(a) New asset class created for the PTRM version 4 in order to separate components of buildings and IT related assets that must be depreciated using the straight-line method for tax purposes. Refer to Attachment 7 (corporate income tax) for more detail.

13 NER, cll. 6.5.5(b)(1)–(2).

(b) For this final decision, the forecast capex determined for AusNet Services does not meet a level to trigger any benchmark equity raising costs.

n/a not applicable. We have not assigned a standard asset life to the 'Land' asset class because the assets allocated to it are non-depreciating.

4.2 Assessment approach

We did not change our assessment approach for regulatory depreciation from our draft decision. Attachment 4 (section 4.3) of our draft decision details that approach.[14]

[14] AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, Attachment 4 – Regulatory Depreciation*, September 2020, pp. 6–10.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	capital expenditure
ECA	Energy Consumers Australia
IT	information technology
NER	national electricity rules
PTRM	post-tax revenue model
RAB	regulatory asset base
repex	replacement capital expenditure
RFM	roll forward model
SCADA	supervisory control and data acquisition
VCO	Victorian Community Organisations

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 5 Captial expenditure

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

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Attachment A – Negotiating framework

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5 Capital expenditure

Capital expenditure (capex) refers to the money required to build, maintain or improve the physical assets needed to provide standard control services (SCS). Generally, these assets have long lives and a distributor will recover capex from customers over several regulatory control periods. A distributor's capex forecast contributes to the return of and return on capital building blocks that form part of its total revenue requirement.

Under the regulatory framework, a distributor must include a total forecast capex that it considers is required to meet or manage expected demand, comply with all applicable regulations, and to maintain the safety, reliability, quality, security of its network (the capex objectives).[1]

We must decide whether or not we are satisfied that this forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs (the capex criteria).[2] We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the National Electricity Objective (NEO)).[3]

If we are not satisfied, we must set out the reasons for this decision and a substitute estimate of the total of the distributor's required capex for the regulatory control period that we are satisfied reasonably reflects the capex criteria, taking into account the capex factors.[4]

The *AER capital expenditure assessment outline* explains our and distributors' obligations under the National Electricity Law and Rules (NEL and NER) in more detail.[5] It also describes the techniques we use to assess a distributor's capex proposal against the capex criteria and objectives.

Total capex framework

We analyse and assess capex drivers, programs and projects to inform our view on a total capex forecast. However, we do not determine forecasts for individual capex drivers or determine which programs or projects a distributor should or should not undertake. This is consistent with our *ex-ante* incentive-based regulatory framework and is often referred to as the 'capex bucket'.

Once the *ex-ante* capex forecast is established, there is an incentive for distributors to provide services at the lowest possible cost, because the actual costs of providing services will determine their returns in the short term. If distributors reduce their costs,

1 NER, cl. 6.5.7(a).

2 NER, cl. 6.5.7(c).

3 NEL, ss. 7, 16(1)(a).

4 NER, cl. 6.12.1(3)(ii).

5 AER, *Capex assessment outline for electricity distribution determinations,* February 2020.

the savings are shared with consumers in future regulatory control periods. This incentive-based framework recognises that distributors should have the flexibility to prioritise their capex program given their circumstances and due to changes in information and technology.

Distributors may need to undertake programs or projects that they did not anticipate during the reset. Distributors also may not need to complete some of the programs or projects proposed if circumstances change. We consider a prudent and efficient distributor would consider the changing environment throughout the regulatory control period and make decisions accordingly.

Importantly, our decision on total capex does not limit a distributor's actual spending. We set the forecast at a level where the distributor has a reasonable opportunity to recover its efficient costs. As noted previously, distributors may spend more or less than our forecast in response to unanticipated changes.

5.1 Final decision

We do not accept AusNet Services' revised capex forecast of $1432.9 million ($2020–21). We are not satisfied that its total net capex forecast reasonably reflects the capex criteria. Our substitute estimate of $1384.1 million is 3 per cent below AusNet Services' revised forecast and is 21 per cent below its actual expenditure in the 2016–20 regulatory control period. We are satisfied that our substitute estimate reasonably reflects the capex criteria. Table 5.1 outlines our final decision.

Table 5.1 Final decision on AusNet Services' total net capex forecast ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	333.4	331.3	276.6	248.1	243.4	1432.9
AER final decision	334.6	320.0	265.5	234.1	229.9	1384.1
Difference ($)	1.2	-11.3	-11.1	-14.0	-13.5	-48.8
Difference (%)	0.3	-3.4	-4.0	-5.6	-5.6	-3.4

Source: AusNet Services' revised post-tax revenue model (PTRM) and AER analysis.

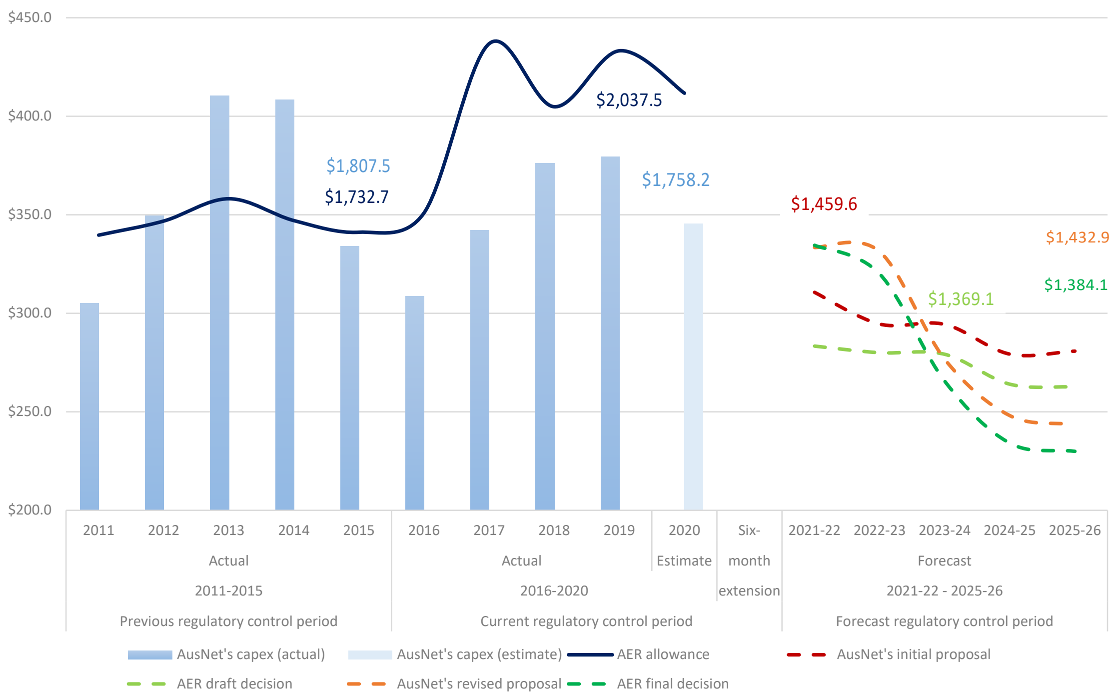
Note: Numbers may not sum due to rounding.

5.2 AusNet Services' revised proposal

AusNet Services' revised capex forecast for the 2021–26 regulatory control period is $1432.9 million. This is 21 per cent lower than its actual capex of $1758.2 million over the current regulatory control period.[6]

Figure 5.1 outlines AusNet Services' historical capex performance against its initial and revised proposals, and our draft and final decisions.

Figure 5.1 AusNet Services' historical vs forecast capex snapshot ($ million, 2020–21)



Source: AusNet Services' revised proposal and AER analysis.

Note: The capex figures reported refer to five-year totals over a regulatory control period. The 2020 estimate has been included in this chart for indicative purposes. We have not used this estimate in our trend comparison.

AusNet Services accepted most aspects of our draft decision. However, it made amendments to the following:

- Its Rapid Earth Fault Current Limiter (REFCL) forecasts for Kalkallo and ongoing compliance
- Its connections forecast, to account for a change in capital contributions due to a decrease in its Weighted Average Cost of Capital (WACC)

6 In this attachment we compare forecast capex with actual capex in the current period; i.e. calendar year 2016 to 2019 pro-rated to five years.

- The allocation of metering costs between SCS and Alternative Control Services (ACS)
- Real cost escalations to include BIS Oxford's updated forecasts.

5.3 Reasons for final decision

We are not satisfied that AusNet Services' total capex forecast reasonably reflects the capex criteria. We are therefore required to set out a substitute estimate.[7] We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and forms part of an overall distribution determination that contributes to achieving the NEO to the greatest degree.

We typically analyse a distributor's total capex forecast from a top-down perspective. This top-down review forms the starting point of our capex assessment to determine whether further detailed analysis is required, but is also used throughout our review process to test the results of our bottom-up assessment.

In our draft decision, we relied more on top-down analysis than our typical category driven analysis to form our substitute forecast capex. This is due to the material decrease in AusNet Services' capex trend and significant top-down efficiency adjustments applied to its total forecast capex. Our adjustments to AusNet Services' initial proposal reflected adjustments to take into account the effect of COVID-19 on connections and real cost escalations.[8]

We have maintained our top-down position from our draft decision. We were satisfied that our total capex forecast reasonably reflected the capex criteria. However, we noted some areas for REFCL augmentation capex (augex), real cost escalations and connections could be updated for further information in our final decision.[9] Our top-down assessment of AusNet Services' capex forecast is attachment 5 of our draft decision.[10]

AusNet Services revised proposal included updates to these categories. However, its revised proposal included new information for REFCL augex and connections that was not a part of its initial proposal and were not identified as areas that required updated information in our draft decision.

However, we also recognise that AusNet Services' did not include augex at Doreen zone substation that could have been added into its revised proposal as a result of

7 NER, cl. 6.12.1(3)(ii).

8 AER, *Draft decision AusNet Services distribution determination 2021–26 - Attachment 5 - Capital expenditure*, September 2020, pp. 15–17.

9 AER, *Draft decision AusNet Services distribution determination 2021–26 - Attachment 5 - Capital expenditure*, September 2020, p. 15.

10 AER, *Draft decision AusNet Services distribution determination 2021–26 - Attachment 5 - Capital expenditure*, September 2020, p. 11–15.

updated demand growth.[11] AusNet Services identified its Customer Forum feedback as a key reason for not including this project in its revised proposal.

As AusNet Services' revised proposal included materially new information that we had not previously assessed, we have undertaken a bottom-up assessment of AusNet Services' REFCL program and its connections forecast.

We discuss our in-depth assessment of these categories in Appendix A.

Stakeholder submissions

The Consumer Challenge Panel, sub-panel 17 (CCP17) noted that our focus on top-down assessment in our draft decision presented a challenge for consumer groups to consider any detail of AusNet Services' revised proposal. The CCP17 considered that if we were to undertake a top-down assessment again, we should focus on connections and REFCL capex as these two categories departed the most from our draft decision.[12] The CCP17 also noted the difficulty in analysing the revised proposal and that where public information was available it was not transparent and potentially misleading.

We agree with the CCP17's submission and as discussed above we have focussed our assessment approach on the areas that depart from our draft decision. We also agree that some areas of AusNet Services' revised proposal were not clear, particularly where there were comparisons with historical capex or our draft decision. We sought additional information from AusNet Services about its forecasts for connections and for REFCL augex.

Energy Consumers Australia (ECA) noted that our focus on historical costs and our assumption that these were considered 'normal' levels of capex may lead to inefficient levels being set due to increased bushfire related capex.[13]

Victorian Community Organisations (VCO) identified similar points to the ECA. The VCO, through its consultants Headberry Partners P/L, expressed concerns that we considered AusNet Services' initial replacement capital expenditure (repex) proposal as reasonable, subject to some minor adjustments.[14] The VCO references Figure 9-17 in AusNet Services' regulatory proposal as evidence that the proposed repex increase is much greater than our observed 4 per cent increase, and therefore needs to be assessed more closely.[15]

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[11] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 58.

[12] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 88–89.

[13] ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 10.

[14] VCO, Submission on the Victorian EDPR Revised Proposal and draft decision *2021–26* – Headberry Partners - Report to the Sponsoring Organisations January 2021, p. 40.

[15] VCO, Submission on the Victorian EDPR Revised Proposal and draft decision *2021–26* – Headberry Partners - Report to the Sponsoring Organisations January 2021, p. 40.; AusNet Services, *Electricity Distribution Price Review 2021–26*, January 2020, p. 76.

We welcome VCO's submission and understand why it may have viewed AusNet Services' proposal in this way. AusNet Services has not categorised its total forecast capex in its regulatory proposal in the same way as in the Regulatory Information Notices (RINs). The VCO references the regulatory proposal but our draft decision analysis relied on RIN data.

Consistent with our typical approach, to allow for comparison of the forecast with historical trend as well as with other businesses, we have relied on the categorisation of total capex in AusNet Services' RINs. Using RIN data, we found that AusNet Services' repex forecast was in line with its current regulatory control period spend.

We also note that our draft top-down assessment took into account non-recurrent capex in the current regulatory control period in our trend assessment. We noted the significance of bushfire related capex in the current regulatory control period. However, even taking this into account, AusNet Services' forecast capex remained materially below historical capex. We also noted that although some categories may increase, other categories, such as recurrent ICT had materially decreased. Where we identified issues with a specific category of capex, we considered its effect on total capex in forming our substitute estimate.

We received several submissions about Distributed Energy Resources (DER) and the use of the value of DER (VaDER).[16]

As highlighted in our draft decision, we commissioned the CSIRO and CutlerMerz to conduct a study into potential methodologies for determining the VaDER in response to stakeholder submissions on our consultation paper 'Assessing Distributed Energy Resources (DER) Integration Expenditure'.[17] We published the CSIRO and CutlerMerz's final value of DER 'VaDER: methodology study' in November 2020 following the release of our draft decision.[18]

We will continue to consider this advice and recommendations, and the Australian Energy Market Commission's current DER rule change consultation process during our ongoing stakeholder engagement and in finalising our DER integration expenditure guideline. We will continue to engage with stakeholders on the development of the DER guideline in the context of these proposed rule changes, which are due for finalisation in mid-2021.

AusNet Services responded to our DER concerns in its revised proposal. We also note that the risk of consumers paying for over-forecast DER capex is mitigated by AusNet Services' commitment to not benefit from the underspend by excluding this category of capex from future capital expenditure sharing scheme (CESS) calculations.

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16 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 85; VCO, Submission on the Victorian EDPR Revised Proposal and draft decision *2021–26*, January 2021, p. 23; Spencer&Co, *Report to Energy Consumers Australia - a review of the Victorian Distribution Networks - Revised Proposals 2021–26*, January 2021, p. 13.

17 AER, *Assessing DER Integrated Expenditure – Consultation Paper,* November 2019.

18 CSIRO and CutlerMerz, *Value of distributed energy resources: Methodology study – Final report,* October 2020.

The Energy Users Association of Australia (EUAA) identified concerns with the relationship between the New Reg process and our level of scrutiny of AusNet Services' capex forecast.[19] The ECA identified similar concerns.[20]

Our focus on the use of a top-down assessment approach was due to multiple aspects of AusNet Services' forecast performing well at the overall capex level. Customer engagement and the New Reg process was an important aspect of AusNet Services' capex forecast. However, stakeholder engagement provided views regarding specific categories of capex (such as DER) rather than overall capex. We note AusNet Services' adjustments across a range of capex categories following its New Reg consultation contributed to AusNet Services' capex forecast performing well in a top-down assessment. We then used this information in conjunction with other top-down assessment techniques such as trend analysis.

Other adjustments

In addition to our assessment of connections and REFCL, we have applied modelling adjustments that are consistent with our draft decision. These include:

- Updating our Consumer Price Index (CPI) real cost escalation forecasts for the most recent forecasts from BIS Oxford and Deloitte Access Economics.
- Adjusting capitalised overheads using our standard 75/25 fixed and variable ratio to reflect our lower substitute capex forecast.
- Maintaining our draft decision metering cost allocations between ACS and SCS. More information on why we have maintained our position is in attachment 16.

Table 5.2 summarises the reasons for our substitute estimate by capex driver. This reflects the way we have assessed AusNet Services' revised total capex forecast. Our findings for each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver. However, we use our findings for each of the capex drivers to assess a distributor's proposal as a whole and arrive at a substitute estimate for total capex where necessary. In addition, as noted above, our decision regarding total capex does not limit a distributor’s actual spending.

Table 5.2 Summary of our findings and reasons by capex driver

Issue	Findings and reasons
Repex	AusNet Services' revised proposal accepted our draft decision for repex with the exception of adopting different metering costs allocated between ACS and SCS. We have maintained our draft decision

[19] Energy Users Association of Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9.

[20] ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 10

Issue	Findings and reasons
	allocation of costs between ACS and SCS.
DER capex	AusNet Services' revised proposal accepted our DER capex forecast.
Augex	AusNet Services accepted our augex draft decision. However, it included updates for its REFCL forecast. We have accepted the majority of AusNet Services' augex forecast but have not included one REFCL project that can be deferred beyond the forecast regulatory control period.
Connections capex	AusNet Services' revised proposal accepted our connections volumes but updated its forecast to reflect a change in its capital contributions and more recent unit rates. We do not consider that AusNet Services' method for adjusting forecast capital contributions for its changed WACC and price path is reasonable. We have also updated connections to reflect more recent Housing Industry Association (HIA) forecasts.
ICT capex	AusNet Services accepted our draft decision for ICT capex.
Other non-network capex	AusNet Services accepted our draft decision for other non-network capex.
Capitalised overheads	AusNet Services accepted our capitalised overheads forecast but adjusted its forecast to reflect our fixed and variable overhead methodology for its revised capex forecast. We have updated this calculation to reflect our substitute capex forecast.
Modelling adjustments	Our substitute capex forecast includes updated CPI and real cost escalations.
Asset disposals	AusNet Services accepted our draft decision for asset disposals.

A Capex driver assessment

This appendix describes our detailed analysis of AusNet Services' capex driver category forecasts for the 2021–26 regulatory control period. These categories are: REFCL and connections capex. All dollar amounts are presented in real $2020–21 unless otherwise stated.

We used various qualitative and quantitative assessment techniques to assess the different elements of AusNet Services' proposal to determine whether it reasonably reflects the capex criteria. More broadly, we seek to promote the NEO and take into account the revenue and pricing principles set out in the NEL.[21] In particular, we take into account whether our overall capex forecast will provide AusNet Services with a reasonable opportunity to recover at least the efficient costs it incurs to:

- provide direct control network services
- comply with its regulatory obligations and requirements.[22]

When assessing capex forecasts, we also consider:

- the prudency and efficiency criteria in the NER are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers to achieve the expenditure objectives.[23]
- past expenditure was sufficient for the distributor to manage and operate its network in previous periods, in a manner that achieved the capex objectives.[24]
- the capex required to provide for a prudent and efficient distributor's circumstances to maintain performance at the targets set out in the service target performance incentive scheme (STPIS).[25]
- the annual benchmarking report, which includes total cost and overall capex efficiency measures, and considers a distributor's inputs, outputs and its operating environment.
- the interrelationships between the total capex forecast and other constituent components of the determination, such as forecast operating expenditure (opex) and STPIS interactions.[26]

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[21] NEL, ss. 7, 7A and 16(1)–(2).

[22] NEL, s. 7A.

[23] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 8–9.

[24] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 9.

[25] The STPIS provides incentives for distributors to further improve the reliability of supply only where customers are willing to pay for these improvements.

[26] NEL, s. 16(1)(c).

A.1 Augex

The need to build or upgrade the network to address changes in demand and network utilisation typically triggers augex. The need to upgrade the network to comply with quality, safety, reliability and security of supply requirements can also trigger augex.

A.1.1 Final decision

We are not satisfied that AusNet Services' revised augex forecast reasonably reflects the capex criteria. We include $214.4 million for augex in our substitute estimate of total capex. This is $5.4 million or 2 per cent lower than AusNet Services' revised forecast. We are satisfied that our substitute estimate forms part of a total capex forecast that meets the capex criteria.

A.1.2 AusNet Services' revised proposal

AusNet Services included $219.7 million for forecast augex in its revised proposal for the 2021–26 regulatory control period. AusNet Services accepted most aspects of our draft decision. However, it updated its REFCL forecast to address some of the concerns we raised in our draft decision.[27]

A.1.3 Reasons for final decision

We have maintained our draft decision assessment of AusNet Services' augex with the exception of its updated REFCL program.

AusNet Services' revised proposal included $151.2 million for REFCL augex for bushfire mitigation obligations. Following the 2009 Victorian Bushfires Royal Commission, legislative amendments were introduced to reduce the likelihood of bushfire starts from electrical equipment faults.[28] These amendments place regulatory obligations to achieve certain protection performance requirements (referred to as ‘required capacity’) at 22 of AusNet Services' zone substations.[29] A REFCL is a protection device typically installed at a zone substation used to achieve the required capacity to reduce the risk of faulted power lines starting bushfires.

AusNet Services has materially changed the composition of its REFCL program since the initial proposal. We have reviewed the changes and our assessment is that most of the revised proposal reasonably reflects the capex criteria. Based on the available information, we consider REFCL-related works at one zone substation can reasonably be deferred into the next regulatory control period. Our final decision substitute includes $145.7 million for REFCL augex.

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27 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 58.

28 *Electricity Safety (Bushfire Mitigation) Regulations 2013* (Vic), *Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017* (Vic) and *Electricity Safety (Bushfire Mitigation Duties) Regulations 2017* (Vic).

29 Achieving required capacity involves reducing the voltage and current on faulted power lines as defined in the *Electricity Safety (Bushfire Mitigation Duties) Regulations 2017*, regulation 7.

What has changed since the initial proposal?

Our draft decision did not adjust the proposed REFCL capex of $147.3 million because we acknowledged that AusNet Services would likely materially change its REFCL forecast in the revised proposal in two areas. First, AusNet Services indicated it may include an update to its Kalkallo zone substation REFCL solution that was not included in the original proposal. Second, a key issue we raised in our draft decision was the material capex proposed for the construction of three new zone substations proposed by AusNet Services as part of its ongoing compliance program.[30] AusNet Services identified that two REFCLs was the maximum number that could be installed at a single zone substation due to software limitations, which necessitated the construction of new zone substations to install sufficient REFCL capacity to meet the bushfire mitigation obligations. In our draft decision, we noted that Powercor proposed three REFCLs at several zone substations and we therefore considered this approach could reasonably be adopted by AusNet Services.

The revised proposal is $3.8 million higher than the initial proposal, which consists of:

- an additional $30.4 million net for Kalkallo zone substation[31]
- a reduction to the ongoing compliance program by $26.6 million, comprising:
    - a $41.6 million reduction due to implementing the three REFCL approach at two of its zone substations (therefore avoiding construction of two new zone substations), and proposing to implement a Remote REFCL on a feeder at another zone substation.
    - a $15.5 million increase due to updated costs associated with five zone substations.
    - a $0.5 million decrease to the remaining tranche two and three capex associated with changes in escalation.

Stakeholders expressed concern with the lack of transparency in the changes

We have closely interrogated the additional information provided by AusNet Services. The CCP17 submitted that it found the changes in the revised proposal REFCL forecast somewhat difficult to follow, especially in the case where the cost reductions were positively emphasised and the increased costs for Kalkallo were not as clear.[32] We agree the changes could have been better explained for stakeholders to follow, and consequently we provide the below clarifications to assist understanding of the changes.

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30 AusNet Services refers to this as its 'augmentation program' for tranche one and two zone substations where there is forecast growth in capacitance in excess of the expected REFCL capacity.

31 The total amount in the forecast period for the revised Kalkallo solution is $38.6 million. The initial proposal already included $8.1 million, as the capex was expected to be incurred in the forecast period from the tranche 3 final decision. Therefore, the net addition to the forecast capex is $30.4 million.

32 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 91–92.

Figure 1 illustrates the total capex in three periods: the current regulatory control period, the January to June 2021 six-month extension, and the 2021–26 regulatory control period. We highlight that:

- At face value, it appears that AusNet Services has increased the capex requirement for REFCL by $3.8 million. This is largely driven by a shift of current regulatory control period capex for Kalkallo into the 2021–26 regulatory control period and revising the proposed solution as the tranche three option was not a viable long-term option.
- The total REFCL capex requirement that AusNet Services expects to incur is $11.0 million lower than that included in the initial proposal. This is due to the $26.6 million reduction in the ongoing compliance program that is partly offset by the $15.6 million increase for the revised Kalkallo solution.
- The total proposed capex for Kalkallo has increased by $15.6 million from the $25.0 million in the tranche three final decision to the $40.6 million.[33] The current regulatory control period capex has been shifted into the 2021–26 regulatory control period. We consider the shift in capex has been appropriately adjusted for with a CESS adjustment and a revenue adjustment.

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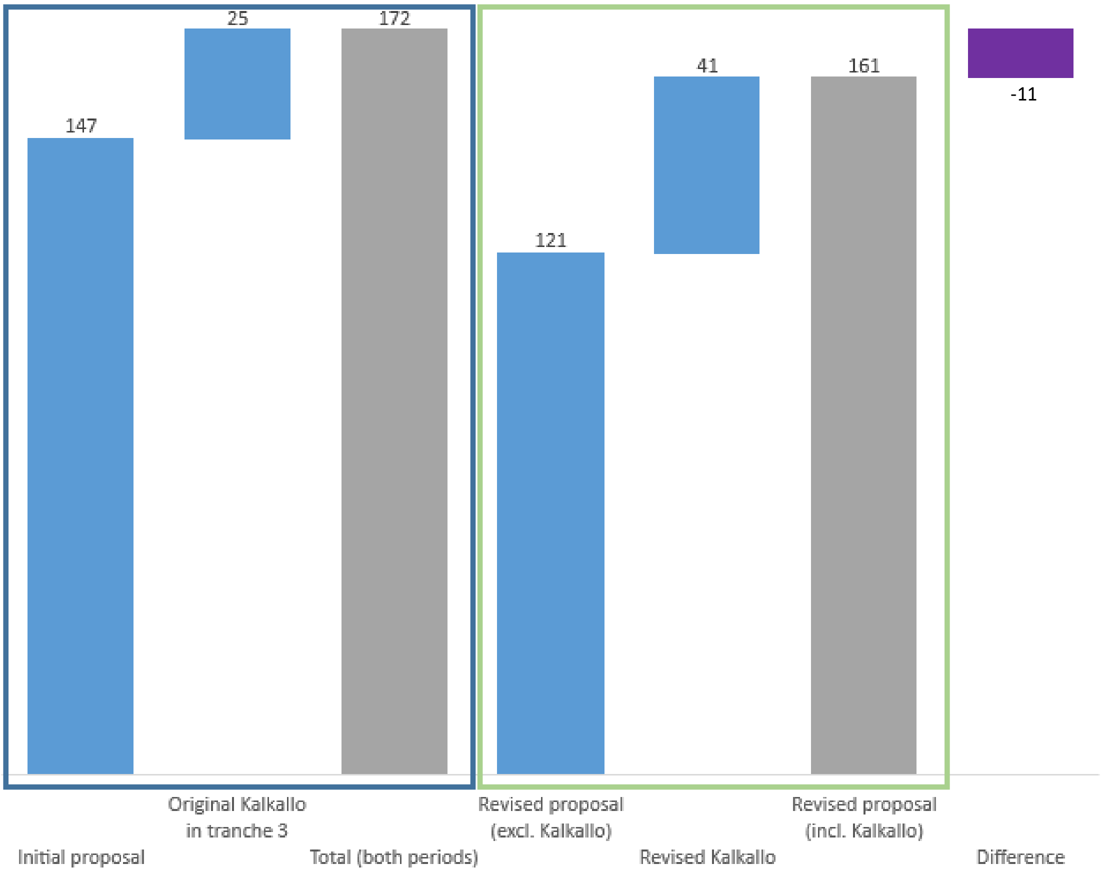
[33] The total $40.6 million capex includes $2.0 million in the January to June 2021 six-month extension. Therefore, $38.6 million is included in the forecast regulatory control period.

Figure 2 Total changes to AusNet Services' expected REFCL capex ($ million, 2020–21)



Source: AER analysis

Notes: Numbers may not sum due to rounding. The total capex includes amounts from the current period, the six-month extension, and the 2021–26 regulatory control period.

In the following section, we describe our assessment of the revised Kalkallo solution and how the shift in capex has been accounted for.

Our assessment of the revised Kalkallo solution

The revised Kalkallo solution is reasonable

We have assessed the proposed solution for Kalkallo and consider it is reasonable given the difficulties in the Kalkallo network, which have been discussed since tranche three in 2019. Our tranche three final decision was made on the best available information at the time, and recognised there may be an updated joint solution with Jemena, as Jemena operates three feeders from Kalkallo zone substation.[34] We

[34] For our final decision for Jemena, see: AER, *Final decision Jemena distribution determination 2021–26 - Attachment 5 - Capital expenditure*, April 2021, pp. 5-16–5-17.

recognise the stakeholder concerns about the increase in cost for Kalkallo and highlight the identified difficulties, as Kalkallo serves a network with existing high capacitive current and forecast growth in capacitive current due to underground networks.[35] The REFCL capacity must exceed the capacitive loading in the network in order to meet the regulations. In the case of Kalkallo, the existing network size requires more than three REFCL units and would potentially require building multiple zone substations in future to meet the required capacity.

AusNet Services' proposed solution essentially intends to reduce the network size by segmenting the network, which involves:[36]

- REFCL-protecting the overhead line on two feeders using a Remote REFCL on each feeder[37]
- installing isolation transformers to separate fully underground network segments and therefore lower the capacitive current
- reconductoring existing overhead line with covered conductor[38] suitable for Energy Safe Victoria (ESV) exemption in the sections between the zone substation and the Remote REFCLs. AusNet Services is progressing the exemption with ESV.

In arriving at our decision, we considered:

- benchmarking costs and reviewing the proposed design. We are satisfied with AusNet Services' proposed costs as they are consistent, reasonable and benchmark well. Despite the Remote REFCL being a new approach, it is essentially a REFCL with an isolation transformer plus associated equipment so we have been able to compare these costs.
- the options analysis was comprehensive. AusNet Services and Jemena engaged technical consultant WSP to undertake detailed options analysis for compliance in the Kalkallo area.[39] AusNet Services has proposed an innovative approach to resolve a complicated issue in the Kalkallo network.
- the proposed solution can meet the longer-term forecast capacitance growth. AusNet Services has indicated that no further work is currently projected (out to 2043) to manage capacitance at Kalkallo.[40] Isolation transformers and Remote REFCL allow for the deferral of zone substation construction, as load growth is not

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35 Underground cables have about 30–40 times the capacitance of overhead conductors.

36 AusNet Services, *Revised Regulatory Proposal 2021–26, REFCL deployment summary report for Kalkallo zone substation AMS 20-408*, December 2020, pp. 13–17.

37 Remote REFCL has been developed by AusNet Services as an alternative option to achieving the required capacity. The Remote REFCL utilises an isolation transformer and REFCL to create a separate downstream network from the zone substation to lower the capacitance seen by the REFCL, where the REFCL protects downstream overhead line. It is installed on the feeder, instead of the typical installation at the zone substation.

38 Covered conductor provides greater reduction in fire consequence than REFCL-protected bare wire. AusNet Services, *Stakeholder workshop for proposed Kalkallo REFCL implementation*, 16 March 2021.

39 WSP, *Economic options to maintain REFCL compliance at Kalkallo and Coolaroo zone substations*, December 2019.

40 AusNet Services, *information request 075*, January 2021.

the driver for investment. In the future, if load growth does justify construction of a new zone substation (after demand management and other non-network options are considered), the isolation transformers and REFCL units are salvageable and can be redeployed in other parts of the network.

- the additional information we requested from AusNet Services has sufficiently satisfied us that the proposed capex is prudent and efficient. Further, we have had multiple meetings with AusNet Services to discuss the technical aspects of the solution.

AusNet Services' adjustments to account for the shift in project timing

As there was a partial capex allocation for Kalkallo in the current regulatory control period, AusNet Services proposed to account for the shift in project timing with a:

- CESS adjustment of -$4.5 million to account for the shift of current regulatory control period capex to the 2021–26 regulatory control period.
- Revenue adjustment of -$0.7 million to pass back to customers the revenue received but not spent for Kalkallo.[41]

We accept the proposed adjustments.

Changes to the ongoing compliance program

We are satisfied that the proposed capex for ongoing compliance at seven out of eight zone substations is prudent and efficient. In particular, the significant reduction in capex for adopting the three REFCL approach at two zone substations is appropriate and consistent with Powercor's approach. We have reviewed the updated solutions and revised costs for these zone substations, and are satisfied the proposed capex is prudent and efficient.

Additional works at Ringwood North can reasonably be deferred

AusNet Services proposes to install a second REFCL unit at Ringwood North zone substation because it is likely to approach the REFCL capacity in 2026–27, which is in the subsequent regulatory control period.[42] We requested updated capacitance forecasts from AusNet Services to support the ongoing compliance program for tranche one and two zone substations where REFCL capacity is likely to be exceeded in the 2021–26 regulatory control period.[43]

On the balance of the information provided, we do not accept that the proposed capex is prudent because the project can reasonably be deferred into the subsequent regulatory control period (2026–2031). Specifically:

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41 AER, *Final decision AusNet Services distribution determination 2021–26 - Attachment 1 - Annual revenue requirement*, April 2021, p. 1-5.

42 AusNet Services, *Revised Regulatory Proposal 2021–26 - REFCL compliance maintained planning report for Ringwood North zone substation AMS 20-402*, December 2020, p. 15.

43 AusNet Services, *information request #075*, January 2021.

- the forecast exceedance is marginally higher by 1.7 A at the end of 2027.[44] Given the proposed timing of works, there is sufficient lead time to undertake these works in the subsequent regulatory control period.
- compared to the initial capacitance forecasts we requested,[45] AusNet Services has changed the isolation rate from 20 per cent to zero for the Central Region.[46] This change is unsupported and suggests there is no opportunity for isolating sections of underground network segments and reducing capacitance. This change results in a 25 per cent increase to the capacitance forecast at Ringwood North compared to the original forecasts. Including the original forecast capacitance growth suggests that the likely exceedance is not until the end of 2028.
- should the capacitance exceed the REFCL capacity sooner than forecast, AusNet Services can manage this within the total capex portfolio as the proposed costs are 0.4 per cent of the total forecast capex. Further, there may be lower cost options to manage the capacitance in the interim and defer the installation of the REFCL unit into the subsequent regulatory control period if required.

Capacitance forecasting for future resets

Powercor and AusNet Services used different approaches to forecasting capacitive charging current. Ongoing compliance was a significant component of the REFCL forecast capex. This is due to the forecast growth in network capacitance, primarily driven by growth in underground networks with no bushfire risk. We will closely consider these forecasts compared to the actual capacitance at the next reset if required. We encourage the distributors to continue considering alternative options and exploring possible exemptions to lower costs for consumers for neutral or improved bushfire-risk outcomes.

A.2 Connections capex

Connections capex is expenditure incurred to connect new customers to the network and, where necessary, augment the shared network to ensure there is sufficient capacity to meet new customer demand.

A.2.1 Final decision

We are not satisfied that AusNet Services' revised capex forecast reasonably reflects the capex criteria. We include $278.7 million for gross connections and $106.6 million for capital contributions. This is a 47 per cent and 67 per cent decrease relative to AusNet Services' revised proposal. The total effect on net connections is $36.2 million.

We consider AusNet Services’ contributions would decrease by materially less if it used a calculation method that better reflects the intention of the regulatory framework.

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[44] The existing REFCL unit at Ringwood North has a capacity of 125 A.

[45] AusNet Services, *information request 004,* April 2020.

[46] Isolation rate is an assumption about the proportion of sites suitable for installing isolation transformers.

In addition, AusNet Services did not originally account for the effect of its proposal to charge large embedded generators for the economic tax cost of their connections, or the effect of a recent Federal Court ruling regarding the tax treatment of gifted assets. However AusNet Services has agreed with our proposed regulatory accounting treatment for this issue, in response to an information request.

The change to gross connections is due to regulatory accounting treatments reflecting AusNet Services' proposed taxation charges for large embedded generators and a recent Federal Court decision regarding the taxation treatment of 'gifted' assets. The change to capital contributions is based on accounting for the effect that changes to AusNet Services' WACC and price path, using an approach consistent with our guideline. We have also updated our adjustment for COVID-19 for more recent HIA data, and applied it to residential connections only.

A.2.2 AusNet Services' revised proposal

AusNet Services initially proposed $529.6 million for gross connections and $352.3 million for capital contributions. Our draft decision revised these both down by 8 per cent (for net connections of $177.3 million), based on the estimated effect of COVID-19 on the construction industry.

In AusNet Services' revised proposal it forecast $530.1 million for gross connections and $321.9 million for capital contributions; an increase in net connections of $48.2 million compared to our draft decision. AusNet Services introduced adjustments to its forecast contributions for the effects of changes to its WACC, prices and marginal costs of reinforcement; it increased unit rates based on updated data; and forecast higher volumes for large embedded generator connections.[47]

A.2.3 Reasons for draft decision

Effect of WACC and Prices on Capital contributions

Generally, customers pay a capital contribution to connect to the network to cover the costs of connecting them (incremental cost), insofar as they exceed the net present value of the network use charges they are expected to pay over the life of that connection (incremental revenue). AusNet Services argued that changes to distribution tariffs and the WACC over the next regulatory control period will lead to lower capital contributions, by increasing incremental revenue.

In its connections capex model, AusNet Services did not provide calculations showing the basis for its forecast decline in capital contributions. In response to information requests, AusNet Services provided samples of connections offers with contributions re-calculated using an updated WACC and price path.[48]

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[47] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 51.

[48] AusNet Services, *Information request 084*, March 2021.

We appreciate the information AusNet Services has provided to outline its understanding of this issue. However, we are not satisfied that AusNet Services' calculation method is consistent with the intention of the regulatory framework. AusNet Services' forecast contributions include a charge for the net present value of future incremental opex, calculated as 1.2 per cent of capital costs per year with real escalation. However, our connection charge guideline specifies that operating and maintenance costs (opex) should "have no net impact on the capital contribution payable".[49] AusNet Services also calculated the net present value of incremental revenue based on all forecast distribution use of system (DuOS) charges, including the portion recovering opex. These allowances for opex in incremental cost and in incremental revenue do not cancel out, as typically incremental opex is smaller than any given customer’s share of total opex costs.

In effect, AusNet Services has calculated total incremental cost less total incremental revenue, rather than excluding opex entirely from both sides of the capital contribution formula. AusNet Services' connections policy states that opex will be included in both incremental cost and in incremental revenue, but does not state that the amount of opex will be different in these two cases. We consider that in applying its connections policy, AusNet Services should either include an amount for opex in incremental cost that exactly offsets the amount of opex included in incremental revenue, or exclude opex from both incremental revenue and incremental cost. These two approaches are equivalent.

We consider that the approach most consistent with the intention of the regulatory framework is to exclude opex by multiplying incremental revenue by one minus an operating and maintenance costs (O&M) ratio. The O&M ratio is opex over the current regulatory control period as a proportion of total revenue, calculated from the PTRM.

Our final substitute forecasts contribution ratios by category based on applying this method to the samples AusNet Services provided.

Effect of COVID-19

Our draft decision adjusted connections in the first year of the next regulatory control period, based on dwellings forecast made by the HIA. AusNet Services largely accepted this adjustment, though considered it conservative, and noted they would update their forecast based on new information.

We consider that recent stimulus announcements by the Victorian government justify reversing our COVID-19 adjustment for non-residential connections for all businesses. We also have revised down our HIA adjustment for residential connections based on updated HIA forecast data (from a 42 per cent reduction in the first year to a 37 per cent reduction).

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49 AER, *Connection charge guidelines for electricity retail customers*, June 2012, p. 15.

Gifted Assets

In a recent decision, the Federal Court has ruled that the value of assets that are ‘gifted’ to distribution businesses (in effect constituting a capital contribution) are not taxable income. Before this ruling, we treated gifted assets as both a part of gross capex and capital contributions. This was to allow businesses to recover costs from consumers for the economic tax cost they expected to incur from receiving them.

In response to an information request, AusNet Services agreed to our regulatory accounting treatment to implement this decision.[50] This is to remove gifted assets (excluding rebates) from the gross capex and the capital contributions forecasts. This ensures revenue is no longer recovered from consumers for this purpose.

Large Embedded Generators

We accept AusNet Services’ proposal in its revised connections policy to charge large embedded generators the economic tax cost of connecting to the network. However, AusNet Services’ revised proposal did not account for this change in policy, which would involve double recovering this tax cost.

We engaged with AusNet Services on this issue to develop an appropriate regulatory treatment. The change to AusNet Services' connections policy will mean these connections are entirely funded by the connecting customer. This will mean this cost no longer needs to be recovered from consumers. Similar to the treatment of gifted assets, our final decision removes large embedded generators from both forecast gross capex and capital contributions. This also removes forecasting risk for this category of connections for AusNet and its customers.

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50 AusNet, *Information request 084*, March 2021.

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CPI	Consumer Price Index
DER	Distributed Energy Resources
distributor	distribution network service provider
DUoS	distribution use of system
ECA	Energy Consumers Australia
EUAA	Energy Users Association of Australia
HIA	Housing Industry Association
ICT	information and communications technology
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
O&M	operating and maintenance
opex	operating expenditure
PTRM	post-tax revenue model
REFCL	Rapid Earth Fault Current Limiter
repex	replacement capital expenditure
RIN	regulatory information notice
SCS	standard control services
STPIS	service target performance incentive scheme
VaDER	value of distributed energy resources

Shortened form	Extended form
VCO	Victorian Community Organisations
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 6
Operating expenditure

April 2021

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network and related services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of AusNet Services' proposed opex forecast for the 2021–26 regulatory control period.

6.1 Final decision

Our final decision is to accept AusNet Services' total opex forecast of $1238.7 million ($2020–21),[1] including debt raising costs, for the 2021–26 regulatory control period. Our alternative estimate of $1226.8 million ($2020–21) is not materially different ($11.9 million ($2020–21), or 1.0 per cent, lower) than AusNet Services' updated revised total opex forecast proposal. Therefore we consider that AusNet Services' total opex forecast reasonably reflects the opex criteria.[2]

AusNet Services' revised proposal included a total opex forecast of $1204.1 million ($2020–21) for the 2021–26 regulatory control period. This included a step change for insurance premium increases known as a result of the latest insurance renewals ($10.5 million ($2020–21)) and a proposed cost pass through for future increases. As set out below, under our incentive based framework to achieve efficient outcomes, we consider all forecast insurance premium costs are best included in the total opex forecast. Reflecting this, AusNet Services provided an updated revised proposal with a total opex forecast of $1238.7 million ($2020–21). Most significantly, this included a step change for future insurance premium increases of $45.1 million ($2020–21).[3]

Our final decision opex forecast (AusNet Services' updated revised proposal) is:

- $37.0 million ($2020–21), or 2.9 per cent lower than the opex forecast we approved in our final decision for the 2016–20 regulatory control period[4]
- $109.2 million ($2020–21), or 9.7 per cent higher than AusNet Services' actual (and estimated) opex in the 2016–20 regulatory control period
- $5.3 million ($2020–21), or 0.4 per cent higher than AusNet Services' initial proposal.

Figure 6.1 shows AusNet Services' actual opex, our previous approved forecast, proposed opex for the next five years and our alternative estimate.

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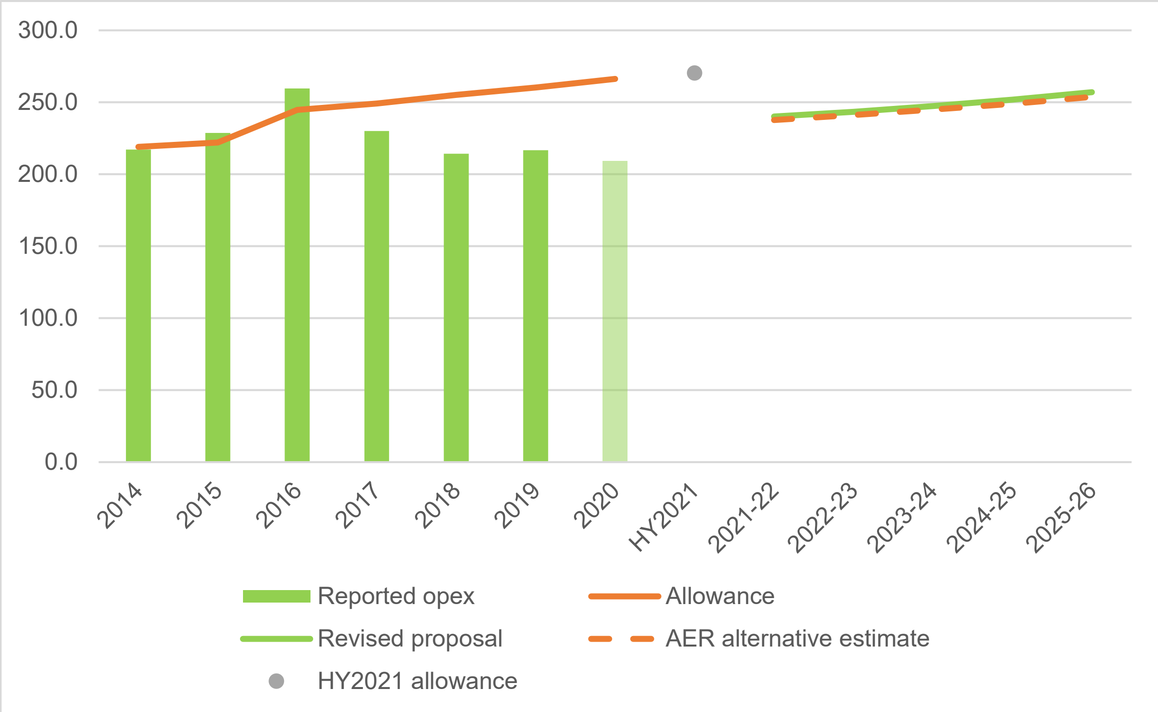
1 AusNet Services, information request #089, March 2021.

2 NER, cl.6.5.6(c).

3 AusNet Services, information request #089, March 2021.

4 Difference is calculated based on the five year 2016–20 period (not including the half year 2021 extension) using unlagged inflation.

Figure 6.1 AusNet Services' opex over time ($ million, 2020-21)



Source: AusNet Services, *Regulatory proposal 2021–26 – Supporting document – Workbook 1 – Regulatory determination,* January 2020; AusNet Services, information request #089, March 2021; AER, *Final Decision – AusNet Services distribution determination 2021–26 – Opex model, April* 2021; AER, *Draft Decision – AusNet Services distribution determination 2021–26 – Opex model,* September 2020; AER analysis.

Note: Opex for 2020 is an estimate.

Table 6.1 sets out AusNet Services' revised proposal, its updated revised proposal (which we accept), and our alternative estimate for the final decision.

Table 6.1 Comparison of AusNet Services' revised proposal and our alternative estimate ($ million, 2020–21)

	AusNet Services' revised proposal	Updated revised proposal	AER alternative estimate	Difference
Base (reported opex in 2018)	1080.1	1080.1	1080.1	–
Base year adjustments	–20.6	–20.6	–24.8	–4.2
Final year increment	75.1	75.1	80.3	5.2
Trend: Output growth	26.4	26.4	27.0	0.7
Trend: Real price growth	14.2	14.2	14.1	–0.1
Trend: Productivity growth	–14.8	–14.8	–15.0	–0.2
Step changes	20.6	55.2	55.2	–0.0
Net category specific forecasts	11.8	11.8	–1.5	–13.4

	AusNet Services' revised proposal	Updated revised proposal	AER alternative estimate	Difference
Total opex (excluding debt raising costs)	1192.7	1227.3	1215.4	–12.0
Debt raising costs	11.3	11.3	11.4	0.1
Total opex (including debt raising costs)	1204.1	1238.7	1226.8	–11.9
Percentage difference to proposal				–1.0%

Source: AusNet Services, *Regulatory proposal 2021–26 – Supporting document 10.06 – Opex model,* December 2020; AusNet Services, information request #089, March 2021*; AER analysis*.

Note: Numbers may not add up to totals due to rounding. Differences are between the AER's alternative estimate and AusNet Services' updated revised proposal. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance. Net category specific forecasts captures the net impact of removing these costs from the base year and re-forecasting as a category specific forecast for the 2021–26 regulatory period.

The following factors contributed to our lower alternative estimate of total opex of 1.0 per cent, compared to the updated revised proposal:

- Our alternative estimate for category specific forecasts is $13.4 million ($2020–21) lower than AusNet Services' proposal. The main driver of this difference is that we have included a lower forecast for guaranteed service level (GSL) payments. AusNet Services' proposed GSL forecast uses a five year average to calculate a transitional payment. We consider a ten year time series more appropriate as it smooths out the impact of abnormal events in the current period.
- For base adjustments, our alternative estimate is $4.2 million ($2020–21) lower than AusNet Services' proposal. The main driver of this difference is that we have included a lower forecast for the reclassification of metering costs, consistent with our draft decision.
- Our final year increment is $5.2 million ($2020–21) higher as we have updated for the latest actual and inflation forecasts.

As noted above, we included in our alternative estimate a step change for insurance premiums. This reflects our view on balance that while there is some uncertainty associated with the forecast insurance premium costs, businesses are best incentivised to achieve efficient cost outcomes by including these in the total opex forecast. Subsequently, AusNet Services provided an updated revised proposal which included a step change for insurance premiums of $45.1 million ($2020–21), which we consider is reasonable and we have included this amount in our alternative estimate. As a result we have not accepted the proposed insurance premium event nominated cost pass through for the 2021–26 regulatory control period.

6.2 AusNet Services' revised proposal

AusNet Services used a 'base–step–trend' approach to forecast opex for the 2021–26 regulatory control period in its revised and updated revised proposals, consistent with our standard approach.

AusNet Services proposed a revised total opex forecast of $1204.1 million ($2020–21) for the 2021–26 regulatory control period.[5] This included a step change for insurance premium increases known as a result of the latest insurance renewals ($10.5 million ($2020–21)) and a proposed cost pass through for future increases. As set out below, under our incentive based framework to achieve efficient outcomes we consider forecast insurance premium costs are best included in the total opex forecast. Reflecting this, AusNet Services provided an updated revised proposal with a total opex forecast of $1238.7 million ($2020–21).[6] This included a step change for future insurance premium increases of $45.1 million ($2020–21).

In applying our base-step-trend approach to forecast opex for the 2021–26 regulatory control period, AusNet Services:[7]

- used opex in 2018 as the base to forecast ($1080.1 million ($2020–21))
- removed costs from the base year (as a non-recurrent efficiency loss) to account for revised Australian Accounting standard AASB 16 relating to leases[8] (–$21.8 million ($2020–21))
- adjusted the base year expenditure to include forecasts for activities which are not fully reflected (metering costs) or it considered should be removed in the base year expenditure (Energy Safe Victoria (ESV) levies) ($1.1 million ($2020–21))
- added the final year increment from the base year of 2018 ($75.1 million ($2020–21))
- applied a rate of change comprising of:
  - real price escalation ($14.2 million ($2020–21))
  - output growth ($26.4 million ($2020–21))
  - productivity (–$14.8 million ($2020–21))
- added forecast step changes for the 2021–26 regulatory control period ($55.2 million ($2020–21))
- added net category specific forecasts for the 2021–26 regulatory control period ($11.8 million ($2020–21))
- added forecast debt raising costs ($11.3 million ($2020–21)).

AusNet Services' updated revised total opex proposal is set out in Table 6.2, noting opex represents 39.5 per cent of AusNet Services' total revenue proposal.[9]

5 AusNet Services, *Revised regulatory proposal 2021–26 – Opex Model,* December 2020.
6 AusNet Services, information request #*089,* March 2021.
7 AusNet Services, information request #*089,* March 2021; AER analysis.
8 AusNet Services*, 2021–26 Revised Regulatory Proposal*, December 2020, p. 76.
9 AusNet Services, *Revised regulatory proposal 2021–26– insurance PTRM Model (2022-26)*, 30 March 2021.

Table 6.2 AusNet Services' revised opex forecast ($ million, 2020–21)

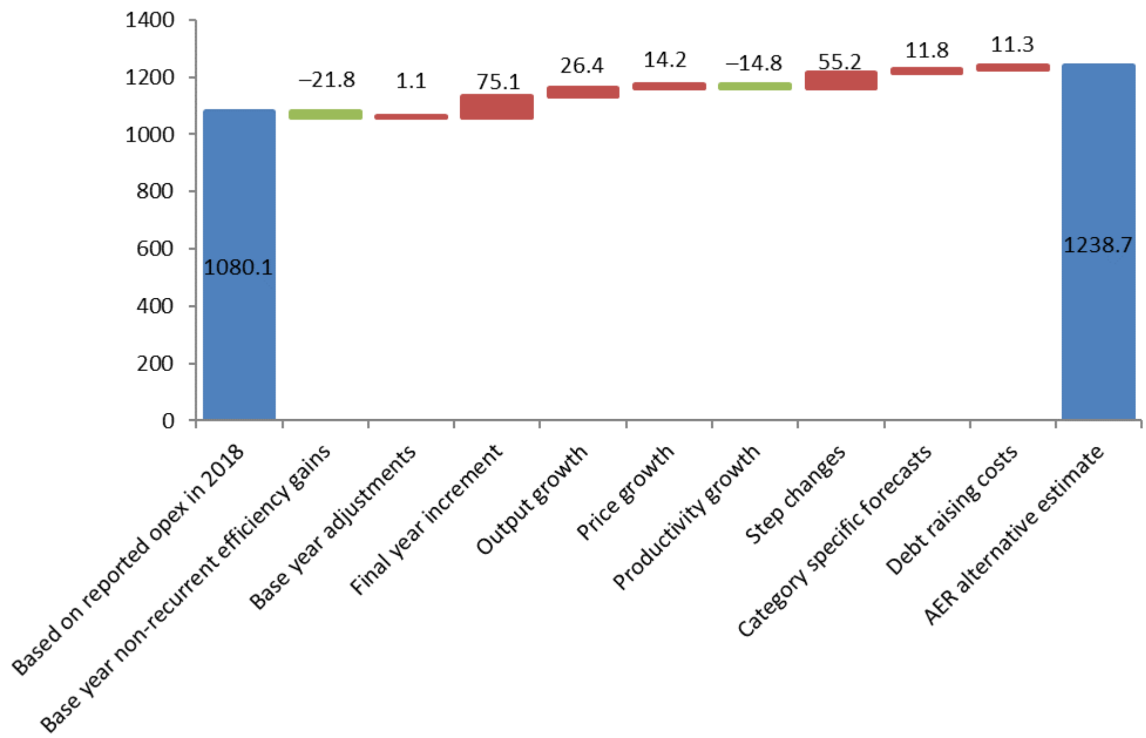
	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Total opex including category specific forecasts	237.9	241.2	244.8	249.1	254.4	1227.3
Debt raising costs	2.2	2.2	2.3	2.3	2.3	11.3
Total opex	240.1	243.4	247.1	251.4	256.7	1238.7

Source: AusNet Services, information request #089, March 2021; AER analysis.

Note: Numbers may not add up to totals due to rounding.

Figure 6.2 shows the different components in AusNet Services' opex proposal as described above.

Figure 6.2 AusNet Services' revised opex forecast ($ million, 2020–21)



Source: AusNet Services, information request *#089,* March 2021; AER analysis.

6.2.1 Stakeholder views

We received five submissions on AusNet Services' 2021–26 revised proposal that raised issues about opex. At a high level, submissions were generally supportive of our draft decision. Submissions provided commentary on various components of the revised proposals, including to note concerns of productivity declines over time. We have taken these submissions, and any other concerns consumers identified into account in developing the positions set out in this final decision. A summary of the opex issues raised in submissions is provided in Table 6.3.

Table 6.3 Submissions on AusNet Services' revised opex proposal

Stakeholder	Issue	Summary
The AER's Consumer Challenge Panel, sub-panel 17 (CCP17), Victorian Community Organisation (VCO), Energy Consumers Australia (ECA)	Base opex	The VCO suggested that a bottom-up sanity check may be useful in evaluating efficiency as all distributors except United Energy have experienced a decline in productivity over time. Further, that distribution businesses have consistently incurred lower opex costs than their allowance suggesting base opex is not efficient. An efficiency adjustment is considered appropriate for both Jemena and AusNet Services.[10] The CCP17 noted that based on the benchmarking results CitiPower, Powercor and United Energy are the more efficient distribution businesses in Australia for all measures, whereas AusNet Services and Jemena have performed poorly.[11] Ausgrid expressed concerns about the AER's benchmarking[12] and suggested an independent review is required. It highlighted inconsistencies and discrepancies between the index models and the econometric models.[13] Consultant for ECA, Spencer&Co expressed similar concerns about the benchmarking results. It considered the benchmarking results to be highly sensitive to inputs and that this presents risks when setting opex using these results. It called for a review of the impact of capitalisation policies on benchmarking.[14]
VCO	Trend	The VCO considered that to determine price growth the most recent data sources should be used (including the Victorian government's December 2020 estimates) and that the labour / materials weights should be the same across all businesses.[15] The VCO supported the AER's approach for developing output growth forecasts using updated information for the final decisions and to address the issues raised in the NERA and Frontier Economics reports. It considered a detailed review of the forecast growth in outputs is required, including for customer numbers (connections), peak demand and energy throughput. It also sought consistency in approach across all businesses.[16] VCO considered the 0.5 per cent per annum productivity growth forecast is too low.[17]
CCP17, VCO	Step Changes	The VCO supported the application of materiality as grounds for examining step changes, in particular the proposed Australian Energy Market Operator (AEMO)

10 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 15–18, 50–51.

11 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 56–57, 104.

12 AER, *Annual Benchmarking Report electricity distribution network service providers*, November 2020

13 Ausgrid, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3–6.

14 Spencer&Co report to ECA*, Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 9.

15 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 52.

16 Headberry Partners report to VCO*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 22, 52.

17 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 52.

Stakeholder	Issue	Summary
		fees and Energy Safe Victoria (ESV) levy. It was generally supportive of the AER's decisions on the step changes in the draft decision.[18] The CCP17 also supported the application of materiality as a guide for determining if proposed step changes are prudent and efficient and discussed the issues raised by CitiPower, Powercor and United Energy in its revised proposal.[19]
VCO, ECA	ESV Levy	The VCO supported the AER draft decision that the ESV levy cost should be absorbed by the distribution businesses.[20] ECA generally supported the distribution businesses position to include fees and charges levied by regulators in the price control mechanism. It considered these costs cannot be controlled and that it is appropriate to pass the costs on to customers via price controls.[21]
CCP17, VCO, Energy Users Association of Australia (EUAA), ECA	Insurance Premiums	The VCO supported analysis of the insurance step change and cost pass through proposals to ensure these costs are not double counted. It noted there is support for developing the most efficient bushfire insurance program, with consumers sharing in the increased costs and risks, including general insurance which has not been impacted by the increased bushfire risk.[22] The CCP17 acknowledged that insurance coverage is decreasing while insurance costs are rising rapidly. It viewed the insurance market changes as material and beyond reasonable budget projections (with these changes likely to be sustained over a long period due to climate change). As such, it considered the insurance step changes to be reasonable.[23] The EUAA viewed AusNet Services as willing to have a reasonable sharing of bushfire risk with its consumers in light of its recent insurance policy decisions and revised proposal. Discussions around the risk sharing of these events between networks, customers and potentially the wider community was encouraged.[24] Consultant for ECA, Spencer&Co supported the steps taken by businesses to mitigate the cost impacts of rising insurance premiums on customers. They also considered that the businesses response to insurance premium increases is reasonable in the circumstances.[25]
CCP17, VCO	IT Cloud	The CCP17 did not oppose AusNet Services' 'cloud based' approach if the AER is convinced that the project is justified (including the technical solution),

18 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 54.

19 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 57–59.

20 Headberry Partners report to VCO*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 55.

21 Spencer&Co report to ECA*, Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18.

22 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 56.

23 CCP17*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 61–63.

24 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 10.

25 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 15.

Stakeholder	Issue	Summary
		provides sound benefits for customers and is not replicating potential Customer Service Incentive Scheme rewards.[26] The VCO supported this step change for AusNet Services if a net benefit for consumers is identified.[27]
CCP17, ECA	GSL	The CCP17 contended allowing businesses to recover GSL costs does not incentivise improved services. It believed businesses should bear the costs for GSL payment categories they have control over (e.g. for late or missed appointments or delays to connections) and 30 per cent of the other payment categories. The CCP17 proposed that the AER actively review the extent to which GSL payments should be met by the business rather than passed to customers. The CCP17 also did not support the 'transitional allowance' proposed by AusNet Services.[28] ECA recommended accepting AusNet Services' $16 million[29] GSL proposal but suggested the design of the scheme should be reviewed as it does not properly penalise businesses for poor performance.[30]
VCO	Innovation Fund	The VCO supported the innovation project proposed by AusNet Services but questioned the practice of charging customers in funding these projects. Instead, it considered is preferable for these projects to be selected through a competitive process and for funds to be administered by an independent external party.[31]
ECA	Metering	The ECA was supportive of a reallocation of metering costs where there is no metering competition, as it will make little difference to consumers.[32]

6.3 Assessment approach

Our role is to form a view about whether to accept a business' forecast of total opex. Specifically, we must form a view about whether a business' forecast of total opex 'reasonably reflects the opex criteria'.[33] In doing so, we must have regard to each of the opex factors specified in the National Electricity Rules (NER).[34]

If we are satisfied the business' forecast reasonably reflects the opex criteria, we must accept the proposed forecast.[35] If we are not satisfied, we must not accept the

26 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 88.

27 Headberry Partners report to VCO*, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 55.

28 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 64–67.

29 The $16 million represents the incremental increase in GSL costs over the 2021–26 regulatory control period relative to the GSL payments incurred in AusNet Services' base year (2018).

30 Spencer&Co report to ECA*, Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 19.

31 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 17.

32 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 18.

33 NER, cl. 6.5.6(c).

34 NER, cl. 6.5.6(e)

35 NER, cl. 6.5.6(c).

proposed forecast and must substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria.[36] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business' proposal, and the materiality of the difference. Further, we are required to consider interrelationships with the other building block components of our decision.[37]

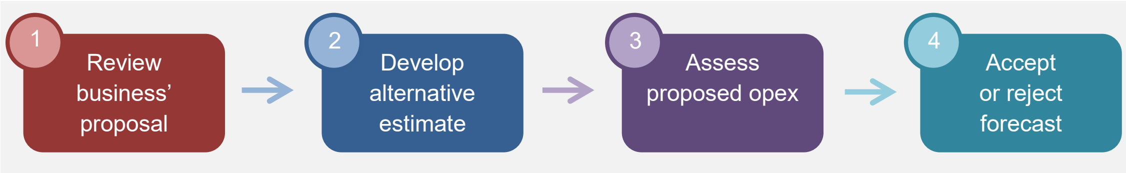
As set out in our draft decision in detail, we generally assess a business' forecast total opex using a 'base-step-trend' approach, as summarised in Figure 6.3.[38]

[36] NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

[37] NEL, s. 16(1)(c).

[38] Our base-step-trend approach is also set out in our expenditure guideline. See AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–24.

Figure 6.3 Our opex assessment approach



1. Review business' proposal

We review the business' proposal and identify the key drivers.

2. Develop alternative estimate

Base — We use the business' opex in a recent year as a starting point (revealed opex). We assess the revealed opex (e.g. through benchmarking) to test whether it is efficient. If we find it to be efficient, we accept it. If we find it to be materially inefficient, we may make an efficiency adjustment.

Trend — We trend base opex forward by applying our forecast 'rate of change' to account for growth in input prices, output and productivity.

Step — We add or subtract any step changes for costs not compensated by base opex and the rate of change (e.g. costs associated with regulatory obligation changes or capex/opex substitutions).

Other — We include a 'category specific forecast' for any opex component that we consider necessary to be forecast separately.

3. Assess proposed opex

We contrast our alternative estimate with the business' opex proposal. We identify all drivers of differences between our alternative estimate and the business' opex forecast. We consider each driver of difference between the two estimates and go back and adjust our alternative estimate if we consider it necessary.

4. Accept or reject forecast

We use our alternative estimate to test whether we are satisfied the business' opex forecast reasonably reflects the opex criteria. We accept the proposal if we are satisfied.

If we are not satisfied the business' opex forecast reasonably reflects the opex criteria we substitute it with our alternative estimate.

6.3.1 Interrelationships

In assessing AusNet Services total forecast opex we took into account other components of its proposal and our determination, including:

- the efficiency benefit sharing scheme (EBSS) carryover—the level of opex used as the starting point to forecast opex (the final year of the current regulatory control period (2016–20)) should be the same as the level of opex used to forecast the EBSS carryover. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years

- the operation of the EBSS in the 2016–20 regulatory control period, which provided AusNet Services an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capital expenditure (capex). For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- concerns of electricity consumers identified in the course of AusNet Services' engagement with consumers.

6.4 Reasons for final decision

Our final decision is to accept AusNet Services' total forecast opex of $1238.7 million ($2020–21), including debt raising costs, in AusNet Services' revenue for the 2021–26 regulatory control period. We have tested AusNet Services' updated revised proposal by comparing it to our alternative estimate of total opex forecast of $1226.8 ($2020–21),[39] which is not materially different (1.0 per cent lower) than AusNet Services' updated revised proposal. Therefore, we are satisfied that AusNet Services' proposed forecast reasonably reflects the opex criteria. On this basis we accept AusNet Services' updated revised total opex proposal.

We discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that AusNet Services would need for the safe and reliable provision of electricity services over the 2021–26 regulatory control period.

AusNet Services proposed base opex to reflect its actual opex in 2018 of $216.0 million ($2020–21).[40] Consistent with our draft decision, we have concluded that AusNet Services' base year opex is relatively efficient, and have relied on AusNet Services' revealed costs in the base year in developing our alternative estimate. We discuss the choice of base year in section 6.4.1.1 and set out our analysis of the efficiency of base year opex in in section 6.4.1.2. We discuss the final year increment to base year opex in section 6.4.1.3 and adjustments to base opex in section 6.4.1.4.

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39 Including debt raising costs.

40 This excludes movements in provisions and DMIA payments. AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 76.

6.4.1.1 Proposed base year

In its revised proposal, AusNet Services noted our draft decision considered 2018 is an appropriate base year. AusNet Services did not propose a different base year in its revised proposal.

Our position has not changed since the draft decision,[41] and we consider 2018 is an appropriate base year. This is because we consider it is representative of the base opex required for the next regulatory control period. While there is a more recent year of actual opex available, 2019, due to the interaction with the EBSS, we are generally indifferent to the choice of base year of a distributor, provided we find AusNet Services opex in the base year is efficient.

6.4.1.2 Efficiency of base year opex

AusNet Services proposed base opex to reflect its actual or 'revealed' opex in the base year 2018 of $216.0 million ($2020–21). As outlined in section 6.3, and in our *Expenditure Forecast Assessment Guideline*, our standard approach for forecasting opex is to use a revealed cost approach. This is because opex is largely recurrent and stable at a total level. Where a distribution business is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations. However, we do not rely on the a priori assumption that the business' revealed opex is efficient. We use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently historically and particularly in the base year.

In this section, we first outline AusNet Services' revealed cost performance, before presenting our benchmarking analysis.

Analysis of AusNet Services' revealed costs

Figure 6.1 shows AusNet Services' opex forecast for the next regulatory control period, its actual opex in the current and previous regulatory control periods, our previous regulatory decisions and our alternative estimate that has informed our final decision.

Our revealed costs analysis for AusNet Services is unchanged from our draft decision.[42]

We have seen a slightly decreasing trend in AusNet Services' opex since 2016. AusNet Services' actual and estimated opex in the current regulatory control period is 11.5 per cent below our opex forecast and its actual opex in the base year of 2018 is 16.1 per cent below our opex forecast. AusNet Services' actual opex in the previous

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[41] AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 22–23.

[42] AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 24.

regulatory control period was on average 1.6 per cent lower per annum than our opex forecast. Since 2011 in aggregate, AusNet Services has spent 5.0 per cent below our opex forecast. Over the current regulatory control period AusNet Services' expected average annual expenditure is $225.9 million ($2020–21), which is $19.9 million higher than over the 2011–15 regulatory control period.

In the current regulatory control period, AusNet Services refreshed its corporate strategy with one key objective being to operate all three of its networks in the top quartile of efficiency benchmarks.[43] In its initial proposal AusNet Services outlined key aspects of its transformation journey to deliver the cost reductions that are in its base year opex. These include being able to better access organisational data and improve asset management, works planning and scheduling. Further, undertaking a variety of outsourcing initiatives, enabling headcount reductions and improving procurement systems and approaches to deliver further savings.[44]

These initiatives and the revealed costs data suggest that AusNet Services has responded to the incentives included in our regulatory regime. It has been able to achieve opex efficiency improvements in several years of the current regulatory control period, and is forecasting to maintain this in the last year of the current period. In line with our approach, we have used our benchmarking tools and other cost analysis to assess whether AusNet Services is operating efficiently, both over time and in base year. We conclude that AusNet Services is relatively efficient.

Benchmarking the efficiency of AusNet Services' opex over time

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. Our *2020 Annual Benchmarking Report* includes information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the National Electricity Market (NEM).[45]

While opex at the total level is generally recurrent, year-to-year fluctuations can be expected. To shed light on AusNet Services' general level of operating efficiency, we first look at the efficiency of AusNet Services' opex over a period of time, using our top-down benchmarking tools, as well as other supporting techniques. This is followed by looking at the efficiency of the base year (2018) in particular and if necessary deriving an alternative estimate of efficient opex in the base year.

Since our draft decision we have published the *2020 Annual Benchmarking Report* which incorporates the 2019 data for distribution businesses. AusNet Services' results are similar, but marginally worse in the *2020 Annual Benchmarking Report* compared to the *2019 Annual Benchmarking Report*. This is due to a slight worsening in opex

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43 AusNet Services, Revised r*egulatory proposal 2022–26, Part III,* January 2020, pp. 136–137.

44 AusNet Services*, Revised regulatory proposal 2022–26, Part III,,*January 2020, p. 137.

45 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020.

productivity and reliability.[46] As discussed further below, for AusNet Services there is also one fewer econometric opex cost function model in the *2020 Annual Benchmarking Report* that we can use (the Translog stochastic frontier analysis (SFA TLG) model over the 2012–19 period). This model produced a relatively lower efficiency score for AusNet Services compared to other models in the *2019 Annual Benchmarking Report*.

Top-down benchmarking

Period-average efficiency scores

In terms of historical performance, our benchmarking results from the *2020 Annual Benchmarking Report* indicate that AusNet Services has been fairly efficient over the 2006–19 period when compared to other distribution businesses in the NEM.[47]

Figure 6.4 shows that over this period AusNet Services ranks sixth out of 13 distribution businesses based on the average efficiency scores from five economic benchmarking models.[48] The scores range from 0.65 (opex multilateral partial factor productivity (MPFP)) to 0.74 (Cobb-Douglas least squares econometrics (LSE CD) model). AusNet Services' average efficiency score across the five models is 0.70.[49] In the draft decision AusNet Services' average efficiency score was 0.71.[50]

The best possible efficiency score is 1.0. We use a 0.75 comparator point to assess the relative efficiency of distribution businesses,[51] noting that we adjust this for operating environment factors (OEFs) not already captured in the modelling below (which we apply to AusNet Services in the next section). Allowing for OEFs enables us to account for some factors beyond a distributor's control that can affect its benchmarking performance.

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46 Economic Insights, *Benchmarking results for the AER - Distribution*, October 2020, pp. 80–81.

47 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020; AER analysis.

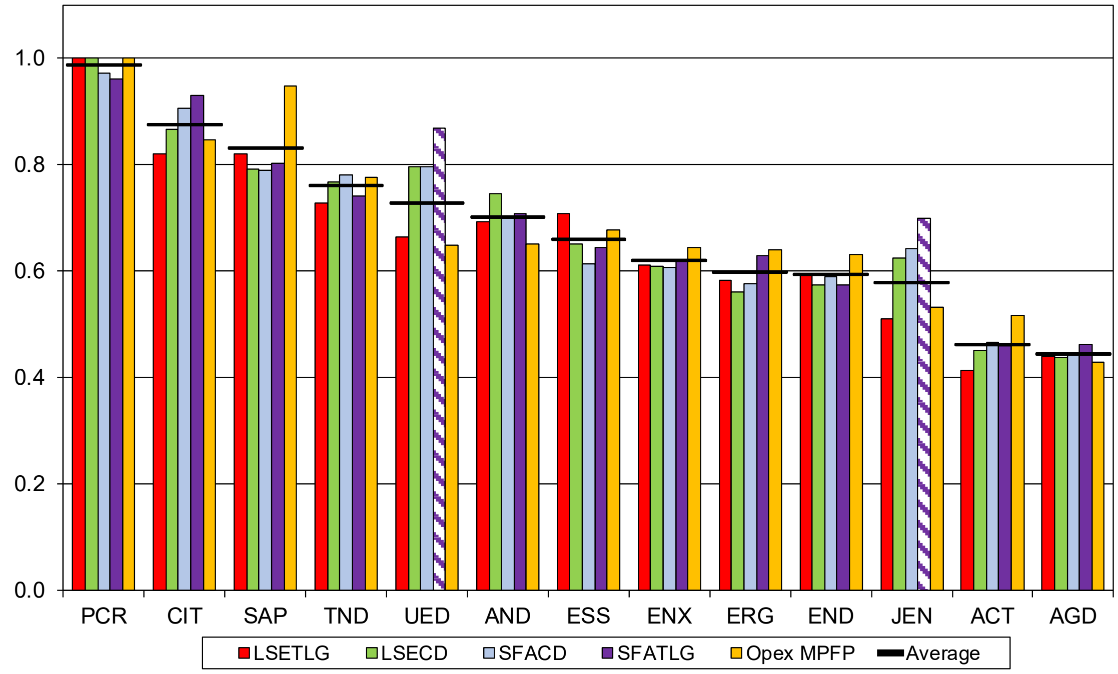
48 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020, p. 32; AER analysis. The five models are the four econometric models – Cobb-Douglas stochastic frontier analysis (SFA CD), Cobb-Douglas least squares econometrics (LSE CD), Translog stochastic frontier analysis (SFA TLG), Translog least squares econometrics (LSE TLG) and the opex multilateral partial factor productivity (MPFP) model.

49 Economic Insights, *Files for 2020 DNSP Economic Benchmarking Report*, 8 October 2020; AER analysis.

50 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure*, September 2020, p. 25.

51 As set out further below, we use the efficiency scores from the four econometric models to derive our estimate of efficient base opex and not the opex MPFP efficiency score.

Figure 6.4 Average opex efficiency scores of distribution businesses, 2006-19



Source: Economic Insights, *Benchmarking results for the AER – Distribution*, October 2020; AER analysis.

Note: Columns with a hatched pattern represent results that do not satisfy the key property (monotonicity – that an increase in output is achieved with an increase in opex) and are not included in the average efficiency score for each distributor (which is represented by the black horizontal line). AND in the figure represents AusNet Services. Other acronyms are: PCR = Powercor, CIT = CitiPower, SAP = SA Power Networks, TND = TasNetworks, UED = United Energy, ESS = Essential Energy, ENX = Energex, ERG = Ergon Energy, END = Endeavour Energy, JEN = Jemena, ACT = Evoenergy, AGD = Ausgrid.

It can take some time for more recent improvements in efficiency by previously poorer performing distribution businesses to be reflected in period-average efficiency scores. Considering this, we have also examined AusNet Services' average performance over the shorter and more recent 2012–19 time period. AusNet Services' average score across these five models over the 2012–19 period is 0.65, and its ranking is eighth of the 13 distributors. Its ranking was seventh in the *2019 Annual Benchmarking Report* (although its average score was also 0.65 in this report).[52] This indicates that AusNet Services' relative efficiency has declined in recent years, compared with its efficiency over the 2006–19 period. In part this is explained by other distribution businesses improving their performance since 2012, meaning AusNet Services' ranking has fallen slightly relative to its peers.

[52] Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020; AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure*, September 2020, p. 26.

A key property required of the econometric opex models is that an increase in output can only be achieved with an increase in inputs (e.g. opex). This is the monotonicity requirement. Cobb-Douglas models automatically impose monotonicity, but the more flexible Translog models (that allow for output elasticities i.e. the responsiveness of opex to an increase in a particular output, to vary for each data point) do not, and so this property may not always hold. Therefore, when estimating the Translog models, satisfaction of the requirement has to be checked for each observation. On the advice of our consultant Economic Insights, we require this property (an increase in outputs requires an increase in inputs) to hold for at least half the data points of a business in order to include the efficiency score from that model in our efficiency assessment.

In AusNet Services' draft decision we did not exclude any Translog results as AusNet Services' results for all models passed this test. As highlighted in the *2020 Annual Benchmarking Report* the number of instances where this requirement is not met has become more prevalent. AusNet Services is one of the affected distribution businesses as its SFA TLG results for the 2012–19 period do not satisfy the key property under our test. This is a change from the *2019 Annual Benchmarking Report* and AusNet Services' draft decision. As noted above, this model produced a relatively lower efficiency score (0.63) compared to some other models for AusNet Services in the *2019 Annual Benchmarking Report*.[53]

Opex MPFP over time

We use the productivity index techniques to enable comparisons of productivity levels over time and between businesses. The multilateral total factor productivity (MTFP) index measures the productivity over all inputs of each business, whereas the opex and capital MPFP indexes measure the productivity of opex or capital inputs respectively.

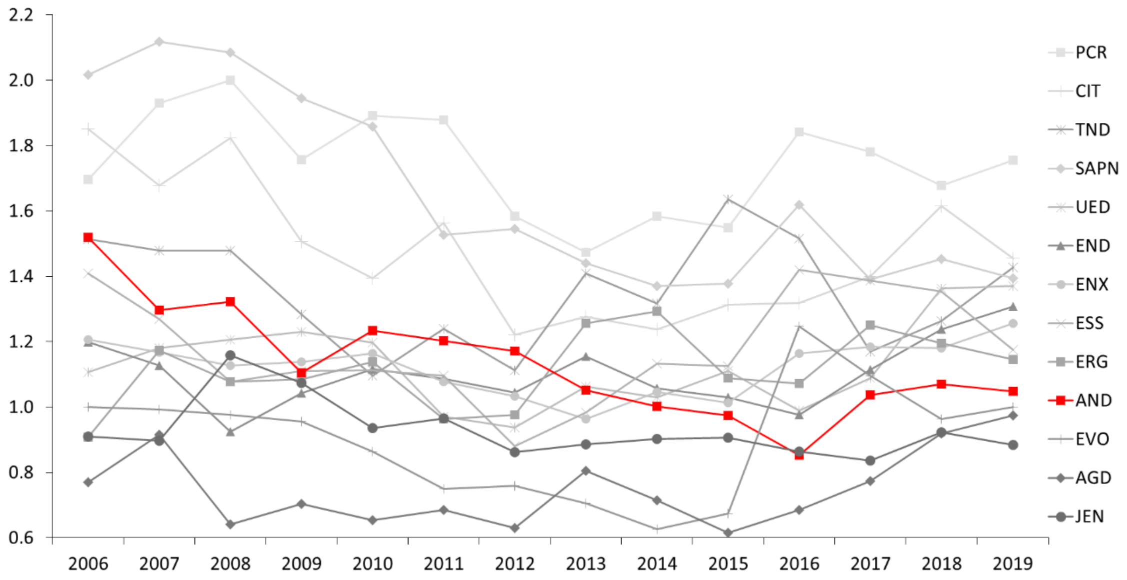
The results from our opex MPFP analysis from the *2020 Annual Benchmarking Report* can be seen in Figure 6.5 (where a higher index score means more efficient). These show AusNet Services' relative efficiency has slowly trended down from 2006 to 2016, after which it improved to achieve a small level of catch-up to the average performing distribution businesses. While its relative performance trended down from 2006 to 2012, AusNet Services typically ranked in the top half of distribution businesses. From 2012 to 2016 AusNet Services' relative performance slipped to the middle to lower range of businesses. Since 2016, AusNet Services' opex productivity has improved substantially, but it has operated at the bottom of the middle group of distribution businesses. This is reflected in its sixth ranking over the 2006–19 period for opex MPFP but its tenth ranking over the 2012–19 period.[54] Its slight worsening in performance over the 2012–19 period occurred at the same time as many other

53 Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020.

54 In the draft decision AusNet Services ranked sixth and tenth in opex MPFP over the 2006–18 and 2012–18 periods respectively. AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure*, September 2020, p. 27.

distribution businesses improved their performance, meaning its ranking fell relative to its peers. These results have not been adjusted to account for OEFs.

Figure 6.5 Opex MPFP by individual distribution businesses, 2006–19



Source: Economic Insights, *Benchmarking results for the AER – Distribution*, October 2020; AER analysis.

Note: AND in the figure represents AusNet Services.

Partial Performance Indicators

We have also examined the relative opex performance of AusNet Services using partial performance indicators (PPIs). The PPI's support other benchmarking techniques because they provide a general indication of comparative performance of distribution businesses in delivering a specific output. However, they are more simplistic measures and rankings for PPIs may be affected by factors outside the control of the distribution businesses and must be analysed with caution, with comparisons generally limited to businesses with similar characteristics, e.g. customer density.

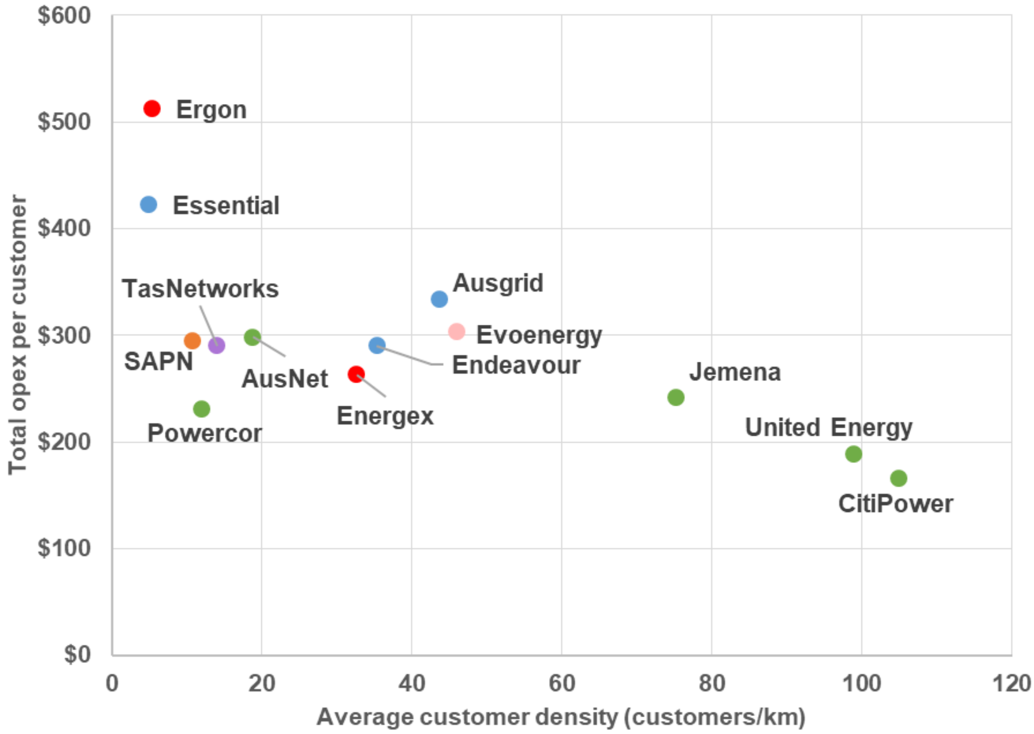
The PPIs in the *2020 Annual Benchmarking Report* are broadly consistent with those from the *2019 Annual Benchmarking Report* used in the draft decision.[55] As such our analysis and conclusions regarding the PPIs in the draft decision are unchanged for this final decision.

AusNet Services tends to perform similar in per customer PPIs, compared with peers that have a similar customer density and performs similar or slightly worse compared to its peers for per circuit PPIs. These observations are generally consistent on a total cost and total opex basis (see Figure 6.6 and Figure 6.7) and for the main opex cost

[55] The *2020 Annual Benchmarking Report* results are for the period 2015-19 and are an update from the 2014-18 results in the *2019 Annual Benchmarking Report*.

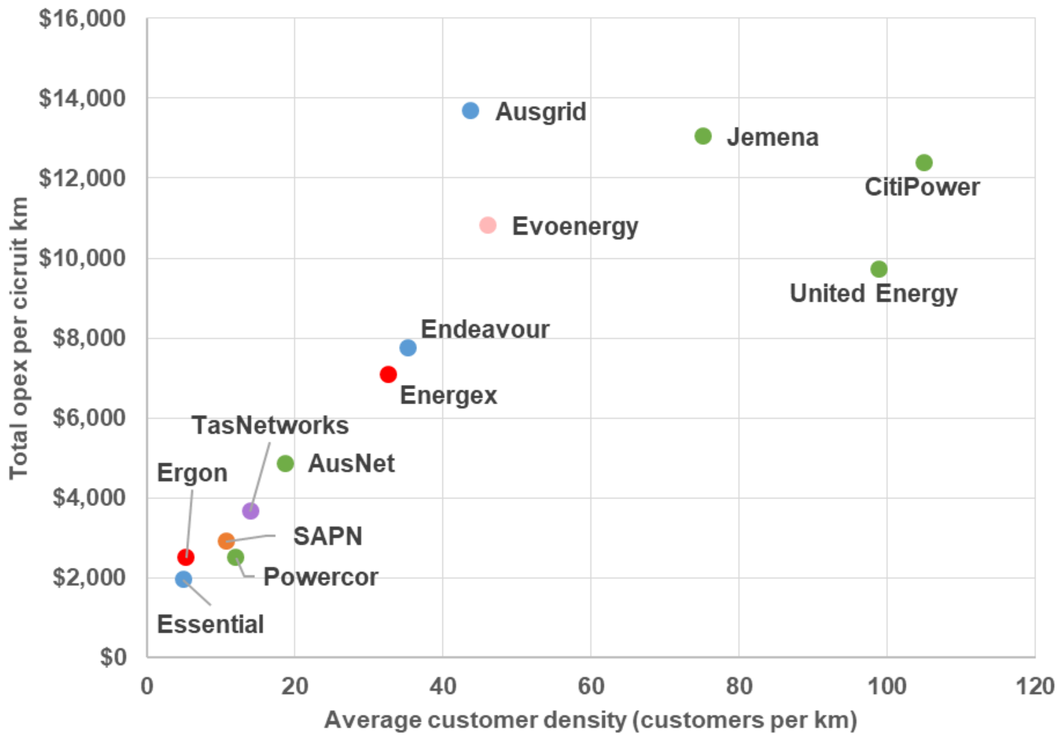
categories (maintenance, vegetation management, emergency response and total overheads). These results suggest AusNet Services is generally similar in its efficiency compared to its peers. As noted above, however, these results need to be treated with caution.

Figure 6.6 Total opex per customer, 2015–19, ($2020–21)



Source: AER analysis.

Figure 6.7 Total opex per circuit line length, 2015–19, ($2020–21)



Source: AER analysis.

Benchmarking the efficiency of AusNet Services' base year opex

Given AusNet Services' model-average opex efficiency score across the two time periods, including its worse top-down efficiency performance over the more recent 2012–19 period, we have undertaken additional analysis. This includes application of our economic benchmarking roll-forward-model, which includes adjusting for OEFs, to more directly test the efficiency of AusNet Services' actual opex in the base year.

The results from our productivity index techniques and econometric opex cost function modelling indicate AusNet Services' 2018 base year opex is not materially inefficient.

Our productivity index techniques allow us to look at the productivity of each businesses total outputs in any particular year. In the base year 2018, AusNet Services is placed tenth on opex MPFP. While its productivity improved in 2018, so did the performance of its peers. This is an indicator that AusNet Services' base year opex may contain some relative inefficiency, however, these results have not been adjusted to account for OEFs and further analysis is required.

Consistent with our standard approach, we have tested this further using the econometric benchmarking incorporating OEF analysis to establish AusNet Services' efficient opex in the base year and if an efficiency adjustment is required. MTFP / MPFP benchmarking is not used as a part of this further testing. We used the same approach in the draft decision.

Econometric benchmarking roll forward modelling

Our econometric models produce average opex efficiency scores for distribution businesses across the 2006–19 and 2012–19 periods respectively. Using our roll-forward-model, we convert these period-average results to estimate the level of network services opex[56] required by a service provider operating in AusNet Services' circumstances in 2018, and compare this to the AusNet Services' actual base network services year opex.

This uses a benchmark comparison point of 0.75. This also adjusts for differences in OEFs between AusNet Services and the benchmark comparators that are not already captured in the modelling (discussed further below). We outline our approach in Box 1.

56 We benchmark distribution businesses on the basis of the network services component of standard control services opex, which comprises the majority of standard control services opex. Network services opex excludes opex categories that are part of standard control services opex, such as opex for metering, customer connections, street lighting, ancillary services and solar feed-in tariff payments.

Box 1 Our approach to estimating efficient base year opex

To derive our efficient estimate of base year opex for businesses, we find the average of the estimated efficient rolled-forward levels of network services opex as determined by each of our econometric models (LSE CD, SFA CD, LSE TLG, SFA TLG). This is done using data over the 2006–19 and 2012–19 periods separately, which means two averages are produced. We then compare this to actual network services opex in the base year.

The first step is to average a business' actual network services opex over the relevant benchmarking period to find the business' period-average network services opex (where relevant, we use the same backcast opex series under the Cost Allocation Method (CAM) applying in 2013–14 as those used for our economic benchmarking).

We then separately compare the business' efficiency scores of each econometric model over that period, against a benchmark comparison point of 0.75. This reflects that we consider the upper quartile of possible efficiency scores are efficient, and reflects our conservative approach to setting a benchmark comparison point.

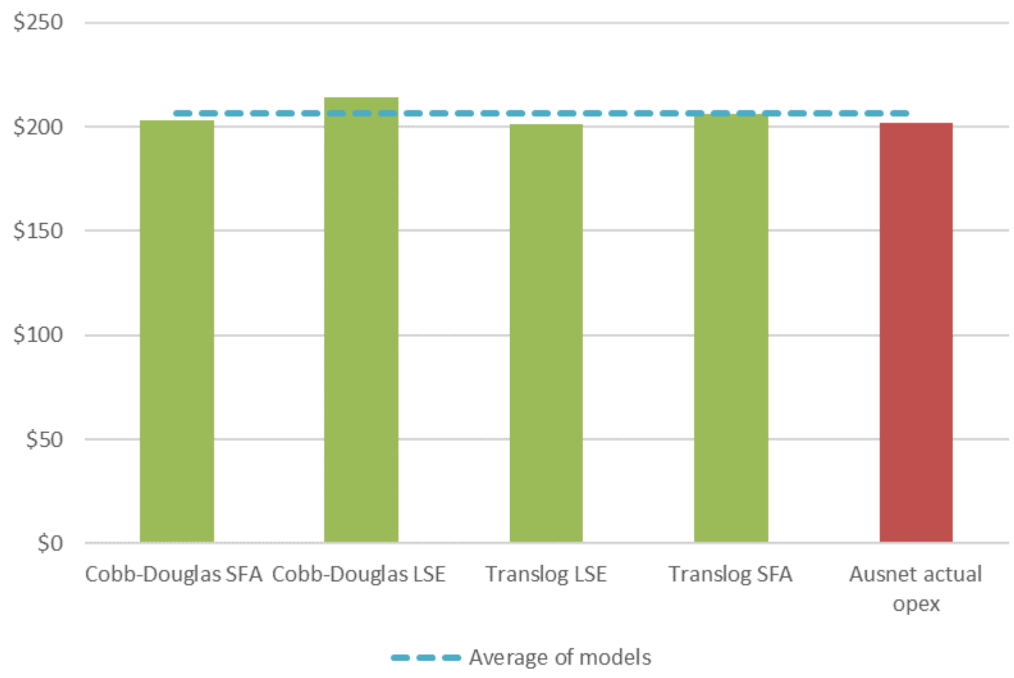
We adjust the benchmark comparison point for material differences in OEFs between the business and the benchmark comparators that are not already captured in the modelling (discussed further below). The benchmark comparator businesses are those businesses that have an average efficiency score above the 0.75 benchmark comparison score. (For both the 2006–19 and 2012–19 benchmarking periods, there are five businesses with average efficiency scores at or above 0.75, namely Powercor, CitiPower, United Energy, SA Power Networks and TasNetworks).

Where the business' efficiency score derived from an applicable model is below the adjusted benchmark comparison point, we adjust its period-average network services opex (established in the first step) down by the difference between the adjusted comparison point and the efficiency score. This results in an estimate of period-average network services opex that we consider is not materially inefficient.

This period-average network services opex estimate is then trended forward from the midpoint of the period to the base year to account for the rate of change. This results in a conservative estimate of efficient network services opex in the base year, which is compared against actual base year network services opex. This process is repeated for each econometric model, resulting in a different estimate for each.

The results of this analysis for AusNet Services are set out in Figure 6.8 for the 2006–19 period and in Figure 6.9 for the 2012–19 period using results from the *2020 Annual Benchmarking Report*. In Figure 6.8, our estimates of efficient network services opex (which includes adjustment for OEFs) in the base year using our econometric models over the 2006–19 period (as described above) are shown in green (with an average of $206.2 million ($2020–21)), while AusNet Services' actual network services opex in the base year of 2018 is shown in red ($201.7 million, ($2020–21)). The average of our efficient estimates (the blue dashed line) is materially ($4.6 million ($2020–21)) above AusNet Services' actual network services opex.

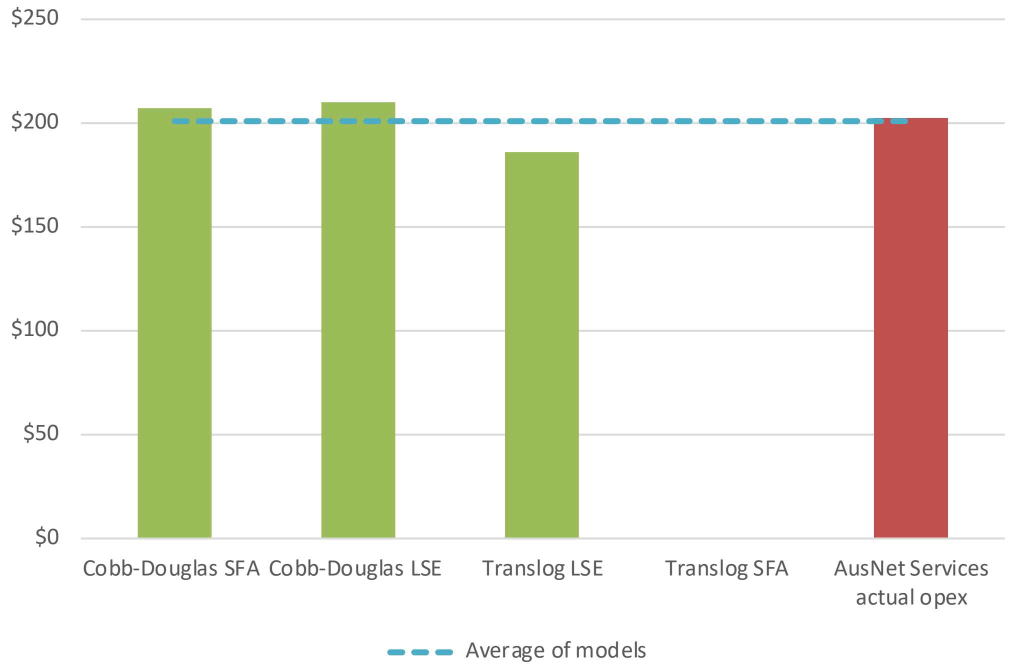
Figure 6.8 Estimates of efficient network services opex using data over the 2006–19 period ($ million, 2020–21)



Source: Economic Insights, *Benchmarking results for the AER – Distribution*, October 2020; AER analysis.

Similarly, in Figure 6.9 our estimates of efficient network services opex (which includes adjustment for OEFs) in the base year using our econometric models over the 2012–19 period are shown in green (with an average of $200.4 million ($2020–21)), while AusNet Services' actual network services opex in the base year of 2018 is again shown in red ($201.7 million ($2020–21)). Our average estimate (the blue dashed line) is $1.2 million ($2020–21), or 0.6 per cent below AusNet Services' actual opex.

Figure 6.9 Estimates of efficient network services opex using data over the 2012–19 period ($ million, 2020–21)



Source: Economic Insights, *Benchmarking results for the AER – Distribution*, October 2020; AER analysis.

Note: We exclude the efficiency score for the SFA TLG model for AusNet Services as it does not satisfy the monotonicity requirement (as discussed above). See Economic Insights, *Benchmarking results for the AER – Distribution*, October 2020, p. 13.

Across the two periods, the average estimate of efficient network services opex for AusNet Services in its base year is $1.7 million ($2020–21) or 0.8 per cent higher than AusNet Services' actual network services opex. This is an update from the draft decision, where the difference was $8.5 million ($2020–21) and 4.2 per cent. The change from the draft decision is due to a number of factors as mentioned throughout this section (e.g. updating to use results from the *2020 Annual Benchmarking Report*, the use of an OEF for capitalisation). As also discussed above, we have not used the SFA TLG model's estimate of efficient opex for AusNet Services as its results do not satisfy our key property of monotonicity – in the draft decision this model's estimate for efficient opex was similar but slightly below AusNet Services' actual opex.

In light of this evidence, on balance we consider that AusNet Services remains relatively efficient (or within the bounds of not materially inefficient). However, a continuation of a declining trend in relation to AusNet Services' efficiency (including its relative efficiency compared to other businesses that are improving) over the 2021–26 regulatory control period would be of concern when assessing its efficiency in setting base opex for the following regulatory control period.

Operating Environment Factors

Distribution businesses do not all operate under exactly the same operating environments. Our economic benchmarking techniques account for differences in operating environments to a significant degree, including the scope of services provided, the share of undergrounding and network densities. However, our benchmarking models do not directly account for all factors, such as differences in legislative or regulatory obligations, climate and geography.

Given this, we also consider OEFs as a part of our benchmarking analysis. This enables us to assess the efficiency of a distribution business' operations on a like-for-like basis to inform our assessment of whether its base year opex is efficient or materially inefficient. We do this by quantifying the material OEFs to adjust the benchmark comparison point (upwards for negative OEFs, downwards for positive OEFs) to account for the operating environment of the distribution business we are assessing (see Box 1). This adjusted comparison point is then compared to the business' efficiency score (from the benchmarking models), allowing us to account for potential cost differences due to material OEFs between the business and the benchmark comparison businesses. More detail on the mechanics of our approach is contained in past decisions.[57]

Based on a 2018 review carried out by our consultant Sapere-Merz, we have identified a limited number of OEFs that materially affect the relative opex of each business in the NEM. Sapere-Merz consulted with stakeholders, including the electricity network businesses in undertaking this review.[58]

The material OEFs Sapere-Merz identified are:

1. The higher operating costs of maintaining sub-transmission assets.
2. Differences in vegetation management requirements.
3. Jurisdictional taxes and levies.
4. The costs of planning for, and responding to, cyclones.
5. Backyard reticulation (in the ACT only).
6. Termite exposure.

Consistent with the draft decision, we have calculated the adjustments for each of these OEFs for AusNet Services. Since the draft decision, these adjustments have been updated for an additional year of data and the results of the *2020 Annual Benchmarking Report.* The results from the 2020 report impact the composition of the

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[57] AER*, Preliminary Decision, Ergon Energy determination 2015–20, Attachment 7 – Operating Expenditure,* April 2015, pp. 93–138; AER, *Draft Decision, Ausgrid Distribution determination 2019–24, Attachment 6 - Operating Expenditure,* November 2018, pp. 31–33; AER, *Draft Decision, Endeavour Energy Distribution determination 2019–24, Attachment 6 - Operating Expenditure,* November 2018, pp. 27–29.

[58] Sapere Research Group and Merz Consulting*, Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018.

comparator businesses[59] (with the addition of TasNetworks) and the efficient base opex for each business against which the cost of the OEF is compared to derive a percentage impact.[60] As discussed further below, we have also now included an OEF adjustment for capitalisation practices.

Table 6.4 shows our calculated OEFs for AusNet Services for the two benchmarking periods that are incorporated into the analysis shown in Figure 6.8 and Figure 6.9.[61]

Table 6.4 OEF adjustments for AusNet Services, per cent

	2006–19 period	2012–19 period
Sub-transmission (Licence conditions)	–0.2	0.1
Vegetation management (bushfire)	4.0	6.2
Taxes and levies	–1.5	–1.4
Termite exposure	0.1	0.1
Capitalisation	–0.8	–1.9
Total	1.6	3.1

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2020; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER analysis.

These results indicate that AusNet Services incurs net cost disadvantages (1.6 per cent and 3.1 per cent over the two benchmarking periods, respectively) relative to the comparator benchmark businesses. That is, relative to the benchmark comparator businesses AusNet Services incurs more costs given its operating environment. As per our standard approach, we reduce our benchmark comparator point of 0.75 to account for these cost disadvantages. The most material of these adjustments are discussed below.

OEF adjustment for vegetation management

The OEF for vegetation management (bushfire) exists to account for the differences in opex between distribution businesses due to differences in bushfire risk for clearing vegetation, in this case between AusNet Services and the comparator networks.[62]

59 The OEF adjustments are calculated using the customer-number weighted average of the comparator businesses as the reference point.

60 The OEF estimates in percentage terms are calculated by dividing the cost of the OEF by historical opex that is efficiency-adjusted using the opex efficiency scores.

61 The spreadsheets used to calculate these adjustments are published along with this decision.

62 In past decisions, we have also calculated a second vegetation management OEF, termed division of responsibility, in relation to the cost disadvantage in the scale of vegetation management responsibility compared to the benchmark comparator businesses in Victoria and South Australia. This was because in Queensland distribution businesses are responsible for vegetation clearance from all network assets, whereas in Victoria and South Australia, other parties such as councils, landowners and roads authorities are responsible for some

Consistent with the draft decision, we have applied the approach that we recently applied in our Ergon Energy determination, which was a re-application of the approach used in our Queensland 2015 decisions.[63] This approach calculates the vegetation management OEF for the relevant business by quantifying the cost impact of vegetation management regulations introduced in Victoria after the 2009 Black Saturday bushfires. The increased opex expected to be incurred as a result of the new regulations is used as a proxy for the differences in costs of managing bushfire risks in Victoria compared to other states. As a Victorian business, AusNet Services faced these additional vegetation management obligations and costs, and being a more rural business it is relatively more affected by bushfire risk obligations, which is reflected in the positive OEF adjustments shown in Table 6.4.[64]

OEF adjustment for capitalisation

Consistent with our final decision for Jemena,[65] we have included an OEF adjustment to account for AusNet Services' capitalisation practices being materially, although not substantially, different to the comparator businesses. Consistent with past decisions,[66] we have characterised capitalisation as an OEF in that while it is somewhat under managerial discretion, this factor is unrelated to efficiency. In addition, we do not consider that capitalisation practices are sufficiently accounted for elsewhere (i.e. directly in the data adjustments, modelling, or other OEF adjustments). For the purposes of our alternative estimate in this decision, and consistent with the method adopted for the Jemena final decision, we have applied an adjustment to recognise differences in AusNet Services' capitalisation practices compared to the comparator businesses. We used two ratios (opex/totex and opex/total cost) to inform this adjustment but note that the magnitude of our alternative estimate, and our final decision, does not change using an alternative method incorporating a third ratio (opex/total inputs).

We consider this approach fit for purpose in the context of AusNet Services' circumstances and for this final decision. However, we consider that the optimal method of identifying and adjusting for material difference in capitalisation between distribution businesses is an area of ongoing work and is an issue that we intend to explore further in the context of the *2021 Annual Benchmarking Report*.

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vegetation clearance. See AER, *Draft decision, Ergon Energy distribution determination 2020–21 to 2024–25 Attachment 6*, October 2019, pp. 83–85. Given AusNet Services is a Victorian network, its cost advantage/disadvantage for this OEF under our calculation method is zero.

63 AER*, Preliminary Decision, Ergon Energy determination 2015−16 to 2019−20, Attachment 7 − Operating Expenditure,* April 2015, p. 200; AER*, Final decision, Ergon Energy distribution determination 2020 to 25 Attachment 6, Operating expenditure,* June 2020, pp. 41–44.

64 More details of how this OEF adjustment are calculated is shown in the calculation spreadsheet, which we have published along with this decision.

65 AER, *Final Decision, Jemena 2021–26, Attachment 6 Operating expenditure,* April 2021, section 6.4.1.2; Appendix C.

66 AER*, Final Decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 7 - Operating expenditure,* April 2015, pp. 180–182, 193–196.

Following past decisions, we have used the term capitalisation practices to encompass two broad types of capitalisation undertaken by distribution businesses:

- capitalisation policy, i.e. a business' reporting/classification of expenditure as opex or capex, (e.g. expensing/capitalising overheads) including under a cost allocation method (CAM)[67]
- opex/capital trade-offs, i.e. a business' utilisation of opex versus capital inputs.

We observe some degree of variation among businesses in their capitalisation practices. The mix of opex and capital to produce outputs will be particular to each business, and there is some flexibility in capitalisation policy.[68] As noted above, benchmarking relies on like-with-like comparability. We recognised at the start of our economic benchmarking programme in 2014, that differences between businesses in terms of capitalisation potentially reduces comparability. For example, without broadly consistent capitalisation practices, a low opex efficiency score could penalise a business with a policy to expense all corporate overheads. We considered that the businesses' CAMs/capitalisation policies applying in 2014 (including Evoenergy's revised CAM) were broadly consistent.[69] We then 'froze' the CAMs as at 2014 for benchmarking purposes to minimise the scope for businesses to game the benchmarking by reallocating costs between opex and capex.[70]

AusNet Services submitted in its initial proposal that the capitalisation approach used for benchmarking will have a significant bearing on businesses' opex efficiency scores.[71] In the draft decision, we noted while capitalisation practices could potentially be impacting on our opex benchmarking scores, we did not consider this factor likely to be having a material impact, either positive or negative, on AusNet Services' opex benchmarking scores. On the indicators we examined, we considered that there was not strong evidence that AusNet Services' benchmarking score was being unduly impacted one way or the other by capitalisation practices. We stated that this issue was an area of ongoing work and sought feedback to inform the final decision.[72]

AusNet Services' revised proposal focused on the issue of different capitalisation practices and their impact on opex benchmarking efficiency scores. While AusNet Services welcomed the AER's measures to investigate differences in cost

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67 Businesses do not need to specify their capitalisation policies as a part of the CAMs submitted to the AER, although some businesses have included these in their CAMs.

68 For example, we know that, under their revised CAMs, CitiPower, Powercor and United Energy fully expense their corporate overheads, while other businesses do not. The extent of these differences is limited by some statutory reporting requirements e.g.in relation to expensing or capitalising certain costs.

69 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Annual Benchmarking Report,* 5 September 2019, pp. 3-4.

70 Where a business has subsequently changed its CAM, we ask that it continue to provide network services opex annually as if the 2014 CAM still applied.

71 AusNet Services*, Revised regulatory proposal 2022–26, Part III*, January 2020, p. 140.

72 AER, *Draft Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 36.

allocation and capitalisation approaches, it continued to advocate for the AER developing a uniform approach to assessing networks' capitalisation policies.[73]

AusNet Services maintained that benchmarking results change significantly depending on which capitalisation approach is used for benchmarking purposes (2014 CAMs or current CAMs). It presented analysis in its revised proposal which showed that the benchmarking results change significantly depending on which capitalisation approach is used. In particular, when Powercor and CitiPower's opex under its current CAMs is used, Powercor's performance decreased, CitiPower's ranking dropped from second to ninth position, and the overall industry productivity converged.[74]

In terms of other stakeholders, Ausgrid also submitted that the AER's current benchmarking approach does not do enough to adjust for differences in capitalisation policies.[75] It argued that using the 2014 CAMs for benchmarking opex artificially lifts Powercor and CitiPower's efficiency scores, and presented analysis which showed that these businesses' opex MPFP efficiency scores are significantly higher under their 2014 frozen CAMs compared to the current CAMs. Ausgrid considered the continued use of the frozen 2014 CAMs could be misleading and skews the benchmarking results, given that the actual level of opex these businesses spend under their current approved CAMs is much higher. It also submitted that the comparison point for a business' opex/totex ratio should be the frontier business' (Powercor's) opex/totex ratio.

Based on our further review of a range of qualitative and quantitative evidence, we now consider that there is sufficient evidence of capitalisation practices being materially although not substantially different between AusNet Services and the comparator businesses. This is a firmer conclusion than reached in the draft decision (and the *2020 Annual Benchmarking Report*) and reflects our further review of the issue.

Qualitatively, we have observed in the context of the AER's role in approving businesses' CAMs that there is variation in the manner in which businesses allocate and capitalise shared costs. For example, some distribution businesses (e.g. CitiPower, Powercor, Ergon Energy, and Jemena for the 2021–26 regulatory control period) have changed their capitalisation policy to expense more corporate (or all) overheads through a change in their CAM.

Quantitatively, for the purpose of this final decision we now consider that there is a material, although not substantial difference between AusNet Services' and the comparator businesses' capitalisation practices, and that that these differences have a material impact on its opex benchmarking scores. We have formed this view with particular regard to:

73 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, pp. 96–97.

74 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, pp. 96–97.

75 Ausgrid, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 4–8.

- The sensitivity of reported opex and associated opex benchmarking scores under alternative capitalisation policies
- AusNet Services' opex/capital ratios relative to the comparators, and a further assessment of the advantages and disadvantages of the three types of ratio we have identified.

In relation to the first factor, results of our modelling indicate that reported opex and the opex benchmarking scores are sensitive to the capitalisation policy in place. To explore this question, we recast the historical opex series on the basis of the current CAMs that businesses have in place (backcast to 2006) and ran our econometric cost models using this series (instead of the frozen 2014 CAM opex series). Given the current CAMs incorporate a change in capitalisation policy for three businesses (Powercor, CitiPower, and Ergon Energy), this analysis provides an insight into the impact of varying capitalisation practices on opex and opex benchmarking scores. While we do not consider we can rely on the current CAM efficiency scores to replace the 2014 CAM scores, or for deriving an OEF adjustment (as explained in our final decision for Jemena[76]), the change in the benchmarking efficiency scores indicates their sensitivity to capitalisation change and/or differences.

As an example to indicate this sensitivity, while AusNet Services' opex is the same under the 2014 and current CAMs (as it has not changed its CAM), AusNet Services' opex econometric efficiency scores under the current CAMs are 17 per cent higher than under the 2014 CAMs. This change in AusNet Services' score reflects the increase in the opex of the benchmark comparators (CitiPower and Powercor) under their revised CAMs.

In relation to the second factor, we continue to consider that opex/capital ratios are able to capture net capitalisation practices, irrespective of specific sources e.g. capitalisation/expensing of overheads, preferences for opex over capex. All else equal, a higher (lower) opex/capital ratio indicates a relatively greater (lesser) use of opex relative to capital inputs. As set out in the draft decision, we consider there are three types of opex/capital ratios that are informative indicators of businesses' capitalisation practices, with all measured as average ratios over the full (2006–19) and short (2012–19) benchmarking periods.[77]

- Opex/totex
- Opex/total cost where total costs is opex + capital costs (the latter measured by the annual user cost of capital (AUC))
- Opex/total inputs.

Since the draft decision, we have further examined the merits of the three ratios, and consider that they provide evidence that AusNet Services' capitalisation practices are

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76 See AER, *Final Decision, Jemena 2021–26, Attachment 6 Operating expenditure*, April 2021, section 6.4.1.2 and Appendix C.

77 AER, *Draft Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 36–40.

materially, although not substantially, different to the comparator businesses. In particular, we consider that, on balance, AusNet Services reports/utilises somewhat less opex than capital in delivering outputs compared to the comparator businesses. This is indicated by AusNet Services' opex/capital ratios being, approximately 1-2 per cent below the comparator-average ratios depending on the method used to weight these ratios (as outlined below).

We continue to consider that each ratio has strengths and limitations, and so we have had regard to all three ratios as indicators of variations in capitalisation practices. Our views around each of these ratios, and their strengths and weaknesses, is set out in Appendix A.

In terms of calculating the OEF adjustment, for the purposes of this final decision we have derived this based on the percentage divergence of AusNet Services' opex/totex and opex/total cost ratios relative to the respective comparator-average ratios. Specifically, we have calculated the OEF adjustment for the two benchmarking periods (2006–19 and 2012–19) by taking the midpoint of the percentage differences between AusNet Services' opex/totex and opex/total cost ratios and the respective customer-weighted comparator-average ratios (all measured as average ratios over the two benchmarking periods). This calculation method is consistent with our standard OEF adjustment calculation method of calculating the percentage impact of the OEF on a business' opex relative to the comparator-average impact. This approach incorporates two different measures of opex/capital mix, recognising that each has advantages and disadvantages, as discussed in Appendix A.

For this final decision, we also examined a range of alternative methods of calculating the OEF adjustment for capitalisation for this decision, including those put forward by Jemena, as discussed in Appendix D of Jemena's final decision. We consider that a feasible alternative method would incorporate the opex/total inputs ratio, which was the third ratio that we put forward in the draft decision.[78] Specifically, we considered an OEF adjustment method based on the weighted average of the opex/totex (0.5 weight), opex/total cost (0.25) and opex/total inputs (0.25) ratios. We adopted this particular weighting to reflect that the opex/total cost and opex/total inputs ratios both incorporate a measure of the capital stock, set against the opex/totex ratio which is expenditure-based. We note that we have some concerns with using an index-based ratio in this manner, for technical reasons explained in Appendix A. We will further review the use of the opex/total input ratio within our broader review of capitalisation in the *2021 Annual Benchmarking Report*. We note that the broad magnitude of our alternative estimate, and our final overall decision to accept AusNet Services' opex proposal, does not change under this alternative method.

In relation to AusNet Services and stakeholder views, we share AusNet Services' and other stakeholders' view that opex efficiency scores are sensitive to the CAM and associated capitalisation policy. This is to be expected, given the large impact of

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78 AER, *Draft Decision, Jemena 2021–26, Attachment 6 Operating expenditure*, September 2020, p. 93.

CitiPower/Powercor's capitalisation policy change on their level of opex and the significance of opex as a variable in opex benchmarking. However, we consider a fresh analysis of the difference between a given business and the comparator businesses under any alternative set of CAMs is still required. This is because whether and to what extent the business' capitalisation practices differ from the comparator businesses under a given CAM still needs to be taken into account. A further concern we have with relying on the current CAMs for deriving an OEF adjustment is that the current CAMs may reflect some degree of endogenous response to our benchmarking, rather than reflecting only updates to costing approaches or corporate structures.

We do not agree with Ausgrid's submission on the comparator point.[79] We use 0.75 rather than 1.0 (or the frontier business) as the comparator point for comparing capitalisation practices. This is to be consistent with our standard approach to OEF adjustment calculation.

Taxes and levies

In its initial proposal, AusNet Services submitted that its OEF relating to tax and levies needed to be re-estimated, on the basis that there has been a recent change to the classification of its opex for benchmarking to include tax and levies.[80] In the draft decision, we noted we would welcome further details and any updated data from AusNet Services.

AusNet Services did not provide this additional information in its revised proposal. We understand that this change refers to a change in classification (i.e. the inclusion of AusNet Services' taxes and levies into network services opex from 2016), rather than a change in underlying taxes and levies payments. For consistency with how we have calculated the other OEF adjustments for other businesses, we have therefore relied on the information collected from AusNet Services and other businesses through the 2018 OEF review and reflected in the OEF estimates above. However, we note that using the tax and levies OEF adjustment in Table 6.4 that is based on the information available to us, our finding is that AusNet Services' base year opex is relatively efficient. We do not consider this conclusion would change based on an updated tax and levies OEF adjustment if we considered there was a case for this and the data was available.

6.4.1.3 Final year increment

Our standard practice to calculate final year opex is to add the difference between the opex forecast for the final year of the preceding regulatory control period and the opex forecast for the base year to the amount of actual opex in the base year.[81] As a result of the six month extension to the current regulatory control period, we have updated

[79] Ausgrid, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 7.

[80] AusNet Services*, Revised regulatory proposal 2022–26, Part III,* January 2020, pp. 138–140.

[81] AER, *Expenditure forecast assessment guidelines for electricity distribution,* November 2013. pp. 22–23.

our final year increment calculation by replacing the opex forecast for the final year of the preceding regulatory control period with the annualised half year 2021 forecast.

By forecasting opex in this way, the opex forecast assumes AusNet Services makes no efficiency gains between the base year and the final year. This allows AusNet Services to retain the efficiency gains it makes in the final year through the opex forecast.[82] This is consistent with the decision to apply the EBSS during the 2016–20 regulatory control period.[83]

6.4.1.4 Base adjustments

ESV levy

Our final decision is to remove ESV levies from base opex in our alternative estimate. This is because they will be recovered via the price control mechanism over the 2021–26 regulatory control period following our decision on 19 March 2021 to approve the ESV levy as a jurisdictional scheme.[84] This is consistent with AusNet Services' revised opex proposal, which removed ESV levy costs from base opex, although it proposed that they be recovered via an annual B factor adjustment in the price control formula.[85]

Table 6.5 ESV levy ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	–2.2	–2.2	–2.2	–2.2	–2.2	–11.2
AER final decision	–2.2	–2.2	–2.2	–2.2	–2.2	–11.2
Difference	–	–	–	–	–	–

Source: AusNet Services, information request #089, March 2021.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

AusNet Services' initial proposal also removed ESV levies from base opex and sought to recover these costs through an annual L factor adjustment in the price control mechanism over the 2021–26 regulatory control. Our draft decision did not include this base adjustment in our alternative estimate for the following reasons:[86]

- base opex reflects the cost of meeting existing regulatory obligations, including the obligation to pay the ESV levy

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82 AER, *Expenditure forecast assessment guidelines for electricity distribution*, November 2013, pp. 22–23.

83 AER, *AusNet Services distribution determination 2016 to 2020, Final decision, Attachment 9, Efficiency Benefit Sharing Scheme*, May 2016, pp. 6–7.

84 AER, *Determination on CPU jurisdictional scheme request*, March 2021.

85 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 77.

86 AER, *Draft Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 41–42.

- changes in specific costs should be managed within:
  - the existing base opex as the cost of other projects or programs decline. A rise in a single cost category is not sufficient to justify a step change, and/or
  - the rate of change forecast which escalates base opex to capture real increases in input prices and output growth (net of productivity growth).

In its revised proposal, AusNet Services maintained its position to recover the ESV levies through the price control.[87]

The VCO's submission was supportive of our draft decision and considered the ESV levy increases should be absorbed by the distribution businesses.[88] However, ECA's consultant, Spencer&Co supported moving the ESV levy into the price control mechanism, on the basis that these fees are outside the control of the business.[89]

On 25 February 2021, CitiPower, Powercor and United Energy submitted an application to request that the AER determine the ESV levy is a jurisdictional scheme.[90] We considered that the ESV levy meets the jurisdictional scheme criteria, and we determined that ESV levy is a jurisdictional scheme.[91] Further details are in our decision.[92] In this distribution determination, we have also made a decision on how AusNet Services, and the other Victorian businesses, are to report to the AER on its recovery of the jurisdictional scheme amounts for the scheme and on the adjustments to be made to pricing proposals to account for over and under recovery.[93] As a result, the ESV levy becomes an approved jurisdictional scheme for AusNet Services. The scheme amounts are recovered via the price control mechanism and therefore we have removed such costs from total opex in our alternative estimate.

We note that while the ESV levy meets the jurisdictional scheme criteria, and have not included these costs in our alternative estimate, we consider from a policy perspective there is a strong case for such costs to remain in base opex. The reasons for this are:

- While they are costs which may be outside the control of the distribution businesses, neither opex nor the EBSS within our framework distinguishes between controllable and uncontrollable costs. As stated in our explanatory statement for the EBSS[94] to do so would weaken the incentive framework and there is no compelling reason to share the cost of uncontrollable events between

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87 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 77.

88 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals*, January 2021, p. 55.

89 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18.

90 CitiPower. Powercor and United Energy, *Jurisdictional scheme determination request,* February 2021.

91 NER, cll. 6.18.7A(n) and 6.18.7A(x).

92 AER*, Determination on CPU jurisdictional scheme request*, March 2021.

93 NER, cl, 6.12.1(20) and AER, *Final decision, AusNet Services distribution determination 2021–26 – Overview, April* 2021, Appendix A; AER, *Final decision, AusNet Services distribution determination 2021–26, Attachment 14 Control mechanisms,* April 2021, Appendix D.

94 AER, *Explanatory statement – efficiency benefit sharing scheme,* November 2013, pp. 19–21.

consumers and the businesses differently to all other costs they face. Uncontrollable costs present both upside and downside risks for businesses, with any material risks able to be managed via pass-through events and contingent projects. So while levies and licence fee costs may be largely out of the control of businesses, we consider this should not preclude them from being included in our total opex forecast and subject to the EBSS.

- While we recognise that licence fee and levy costs may experience changes, our top down approach seeks to set a total opex forecast. As explained in our assessment approach in the draft decision[95] 'even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.'
- Increasing the number of items included in the price control mechanism makes it difficult for consumers to know how much tariffs will change year to year if they are subject to numerous adjustments.

AusNet Services' revised proposal also sought to recover changes in expected AEMO fees through the price control mechanism for similar reasons it outlined in its revised proposal for ESV levies.[96]

On 26 March 2021, AEMO published its final report on Electricity Fee Structure which determined that distributors will not be charged participant fees for the next fee period.[97] As a result of AEMO's final report there is no need to include these fees in opex or the price control formula.

Metering systems reallocation

Our final decision is to include a base adjustment to reallocate $8.1 million ($2020–21) of IT opex for metering services to standard control services (from alternative control services) in our alternative estimate.[98] This is consistent with our draft decision.

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95 AER*, Draft Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure*, September 2020, p. 16.

96 AusNet Services, *Revised Regulatory Proposal 2021–26,* December 2020, p. 78.

97 AEMO, *Final Report and Determination, Electricity Fee Structures,* March 2021, pp. 5, 26.

98 Standard control services are those relating to the distribution system where as alternative control services are specific services that are only requested by certain customers, such as metering.

Table 6.6 Metering reallocation ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	2.5	2.5	2.5	2.5	2.5	12.3
AER final decision	1.6	1.6	1.6	1.6	1.6	8.1
Difference	–0.8	–0.8	–0.8	–0.8	–0.8	–4.2

Source: AusNet Services, *Revised Regulatory proposa. 2021–26 – Opex model, December 2020*; AER analysis.

Note: Numbers may not add up to total due to rounding.

In our draft decision, we included a base adjustment to reallocate $7.8 million ($2020–21) of IT opex for metering services to standard control services in our alternative estimate. This was a downward adjustment from AusNet Services' proposed $29.4 million ($2021–21) reallocation.[99] We applied the following reallocations:[100]

- We substituted our 6 per cent standard control service / 94 per cent alternative control service cost allocation approach for the 50 per cent standard control service / 50 per cent alternative control service allocation proposed by AusNet Services. Our allocation was based on:
    - power quality data where we considered it could be used as a reasonable cost allocator. This allocation was based on a review by our Technical Advisory Group which considered it reasonable to obtain power quality data from 1 per cent of meters relative to AusNet Services' assumption of collecting power quality data from 85 per cent of meters.
    - an equal cost allocation split across standard control services and alternative control services where we considered there was insufficient information to establish a causal method of allocation using the power quality data provided.

In its revised proposal, AusNet Services submitted the following reallocations for these components (which are different to our draft decision reallocation of 6 per cent standard control services / 94 per cent alternative control services):[101]

- 20 per cent standard control service / 80 per cent alternative control services for Mesh UIQ and SIQ licensing. AusNet Services based the causal allocation on the annual license fees it pays for the UIQ and SIQ applications. The license fees are based on the quantity of meters that data is collected from. For the SIQ license, this is based on collecting power quality data from 100 per cent of meters.[102]

99 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020 p. 42.

100 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020 pp.43–44.

101 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 179.

102 AusNet Services, *Information request 090,* January 28.

- 36 per cent standard control services / 64 per cent alternative control services for the Telstra Mesh 'Backhaul'. To derive this proposed reallocation, AusNet Services continued to assume a volume of power quality which is equivalent to collecting data from 85 per cent of meters. To adjust for the smaller packet size of power quality data collected, AusNet Services applied a 10 per cent estimate to the volume of power quality to justify its proposed reallocation.[103]

ECA had no objection to the reallocation of metering costs to standard control services as it considered it makes little difference to customers where there is no metering competition.[104]

Consistent with our draft decision, for the Mesh UIQ/ SIQ licensing component, we have retained a 6 per cent standard control / 94 per cent alternative control service cost allocation. AusNet Services submitted that it collects 'PQ data from 100% of [our] meters through SIQ and our license is based on 100% of our meters collecting PQ data.'[105] We do not consider the costs of collecting power quality data from 100 per cent of meters outweighs the benefits passed on to consumers from this practice. Consistent with our draft decision, we consider it is more reasonable to obtain power quality data from 1 per cent of meters. This is discussed in more detail in Attachment 16 – Alternative control services.

Also consistent with our draft decision, our final decision is to apply a 6 per cent standard control services / 94 per cent alternative control service cost allocation for the Telstra Mesh 'Backhaul' component in determining our alternative estimate. We do not consider AusNet Services' proposed reallocation of 36 per cent / 64 per cent is efficient on the basis that AusNet Services has not provided justification for the volume of power quality data it proposes to collect from meters. While AusNet Services proposed to adjust its volume power quality data to account for the smaller packet size, the volume proposed is still significantly larger than we consider is reasonable.

We have continued to treat this as a base adjustment, consistent with our draft decision and have updated the costs to account for updated inflation forecasts for the final decision.

Lease capitalisation

Consistent with our draft decision,[106] our final decision is to include a base adjustment of –$21.8 million ($2020–21) as a non-recurrent efficiency adjustment in our alternative estimate to reflect new reporting obligations associated with leases under revised Australian Accounting standard AASB 16.

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103 AusNet Services, *Information request 066 – Q2*, January 28, p. 2.

104 Spencer&Co, Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals,* January 2021, p 18.

105 AusNet Services, *Information request 090,* February 23.

106 AER, *Draft decision*, *AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 40–41.

Table 6.6 Lease capitalisation ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	–4.4	–4.4	–4.4	–4.4	–4.4	–21.8
AER final decision	–4.4	–4.4	–4.4	–4.4	–4.4	–21.8
Difference	–	–	–	–	–	–

Source: AusNet Services, information request #089, March 2021; AER analysis.

Note: Numbers may not add up to totals due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we accepted that regulatory accounts should be prepared in accordance with the applicable accounting standards, noting that from 1 April 2019 AusNet Services proposed to treat all existing property leases as capex consistent with AASB 16. Our reasoning for treating the new reporting obligations as a non-recurrent efficiency adjustment is outlined in AusNet Services' EBSS draft decision.[107] We also noted that this treatment was consistent with AusNet Services CAM and had a neutral impact on consumers as AusNet Services will only be recovering the net present value of the opex lease payments via our capex forecast.[108]

AusNet Services' revised proposal accepted our draft decision.[109] Therefore, we have included this base adjustment in our alternative estimate for the final decision.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[110]

In its revised proposal AusNet Services applied our standard approach to forecasting the rate of change. Specifically it:

- **Output growth:** adopted the output weights, measures and values we used in our draft decision.[111]

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107 AER, *Draft decision, AusNet Services distribution determination 2021–26 - Attachment 8 - Efficiency benefit sharing scheme,* September 2020, pp. 11–12.

108 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020, p. 41.

109 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 74.

110 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 23–24.

111 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 81, AusNet Services, *information request #089,* March 2021.

- **Price growth:** adopted our input price weightings of 59.2 per cent labour and 40.8 per cent non-labour and an average of Wage Price Index (WPI) price growth forecasts from Deloitte and BIS Oxford Economics for labour price growth.[112]
- **Productivity growth:** adopted our productivity growth forecast of 0.5 per cent per year.[113]

The rate of change proposed by AusNet Services contributes $25.7 million ($2020–21), or 2.1 per cent, to AusNet Services' updated revised proposal total opex forecast of $1238.7 million ($2020–21). This equates to opex increasing on average by around 0.9 per cent each year in the next regulatory period.[114]

We have also included a rate of change that on average is around 0.9 per cent each year in the next regulatory period in our alternative estimate. We have set out in Table 6.8 AusNet Services' updated revised proposal and our alternative estimate for each component of the rate of change. We set out the reasons for our forecast below.

We received one submission from the VCO, relating to the rate of change. It generally supported our approach to forecast the rate of change in our draft decision, specifically how we accounted for the impact of COVID 19. The VCO stated that we should apply the same approach across all the Victorian businesses.[115] We have considered this submission in making our final decision.

Table 6.7 Forecast rate of change, per cent

	2021–22*	2022–23	2023–24	2024–25	2025–26
AusNet Services' proposal					
Price growth	0.5	0.3	0.4	0.6	0.8
Output growth	0.5	0.8	1.0	1.0	1.0
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	**0.6**	**0.6**	**0.9**	**1.1**	**1.3**
AER final decision					
Price growth	0.5	0.4	0.4	0.4	0.6
Output growth	0.5	0.8	1.1	1.0	1.0
Productivity growth	0.4	0.5	0.5	0.5	0.5

112 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 81; AusNet Services, *information request #089,* March 2021.

113 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 82; AusNet Services, *information request #089,* March 2021.

114 AusNet Services, *information request #089,* March 2021.

115 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals*, January 2021, p. 18, 52.

	2021–22*	2022–23	2023–24	2024–25	2025–26
Overall rate of change	**0.6**	**0.7**	**0.9**	**1.0**	**1.1**
Overall difference	**0.0**	**0.1**	**0.0**	**–0.1**	**–0.2**

* The rate of change for 2021–22 reflects nine months' worth of growth in price, output and productivity to account for the extension of the current regulatory control period by six months to transition the timing of the regulatory control period for Victorian electricity distribution networks from a calendar year basis to a financial year basis. We discussed the reasons for this in our draft decision which are summarised below.

Source: AusNet Services, *information request #089,* March 2021.; AER analysis.

Note: Numbers may not add up to totals due to rounding.

6.4.2.1 Forecast price growth

We have included forecast average annual real price growth of 0.4 per cent in our alternative opex estimate.[116] This compares to AusNet Services' proposed average annual price growth of 0.5 per cent.[117] This increases our alternative estimate of total opex by $14.1 million ($2020–21), instead of $14.2 million ($2020–21) as proposed by AusNet Services.

Our real price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- To forecast labour price growth we have used the forecast of growth in the WPI for the Victorian electricity, gas, water and waste services (utilities) industry. Specifically, we have used an average of forecasts from Deloitte and the BIS Oxford forecasts submitted by AusNet Services. In our draft decision we did not use the BIS Oxford forecasts submitted by AusNet Services with its initial proposal because we considered they did not account for the COVID–19 pandemic impact or the legislated changes to the superannuation guarantee.[118] The revised BIS Oxford forecasts submitted by AusNet Services now account for both of these issues.[119]
- Both we and AusNet Services applied a forecast non-labour real price growth rate of zero. [120] This is consistent with our draft decision and AusNet Services' initial proposal.
- We applied benchmark input price weights of 59.2 per cent and 40.8 per cent for labour and non-labour, respectively. These are the weights we use for our

116 Due to rounding this is lower than the average in Table 6.8.

117 AusNet Services, *information request #089,* March 2021.

118 AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 46–47.

119 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, pp. 71, 81.

120 AusNet Services, *information request #089,* March 2021..

econometric modelling in our annual benchmarking report.[121] This is also consistent with our draft decision and AusNet Services' revised proposals.[122]

Consequently, we and AusNet Services have applied the same approach to forecast price growth. The only differences between our real price growth forecasts and AusNet Services' is that we have:

- used more recent forecasts of WPI growth from Deloitte[123]
- adjusted BIS Oxford Economics' WPI growth forecast for 2021–22 to reflect the growth between the average WPI value for the first six months of calendar year 2021 and the average value for the 2021–22 financial year. This is to account for the shift from calendar years to financial years and is the same approach we adopted for the draft decision.[124]

6.4.2.2 Forecast output growth

We have included forecast average annual output growth of 0.9 per cent in our alternative opex forecast. This increases our alternative estimate of total opex by $27.0 million ($2020–21) instead of $26.4 million ($2020–21) as proposed by AusNet Services. The difference between us and AusNet Services is due to updates to output weights, which are discussed below.

In its revised proposal AusNet Services included an average annual output growth forecast of 0.9 per cent based on our standard approach to forecast output growth, and consistent with its initial proposal.[125]

In our draft decision we stated that we would update the output weights to reflect the results from all five of our economic benchmarking models in the *2020 Annual Benchmarking Report*, which we published in November 2020.[126]

For this final decision, we have used the updated weights derived from the *2020 Annual Benchmarking Report* to forecast our alternative estimate of forecast opex for this final decision. As set out below, in addition to updating these weights to reflect the results in the most recent benchmarking report, we have also considered the appropriate weights to use in response to feedback received as a part of the Victorian resets. In summary, we have forecast output growth by:

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[121] Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 8.

[122] AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, pp. 46–47; AusNet Services, *information request #089,* March 2021.

[123] Deloitte Access Economics, *Wage Price Index forecasts - Prepared for the Australian Energy Regulator,* Table vii, p. xiii, 1 April 2021. We have added increases to the superannuation guarantee of 0.5 per cent to Deloitte's forecast.

[124] AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 53.

[125] AusNet Services, *information request #089,* March 2021.

[126] AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 50.

- Calculating the growth rates for three outputs (customer numbers, circuit line length and ratcheted maximum demand). This is a change from our draft decision where we also used energy throughput. AusNet Services applied the output measures we used for our draft decision, including energy throughput.[127]
- Calculating four weighted average overall output growth rates for these three outputs using the output weights from four of the five models presented in our *2020 Annual Benchmarking Report* (see Table 6.9). For the reasons set out below, we did not use the opex MPFP model for this final decision. In contrast AusNet Services' updated revised proposal relied on all the five benchmarking models.
- For our Translog models, calculating the elasticities at the full sample mean. For our draft decisions we calculated the elasticities at the Australian sample mean, which is the approach AusNet Services also adopted in its revised proposal. We discuss the reasons for this change in approach below.
- Averaging the four model specific weighted overall output growth rates.

The output weights that we have used in our alternative estimate for the final decision are set out in Table 6.9.

Table 6.8 AER output weights, per cent

	Cobb-Douglas SFA	Cobb-Douglas LSE	Translog LSE	Translog SFA	Average	Draft decision average
Customer numbers	50.9	63.3	49.5	59.3	55.7	52.5
Circuit length	14.9	16.4	16.6	14.2	15.5	20.7
Ratcheted maximum demand	34.2	20.3	33.9	26.5	28.7	25.1
Energy throughput	–	–	–	–	–	1.7

Source: Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 21; AER, *Draft decision AusNet Services distribution determination 2021–26*, Attachment 6, Operating expenditure, September 2020, pp. 49–50.

Note Numbers may not add up to 100 per cent due to rounding. Energy throughput is only used in the opex MFPF model.

The difference between our output growth forecasts and AusNet Services' updated revised proposal is due to us:

[127] AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 49; AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 81.

- Updating output weights to reflect our 2020 annual benchmarking results as stated in the draft decision.[128]
- Not using the opex MPFP output weights and consequently not including energy throughput in forecasting our output growth (see below).
- Using output weights from the Translog opex cost function with data normalised by the full sample means (see below).

AusNet Services accepted our draft decision on the forecast growth of the individual output measures and we have maintained these in developing our alternative estimate.[129]

Exclusion of opex MPFP weights from our alternative output growth forecast

Our standard approach to forecast output growth has been to calculate the average output growth across all of the benchmarking models we have published in our most recent annual benchmarking report for the full benchmarking period. For our draft decision this was four econometric methods (two Cobb-Douglas (CD SFA and CD LSE) and two Translog (TLG SFA and TLG LSE)) and one using the opex partial productivity index number method (opex MPFP).[130] In its revised proposal as a part of the Victorian distribution resets Jemena and its consultant, CEPA, submitted that it was inappropriate to use the opex MPFP output weights for the purpose of trending opex forward because they reflect drivers of total cost, not the relationship between output and opex.[131] CitiPower, Powercor and United Energy also raised concerns with using the opex MPFP weights, although they did use them in their revised proposals.[132]

We agree that we should not include the opex MPFP weights in determining our forecast of output growth because they reflect drivers of, and relationship with total cost, not necessarily opex. This is consistent with Economic Insights' view.[133] Consequently, we have not used the output weights from this model or energy throughput as an output measure in this final decision (as the opex MPFP benchmarking is the only model that includes this output).

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128 AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 50.

129 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 81.

130 AER, *Draft decision AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure,* September 2020, p. 49–50.

131 CEPA, *AERs opex benchmarking a review of the impact of capitalisation and model reliability - 20201203 - Public,* December 2020, p. 27; Jemena, *Revised Regulatory Proposal – 2021–26 - Att 05-01 Operating Expenditure ,* December 2020, p. 26.

132 CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 122.

133 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report,* October 2020, p. 5.

Translog cost function weights

For this final decision, we have calculated the Translog elasticities at the full sample mean. In our draft decision, we used the output weights from the Translog opex cost function models with data normalised by the Australian sample mean. We adopted this approach in response to concerns raised by Frontier Economics in a report submitted with CitiPower's, Powercor's and United Energy's initial regulatory proposals.[134] This considered the elasticities should be evaluated at output levels that reflect the operating characteristics of Australian distributors.

Our consultant, Economic Insights agreed there was some merit in normalising output variables in the opex cost function database by the respective means of the Australian sample, rather than the means of the full sample as suggested by Frontier Economics.[135] However, in its 2020 Benchmarking Report, Economic Insights advised against making this change until there has been sufficient opportunity to review the performance of the Translog models. The inclusion of additional data from 2019 raised a number of monotonicity violation concerns with the Australian distributors.[136] We agree with this advice and we will continue to monitor the performance of our Translog cost function as part our ongoing benchmarking development.[137]

Jemena submitted in its revised proposal that we should adopt the output weights based on the full sample mean if we were to continue relying on the Translog models.[138] This is what we have done for this final decision.

6.4.2.3 Productivity growth

Consistent with our draft decision, we have forecast annual productivity growth of 0.5 per cent.[139] This reduces our alternative estimate of total opex by $15.0 million ($2020–21). AusNet Services also adopted a productivity growth forecast of 0.5 per cent per year in its revised proposal, consistent with our draft decision, which reduced its total opex forecast by $14.8 million ($2019–20).[140]

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134 Frontier Economics, *Review of econometric models used by the AER to estimate output growth - a report prepared for Citipower, Powercor and United Energy*, 5 December 2019, pp. 16–18.

135 Economic Insights, *Memorandum prepared for the AER on review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 20.

136 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report*, October 2020, p. 13.

137 For more detail about issues on the performance of the Translog cost function benchmarking models (in relation to monotonicity), see: Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report,* October 2020, p. 34.

138 Jemena, *Revised Regulatory Proposal – 2021–26 - Att 05-01 Operating Expenditure,* December 2020, p. 27.

139 AER, *Draft decision, AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure*, September 2020, p. 53.

140 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 82.

6.4.3 Step changes

In its revised proposal, AusNet Services:

- re-proposed three of the same step changes as in its initial proposal
- did not re-propose the opex step change for cyber security (noting that it would allocate all of the incremental cyber security costs to reach the required transmission standards to its transmission business)
- proposed two new step changes.[141]

Table 6.10 summarises the step changes AusNet Services included in its initial, revised and updated revised proposals as well as what we included in our alternative estimates for the draft and final decisions. In its updated revised proposal, AusNet Services' step changes totalled $55.2 million ($2020–21) as compared to the $20.6 million ($2020–21) included in its revised proposal. This update included a step change for insurance premiums of $45.1 million ($2020–21), which we considered should be recovered via a step change.

We have included $55.2 million ($2020–21) for five step changes in our alternative estimate for the final decision. We have examined each step change on its own merit and whether the proposal meets the intent of what step changes should reflect as set out in the Expenditure Forecast Assessment Guideline.[142] Noting that step changes should not double count cost increases compensated through the rate of change, we have included step changes in our alternative estimate for:

- Rapid Earth Fault Current Limiter (REFCL) testing and maintenance: $4.5 million ($2020–21)
- IT cloud: $2.6 million ($2020–21)
- new five minute meter requirements: $3.5 million ($2020–21)
- increasing insurance premiums: $45.1 million ($2020–21)
- a negative step change from the 2020 summer bushfires: $0.5 million ($2020–21).

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[141] AusNet Services, information request #089, March 2021; AusNet Services*, 2021–26 Revised regulatory proposal,* December 2020, pp. 87–90.

[142] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

Table 6.9 AusNet Services' step change proposals and our alternative estimates ($ million, 2020–21)

Step change	AusNet Services initial proposal	AER draft decision	AusNet Services revised proposal	AusNet Services updated revised proposal	AER alternative estimate for Final Decision	Difference
REFCL testing and maintenance	5.9	5.8	4.5	4.5	4.5	0.0
IT cloud	2.6	–	2.6	2.6	2.6	–
Cyber Security	4.6	–	–	–	–	–
5 minute meter data	3.6	3.5	3.5	3.5	3.5	–
Insurance premiums	–	–	10.5	45.1	45.1	–
Bushfire cost pass through	–	–	-0.5	-0.5	-0.5	0.0
Total step changes	16.7	9.3	20.6	55.2	55.2	0.0

Source: AusNet Services, *Regulatory proposal 2021–26 – Supporting document – Workbook 1 – Regulatory determination,* January 2020; AusNet Services, *information request #089,* March 2021.; AER, *Final Decision – AusNet Services distribution determination 2021–26 – Opex model, April* 2021; AER, *Draft Decision – AusNet Services distribution determination 2021–26 – Opex model,* September 2020; AER analysis.

Note: Numbers may not add up to total due to rounding. The difference is between AusNet Services' updated proposal and our final decision. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

The following sections sets out the reasons for our alternative estimate of each step change.

6.4.3.1 Rapid Earth Current Fault Limiters

Our final decision is to include a step change of $4.5 million ($2020–21) for annual REFCL testing and maintenance in our alternative estimate, which is lower than our draft decision ($5.8 million, $2020–21).

Table 6.10 REFCL testing and maintenance ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services revised proposal	1.3	0.5	1.2	0.8	0.8	4.5
AER final decision	1.3	0.5	1.2	0.8	0.8	4.5
Difference	–0.0	–0.0	–0.0	–0.0	–0.0	–0.0

Source: AusNet Services, *information request #089,* March 2021.: AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we included a step change of $5.8 million ($2020–21) for REFCL annual testing and maintenance in our alternative estimate but stated that we expected

AusNet Services to update this amount in its revised proposal. This update was to reflect the impact of any ESV amendment to its annual testing obligations and forecast inflation.

It its revised proposal AusNet Services included $4.5 million ($2020–21) and consistent with our request it accounted for the ESV's amendments to AusNet Services' annual testing obligations and updates in forecast inflation.[143] We have reviewed AusNet Services updated calculations and forecasts and are satisfied they are reasonable. As a result we have included $4.5 million in our alternative estimate.

6.4.3.2 IT cloud

Our final decision is to include a step change of $2.6 million ($2020–21) for an IT cloud step change in our alternative estimate. This is to recover cloud transition costs related to the roll out of a Customer Relationship Management IT system and Outage Management system to replace on-premises infrastructure. This differs from our draft decision to not include this step change in our alternative estimate.[144]

Table 6.11 IT cloud ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	0.5	0.5	0.5	0.5	0.5	2.6
AER final decision	0.5	0.5	0.5	0.5	0.5	2.6
Difference	–	–	–	–	–	–

Source: AusNet Services, *Revised regulatory proposal 2022–26 – Opex Model (2022-26)*, December 2020; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we did not include the proposed $2.6 million ($2020–21) costs in our alternative estimate. This was because taking into account our consultant EMCa's advice, we considered insufficient evidence had been provided to demonstrate a capex-opex substitution. Our draft decision noted that for us to accept a step change on the basis of a capex-opex trade-off criteria, we would need to be satisfied that the proposed expenditure is prudent and efficient through robust cost benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.[145]

[143] AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, pp. 84–85.

[144] AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020*,* p. *57*–59.

[145] AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020*,* pp. 58–59.

In its revised proposal[146] and responses to subsequent information requests, AusNet Services re-proposed this step change, submitting:

- Additional analysis undertaken to demonstrate the increased capex and program opex that would be incurred if the step change is not implemented. AusNet Services' further analysis demonstrated for the Customer Relationship Management and Outage Management systems, that it had chosen the most prudent and efficient option, where the opex required to implement the solution through the cloud is less than a corresponding capex-driven solution to implement the same functionality.

  AusNet Services provided further information about the forecasts associated with the options analysis for implementing the Customer Relationship Management and Operating Management systems (including a capex option). AusNet Services provided evidence demonstrating that the cost forecasts had undergone an external review by Deloitte Consulting using industry benchmarks of internal and contract labour, material cost and time estimates.[147]
- Engagement with the Customer Forum on AusNet Services' revised proposal, indicating it was still supportive of the inclusion of this step change as it considers the functionality that will be funded is required to improve the experience of customers.[148]

Some stakeholder submissions expressed their support for this proposed step change. The CCP17 submitted it does not oppose AusNet Services' 'cloud based' approach if this is demonstrated to be the most effective technical solution. However it opposed acceptance unless the AER is convinced that the project is justified, provides sound benefits for customers and is not replicating potential Customer Service Incentive Scheme rewards.[149] The VCO supported this step change if a new benefit for consumers is identified.[150]

For our final decision we have included $2.6 million ($2020–21) in our alternative estimate for the IT cloud step change. We consider the proposed step change meets the requirements for a capex/opex trade-off as it has the highest net present value in meeting the required functionalities and the proposed opex solution is lower cost than the capex solution.

We do not consider AusNet Services' proposed IT cloud step change duplicates the Customer Service Incentive Scheme rewards on the basis that customer relationship

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146 AusNet Services, *Revised regulatory proposal 2022–26 – Appendix 4c – Addendum – ICT cloud capex opex trade off,* December 2020.

147 AusNet Services, *Information request 069*, January 2021.

148 AusNet Services, *Revised regulatory proposal 2021–26 – Supporting document Appendix 3A – Customer Forum Memo,* December 2020, p. 2.

149 CCP17, Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26, January 2021, p. 88.

150 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 Submission to Initial Proposals, January 2021,* p. 55.

management, better planning and management of planned outages are not captured under this incentive scheme.

6.4.3.3 Five minute settlement

Consistent with our draft decision, our final decision is to include $3.5 million ($2020–21) in our alternative estimate.

Table 6.12 Five minute settlement ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services revised proposal	0.5	1.4	0.4	0.6	0.7	3.5
AER final decision	0.5	1.4	0.4	0.6	0.7	3.5
Difference	–	–	–	–	–	–

Source: AusNet Services, information request #089, March 2021.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we were satisfied that the proposal was prudent to meet the five minute settlement rule published by the Australian Energy Market Commission (AEMC) on 28 November 2017[151] and made minor adjustments to the proposed cost to align with our rate of change decision.[152]

AusNet Services' revised proposal accepted our draft decision.[153]

As a result, our final decision includes a step change for five minute settlement in our alternative estimate which is consistent with AusNet Services revised proposal, updated to include some mechanical updates for inflation and price growth.

6.4.3.4 Insurance premiums

Our final decision is to include a step change of $45.1 million ($2020–21) for increases in insurance premiums in our alternative estimate (but not to allow a cost pass through event for insurance premiums).

Table 6.13 Insurance premiums ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services updated revised proposal	4.8	6.8	8.9	11.1	13.4	45.1

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151 AEMC, *Five Minute Settlement, final determination,* 28 November 2017.

152 AER, *Draft Decision, AusNet Services 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 54–55.

153 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 84.

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AER final decision	4.8	6.8	8.9	11.1	13.4	45.1
Difference	–	–	–	–	–	–

Source: AusNet Services, *Information request #089,* March 2021.; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In AusNet Services' revised proposal, it proposed a combination of a step change and a cost pass. This included a step change for insurance premium increases known as a result of the latest insurance renewals ($10.5 million ($2020–21)) from its base year and a proposed cost pass through for future increases over the 2021–26 regulatory control period.[154]

Our assessment of AusNet Services' revised proposal revolved around two key areas:

- whether we could estimate the prudent and efficient insurance premium forecasts over the 2021–26 regulatory control period and how much certainty there was around these forecasts
- how these costs should be recovered – via a step change or through a cost pass through mechanism.

To better understand these issues, we engaged expert consultant Taylor Fry to assist our assessment.[155] We asked them to review AusNet Services' revised proposal and the additional information that AusNet Services provided from its insurance brokers (AON) in relation to the expected insurance premium price increases over the 2021–26 regulatory control period.

The key conclusions from Taylor Fry's report are that the forecasts provided by AON are directionally consistent with Taylor Fry's expectations of future premiums, given its understanding of the prevailing market conditions, and can be considered reasonable. However, the advice also explains there is significant uncertainty and variability in forecasting insurance premiums over a five year period.[156]

On balance, we are of the view that in the current circumstances, while there is some uncertainty associated with forecasting insurance premium increases (and consequently a risk of over or under estimating those increases), it is appropriate for us to use the forecasts of future insurance premium increases to include a step change in our alternative estimate. This position takes into account:

- Taylor Fry's findings that it is more likely that AusNet Services' will likely have to purchase lower levels of cover due to further withdrawals of capacity from the

[154] AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, pp. 89, 156–159.

[155] Taylor Fry, *AER AusNet Services Bushfire Insurance Public summary*, March 2021.

[156] Taylor Fry, *AER AusNet Services Bushfire Insurance Public summary*, March 2021, p. 3.

market as well as the reasonableness and likelihood of the insurance premium forecasts provided by AusNet Services.

- Consistency with our incentive based regulation framework, where businesses are best incentivised to achieve efficient cost outcomes by including costs in the total opex forecast. An example of this is AusNet Services' decision (after consulting with its customers) to raise its deductible from $10 million to $25 million in order to cut in half the premium increases in its 2020–21 renewal.[157]

We also consider that when the step change is added to the other elements of the opex forecast, the total opex amount meets the opex criteria based on the information we have available. In reaching this position we took into account stakeholder submissions summarised below.

The VCO supported analysis of the insurance premium proposals to ensure that the step change and cost pass through events are not double counted. It noted there is support for developing the most efficient bushfire insurance program for each business with consumers sharing in the increased costs and risks, including general insurance which it considered had not been impacted by the increased bushfire risk.[158]

The CCP17 submitted it is aware that insurance coverage is decreasing, while insurance costs are rising rapidly for all Australian electricity network businesses. The CCP17 viewed the changes to insurance markets to be material and beyond reasonable budget projections, with these changes likely to be sustained over a long period due to climate change. Consequently, the CCP17 accepted that the higher insurance prices are likely to remain over the coming regulatory period.[159]

Consultant for ECA, Spencer&Co supported the steps taken by businesses to mitigate the costs impacts of rising insurance premiums on customers. They also considered that the businesses response to insurance premium increases is reasonable in the circumstances.[160]

We acknowledge the benefits of using a cost pass through for businesses to recover insurance premium costs over the next regulatory period. These include that a cost pass through lessens the need to set a forecast when there is significant uncertainty and customers only pay for higher costs when they are known during the period. However, we consider on balance that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

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[157] AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 88.

[158] Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 56.

[159] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 61–63.

[160] Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 15.

During our assessment process we shared these views with AusNet Services, and subsequently AusNet Services provided an updated revised proposal which included a step change for all insurance premium increases over the 2021–26 regulatory control period of $45.1 million ($2020–21). Based on our review, including our consultant's advice, we consider this to be a reasonable forecast for AusNet Services and have included this amount in our alternative estimate. We also note that the rate of change increases proposed by AusNet Services over the 2021–26 regulatory control period generally align with the proposals from Powercor, United Energy and Jemena. As a result, we have not accepted the proposed insurance premium nominated cost pass through event for the 2021–26 regulatory control period. See attachment 15 for further discussion.

6.4.3.5 2019–20 Summer bushfire cost pass through avoided costs

Our final decision is to include a step change of –$0.5 million ($2020–21) in our alternative estimate reflecting 2019–20 bushfire costs that will be avoided as a result of works bought forward and separately funded under a cost pass through event application.

Table 6.14 Bushfire cost pass through avoided costs ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	–0.1	–0.1	–0.1	–0.1	–0.1	–0.5
AER final decision	–0.1	–0.1	–0.1	–0.1	–0.1	–0.5
Difference	–0.0	–0.0	–0.0	–0.0	–0.0	–0.0

Source: AusNet Services, *information request #089,* March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

AusNet Services included a new –$0.5 million ($2020–21) step change in its revised proposal to reflect savings for ongoing bushfire-related maintenance activities that were brought forward, or superseded, as a result of the remediation activities required in response to the 2019–20 bushfires. These works included vegetation management and asset inspection activities (and associated repair work) and were a part of a separate cost pass through event application from AusNet Services.[161]

There were minor discrepancies between the proposed savings included in the revised proposal and the savings forecast in the cost pass through application. We have included a step change of –$0.5 ($2020–21) consistent with the forecast savings identified and accepted in its 2019–20 bushfire cost pass through application.[162]

161 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, pp. 89–90.

162 AusNet Services, *Cost pass through application - 2020 Summer Bushfires*, May 2020, p. 24.

6.4.4 Category specific forecasts

We have included three expenditure items, debt raising costs, innovation and GSL payments, in our alternative estimate of total opex as category specific forecasts, which we did not forecast using the base-step-trend approach.

6.4.4.1 GSL payments

We have included a category specific forecast of $32.7 million ($2020–21) for GSL payments in our alternative estimate. This is lower than the forecast of $45.9 million ($2020–21) that AusNet Services included in its revised proposal.[163] It is also lower than the forecast of $46.0 million ($2020–21) we included in our draft decision.[164]

In capturing the impact of the changes to the GSL scheme (set out below), AusNet Services proposed both a forecast of GSL payments for the 2021–26 regulatory control period and a 'transitional' amount to recover abnormally high GSL payments in the 2015 to 2019 period due to events it considered were beyond its control. Our alternative estimate of the GSL payments for the 2021–26 regulatory control period is very similar to AusNet Services' forecast. Our lower total GSL forecast is largely driven by our lower alternative estimate for the 'transitional amount' (see Table 6.16). While we consider it appropriate to provide a 'transitional amount' we consider that it should be calculated in a way that accounts for all changes in the GSL scheme and the abnormality of the 2015 to 2019 period.

We discuss how we have forecast GSL payments, and why our forecast differs from AusNet Services' revised proposal, below.

GSL reliability payments are payments AusNet Services is required to pay to customers that experience outages that do not meet a set standard. In Victoria, the criteria for GSL payments are set by the Essential Services Commission (Victoria). Consistent with our draft decision, we have updated our forecast of GSL payments in this final decision to reflect the revisions made to the GSL scheme by the Essential Services Commission in November 2020.[165]

In its revised proposal, AusNet Services updated its forecast of GSL payments to account for the changes made by the Essential Services Commission. Its revised proposal also included a 'transitional amount' in addition to its forecast of the GSL payments it expected to incur in the 2021–26 regulatory control period.

AusNet Services forecast GSL payments using its outage data for the years 2015 to 2019. It calculated the GSL payments it would have incurred in those years had the new scheme been in place and averaged these 'backcasts' to derive its forecast. In

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163 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, pp. 91–94.

164 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure*, September 2020, pp. 60–61.

165 Essential Services Commission (Victoria), *Electricity Distribution Code customer service standards final decision*, 16 November 2020.

this way it forecast GSL payments totalling $29.8 million ($2021–21) for the 2021–26 regulatory control period.[166]

In addition, it proposed a 'transitional amount' of $16.1 million ($2021–21). AusNet Services stated that from 2015 to 2019, it made significant GSL payments for events that were outside of its control. Due to the changes to the GSL scheme, many of these payments were excluded from its backcast payments under the new scheme and thus not included in AusNet Services' forecast GSL payments for the 2021–26 regulatory control period. The proposed 'transitional amount' would recover these GSL payments. AusNet Services also adjusted its proposed 'transitional amount' to account for the time value of money.[167]

Table 6.15 Forecast GSL payments, ($ million, 2020–21)

	AusNet Services' proposal	AER alternative estimate	Difference
Forecast GSL payments	29.8	28.8	–1.0
Transitional amount	16.1	3.9	–12.2
Total	**45.9**	**32.7**	**–13.2**

Source: AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, pp. 91–92; AER analysis.

Revisions to the GSL scheme

In our draft decision we noted that the Essential Services Commission was reviewing the consumer protection framework in the Electricity Distribution Code, including the GSL scheme. We stated that we would update the GSL payment forecasts in our final decision to account for the GSL scheme changes, once finalised.[168] The Essential Services Commission published its final decision in November 2020.[169] In its decision, the Essential Services Commission made a number of revisions to the scheme, including:

- removing outages on major event days and all exclusions from counting toward duration or frequency payments
- updated the duration and frequency thresholds to reflect the removal of outages on major event days and all exclusions from counting toward duration or frequency payments

166 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 91.

167 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 92.

168 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure*, September 2020, pp. 60–61.

169 Essential Services Commission (Victoria), *Electricity Distribution Code customer service standards final decision*, 16 November 2020.

- replacing single interruption supply restoration payments with major event day payments, such that customers receive a payment if they are without supply for 12 hours or more on a major event day
- giving customers access to both major event day payments and duration payments (previously customers did not receive a single interruption supply restoration payment if they received a duration payment)
- adjusting the GSL performance payment levels
- updating the definitions of sustained and momentary interruptions to align with the national framework (so a momentary interruption is defined as less than three minutes and a sustained interruption is more than three minutes).[170]

Why we use a five year historic average to forecast GSL payments

To forecast GSL payments for the current regulatory control period our standard approach is to use a five year historic average of GSL payments. This approach provided both an estimate of efficient GSL payments as well as shared any under or overspends incurred in the averaging period. It did this by allowing the business to get back any over spends (or 'pay back' under spends) in the five years of the following control period.

However, when there are changes to the GSL scheme, using an average of actual GSL payments may not produce a forecast that reflects the changed scheme. Using instead an average of the payments that would have been incurred under the new scheme may not provide both an estimate of efficient GSL payments as well as share any under or overspends. This is because such a forecast would not be based on the distributor's actual GSL payments, and thus may not share its actual over or underspends.

Whether or not the forecast of GSL payments is required to provide for the sharing of under or overspends to account for scheme changes will depend on whether or not there have been any abnormal events which resulted in under or overspends. When there were no abnormal events in the averaging period, then the forecast will appropriately provide the expected GSL payments under the new scheme. That is, when there have been no abnormal events the GSL allowance does not need to also provide for the sharing of the GSL payments associated with abnormal events.

If there were abnormal events in the averaging period, then how the GSL over or underspends associated with those events are shared will depend on how the GSL scheme changes:

- If the backcast overspends (underspends) due to the abnormal events are less than the overspends (underspends) actually incurred, then AusNet Services would not fully recover its actual overspends (underspends).

170 Essential Services Commission (Victoria), *Electricity Distribution Code customer service standards final decision*, 16 November 2020.

- Similarly, if the backcast overspends (underspends) due to the abnormal events are greater than the overspends (underspends) actually incurred, then AusNet Services would recover more than its actual overspends (underspends).

To account for the changes to the GSL scheme we need to add the incremental impact of the scheme changes to our standard approach of using a five year historic average of actual GSL payments. The incremental impact of the scheme changes is the differences between expected GSL payments under the new scheme and expected GSL payments under the current scheme. This approach can be expressed as:

$$GSL\ allowance = 5\ year\ average\ payments\ (current) + [expected\ payments\ (new) - expected\ payments\ (current)]$$

However, this approach is not directly comparable to AusNet Services' proposal. That is, it is not comprised of a forecast of GSL payments under the new GSL scheme and a 'transitional amount'. But the above equation can be rearranged to make it comparable to AusNet Services' proposed allowance:

$$GSL\ allowance = expected\ payments\ (new) + [5\ year\ average\ payments\ (current) - expected\ payments\ (current)]$$

Under this construction the expected payments under the new scheme provides the forecast of the GSL payments likely to be incurred in the next regulatory control period. The difference between the five year average payments under the current scheme and the expected payments under the current scheme provides the 'transitional amount'. Deriving the 'transitional amount' in this way would pay back the additional GSL payments it incurred in abnormal years.

We have used our alternative approach to calculate a forecast of the GSL payments AusNet Services is likely to incur in the 2021–26 regulatory control period as well as a 'transitional amount' that we consider fairly shares AusNet Services GSL over and underspends in the 2015 to 2019 period with its customers. We discuss this in more detail below.

Forecast GSL payments

Looking first at the forecast of GSL payments, we are not satisfied that AusNet Services' forecast reasonably reflect the GSL payments it is likely to incur in the 2021–26 regulatory control period. AusNet Services forecast GSL payments of $29.8 million ($2020–21), which reflects the GSL costs it would have incurred in the 2015–19 period had the new GSL scheme been in place.[171]

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[171] AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 91.

Instead we have used in our alternative estimate a ten year average of the GSL payments that AusNet Services would have paid under the new scheme as the best estimate of the GSL payments it is likely to incur in the 2021–26 regulatory control period. Using a longer term average reduces the impact of abnormal, or outlier events and is more likely to reflect the likely costs to be incurred. We think this is particularly important given the significant volatility displayed in the 2015 to 2019 period. AusNet Services' GSL payments under the current scheme varied from $2.8 million (nominal) in 2017 to $17.4 million (nominal) in 2016 (see Table 6.17). In its response to an information request on how to forecast GSL payments, AusNet Services stated:[172]

> For the avoidance of doubt, the concerns raised by AusNet Services do not relate to the forecasting approach of GSL opex, being an averaging approach of recent years payment data. We consider that given the nature of the GSL scheme (for example, the year-on-year volatility and the incentive impacts of alternative ways of forecasting, which were not contemplated in the scheme's design), this is an appropriate way to forecast GSL opex.

However, we consider that using an average of five years of data (from 2015 to 2019) to forecast GSL payments is inconsistent with AusNet Services' proposal that a 'transitional amount' is also required. By this we mean that the proposed 'transitional amount' is justified on the basis that extreme events occurred in the current five year period, coupled with the changes to the GSL scheme (because, as explained above, the abnormal events resulted in significant GSL payments that AusNet Services stated it would not get back due to the changes to the GSL scheme). So if extreme events occurred that require a 'transitional amount', we do not consider the same five year period should be used as the basis to forecast GSL payments.

To test the appropriateness of the 2015 to 2019 period for forecasting, we compared the outage data in those years to the previous five years. AusNet Services provided backcast outage data under the current GSL scheme back to 2010.[173] (Although we note that the backcast data for the current scheme did not include single event payments for the years 2010 to 2014. We do not, however, consider the absence of this data significantly impacts the analysis.) We found that the payments made under the current scheme in the years 2010 to 2014 (which averaged $7.3 million) were significantly lower than those in the years 2015 to 2019 (which averaged $9.0 million, see the first row in Table 6.17). This supports AusNet Services claim that the 2015 to 2019 period included extreme events. As a result it incurred unforecast GSL payments that it will not recover in the next regulatory control period due to the changes to the GSL scheme (discussed further below). However, we consider that this also shows that the last five years were not typical and are not a reasonable basis for forecasting GSL payments going forward.

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[172] AusNet Service, *information request #067*, January 2021.

[173] AusNet Service, *information request #067*, January 2021.

Table 6.16 Backcast GSL payments ($ million, nominal)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average 2015–19	Average 2010–19
Current scheme	6.4	6.1	8.9	6.7	8.7	7.3	17.4	2.8	6.2	11.3	9.0	8.2
New scheme	5.1	4.9	6.4	5.3	6.1	5.6	10.9	3.0	5.0	8.2	6.5	6.0

Source: AusNet Service, *information request #067*, January 2021; AER analysis.

Note: The current scheme payment amounts exclude single event payments because AusNet Services did not provide these amounts for all ten years. The new scheme amounts for the years 2010 to 2013 are an estimate based on the current scheme amounts (excluding single event payments). See the discussion below for further details.

In these circumstances, we consider an average calculated over a longer period of time, such as 10 years (two regulatory control periods), would be more appropriate to forecast the GSL payments AusNet Services is likely to incur in the 2021–26 regulatory control period.

AusNet Services also provided outage data for the years 2014 to 2019 to calculate the GSL payments it would have incurred under the new GSL scheme. [174] It was not able to easily provide outage data for the years 2010 to 2013.

As we consider it would be appropriate to forecast GSL payments over a longer (10 year) period, we investigated if and how this could be done without outage data for 2010 to 2013. To do this we tested the statistical relationship between the total GSL payments under the new scheme and the payments (excluding single event payments) paid under the current scheme for the period 2014 to 2019. We found that there was a close statistical relationship.[175] Given these results, we consider this statistical relationship can be used to produce robust estimates of the GSL payments that would have been paid under the new GSL scheme in the years 2010 to 2013. We have shown these results in the second row of Table 6.17 (which shows the payments that would have been paid under the new scheme). While we recognise that these estimates for the period 2010 to 2013 will not be as accurate as a backcast calculated directly from the outage data for each customer in each year, we consider any difference would likely be small and unbiased. We have used these estimates, and the backcast payments for the years 2014 to 2019 based on outage data, to forecast the GSL payments AusNet Services is likely to incur in the 2021–26 regulatory control period. Accordingly we have forecast annual GSL payment of $6.0 million (nominal). This equates to a total forecast of $28.8 million ($2020–21) in real terms (see Table 6.18).

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[174] AusNet Service, *information request #067*, January 2021.

[175] A simple linear regression produced an R squared value of 0.993, showing that movement in the GSL payments incurred under the current scheme explained 99.3 per cent of the movement in the new scheme GSL payments. A plot of the regression results showed they fit the data well.

Table 6.17 Forecast GSL payments ($ nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26	TOTAL
10 year average, new scheme, nominal	6.0	6.0	6.0	6.0	6.0	**30.2**
Forecast GSL payments, $2020–21	6.0	5.9	5.8	5.6	5.5	**28.8**

Source: AER analysis

We have also considered whether GSL payments have been increasing over time (due to climate change, for example) and whether we need to account for such a trend when forecasting GSL payments. While AusNet Services' average GSL payments in the period 2015 to 2019 were higher than the previous five years (see Table 6.17) it is unclear whether this reflects an increasing trend. The significant volatility in the 2015 to 2019 period makes it difficult to identify any trend. We also note that the increase in GSL payments on AusNet Services' network is not seen consistently across the other Victorian networks.

We also looked at feeder level outage data for any trend in outages. We found that the system average interruption frequency index for each feeder class and network in the period 2015 to 2019 has been stable or declining compared to the period 2010 to 2014. This indicates that, on average, customers are not experiencing more outages over time. We also found that CitiPower, Jemena and United Energy have all reduced their system average interruption duration indexes in 2015 to 2019 compared to the period 2010 to 2014. Powercor's system average interruption duration indexes did increase on its long rural feeders. But we note that this did not lead to Powercor overspending relative to its GSL forecast in the 2015 to 2019 period. Consequently we are not satisfied that there is sufficient evidence to conclude that there is a trend increase in outages, beyond AusNet Services' control, that makes forecasting based on a ten year average unreasonable.

Transitional amount to share AusNet Services' GSL over and underspends

Secondly, looking at the forecast for a transitional amount to reflect under and overspends in the 2016–20 regulatory control period, we are satisfied that it is reasonable to provide an additional amount to share these amounts. We note that GSL payments were not included in the EBSS in the 2016–20 regulatory control period, or the 2011–15 period. We stated in our final decision for the 2016–20 regulatory control period:[176]

> We forecast GSL costs using a five year historical averaging approach to maintain consistency with our forecasting method for previous regulatory control periods. The incentives provided by using a five year historical average

[176] AER, *Final decision, AusNet distribution determination, Attachment 7, Operating expenditure*, May 2016, p. 92.

are consistent with adopting a single year revealed cost approach and applying the EBSS.

This shows that it was our intention that under and overspends from GSL payments be shared between AusNet Services and its customers like other opex costs. Consequently we have sought to calculate a 'transitional amount' in a way that achieves this.

We have calculated a 'transitional amount' of $3.9 million ($2020–21), which is less than the $16.1 million ($2020–21) proposed by AusNet Services. We have calculated our 'transitional amount' using the approach discussed above. That is, we have calculated it as the difference between the five year average of GSL payments under the current scheme and the expected payments under the current scheme (see Table 6.19). Consistent with how we have forecast the expected payments under the new scheme, we have calculated the expected payments under the current scheme as the average of the ten year average of GSL payments under the current scheme. We consider the reasons for using a ten year average to forecast GSL payments, discussed above, apply equally to calculating the 'transitional amount'. This gives an annual a total 'transitional amount' of $3.9 million ($2020–21).

Table 6.18 Forecast GSL payments and 'transitional amount'

	2021–22	2022–23	2023–24	2024–25	2025–26	TOTAL
10 year average, current scheme, nominal	8.4	8.4	8.4	8.4	8.4	**42.1**
5 year average, current scheme, nominal	9.2	9.2	9.2	9.2	9.2	**46.2**
Transitional amount, nominal	0.8	0.8	0.8	0.8	0.8	**4.1**
Transitional amount', $2020–21	0.8	0.8	0.8	0.8	0.8	**3.9**

Source: AER analysis

We consider that AusNet Services' approach to calculating the 'transitional amount' overstates the amount required for two reasons:

1. it does not account for all changes in the GSL scheme
2. it relies only on data from an abnormal period.

We agree with AusNet Services that the changes to the treatment of major event days under the new scheme have the biggest impact on the GSL payments that AusNet Services will incur in the next regulatory control period. However, we consider that the impacts of the other changes should also be accounted for. Furthermore, we note that the changes the Essential Services Commission made to the GSL scheme were considered as a package. For example, the Essential Services Commission stated that it updated the duration and frequency thresholds to reflect the removal of outages on major event days and all exclusions from counting toward duration or frequency payments.[177] Our approach, outlined above, accounts for all changes.

AusNet Services stated that an alternative approach that accounts for all changes yields a similar outcome to its proposed approach. Specifically, AusNet Services' alternative approach would result in a 'transitional amount' of $13.0 million ($2020–21), or $15.6 million ($2020–21) when the time value of money is accounted for.[178] However, AusNet Services' alternative approach was to calculate the difference between a five year average of GSL payments backcast under the new scheme and a five year average of actual GSL payments (under the current scheme). The net impact of adding a transitional amount equal to the difference between the two schemes to a GSL payments forecast equal to an average of payments under the new scheme would set a total GSL allowance equal to the average of its payments under the current scheme. Consequently, such an approach would not account for any of the changes to the GSL scheme. The total GSL allowance would simply reflect the average of the payments it incurred under the current scheme. We do not agree that the fact that AusNet Services' proposed GSL allowance, inclusive of its 'transitional amount', is similar to the average of its actual GSL payments in 2015 to 2019 supports its proposed approach to calculating the 'transitional amount'.

We have shown, and AusNet Services agreed, that a change in GSL payments due to scheme changes does not require a 'transitional amount' if there have been no abnormal events in the averaging period.[179] AusNet Services' approach to calculating the 'transitional amount', by relying only on five years of data, fails to account for the abnormality of the current five year period. We consider any reasonable approach would need to account for the abnormality of the period 2015 to 2019. Our approach does this by comparing the GSL payments paid out in the 2015 to 2019 period to the payments it would have had to pay in normal conditions as proxied by the payments over the period 2010 to 2019.

We also note that AusNet Services' actual GSL payments in the period 2015 to 2019 totalled $5.6 million ($2020–21) more than the GSL payment forecasts included in its approved total opex forecasts. If the purpose of the 'transitional amount' is to share the GSL over and under spends AusNet Services incurred in the 2015 to 2019 period, a 'transitional amount' of $16.1 million ($2020–21) appears unreasonable, given it is almost three times the overspend it actually incurred.

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177 Essential Services Commission, *Electricity Distribution Code customer service standards final decision*, 16 November 2020, p. 48.

178 AusNet Services, *information request #067*, January 2021.

179 AusNet Services, *information request #067*, January 2021.

The 'transitional amount' should not be adjusted for the time value of money

AusNet Services proposed that the 'transitional amount' be adjusted to account for the time value of money.[180] AusNet Services stated that the GSL scheme is different from other incentive schemes because:[181]

- the aim is to recognise that some customers have been inconvenienced by outages
- it is a redistribution scheme that transfers payments from all of its customers to a select group of impacted customers
- it is not designed to incentivise investment in the network
- events that trigger large GSL payments to customers, such as the 2016 storm, are not within AusNet Services' control.

For these reasons AusNet Services argued that it should not bear the financial penalty that comes with the GSL scheme.[182]

However, we consider that adjusting the 'transitional amount' for the time value of money would be inconsistent with both the regulatory framework and our decision for the 2016–20 regulatory control period.

The regulatory framework established by the NER is an incentive based one, not a cost plus one. Consistent with this, we included a forecast of GSL payments in its ex-ante opex forecast for the 2016–20 control period. The forecast was based on an historic average of GSL payments, thus sharing under and overspends on GSL payments in a similar way to other opex costs which are subject to the EBSS.[183] The final decision did not provide a true-up in the control mechanism to compensate AusNet Services for its actual GSL payments. We explicitly considered the option of allowing AusNet Services to recover its actual GSL costs and stated:[184]

> The CCP also suggested that GSL costs "could be recovered during the course of the regulatory period". We consider providing for GSL payments in our ex-ante opex forecast provides network service providers with an incentive to minimise those payments and to maintain service levels at an efficient level. Actual GSL costs may be either higher or lower than forecast as they depend on the frequency of unplanned outages. Recovering GSL costs ex-post, as the CCP suggests may reduce the incentive for distributors to maintain service levels.

180 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 92.

181 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, pp. 93–94.

182 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 94.

183 AER, *Final decision, AusNet distribution determination, Attachment 7, Operating expenditure*, May 2016, p. 92.

184 AER, *Final decision, AusNet distribution determination, Attachment 7, Operating expenditure*, May 2016, p. 93.

To now compensate AusNet Services for its actual GSL payments in the 2016–20 regulatory control period, rather than sharing the under and overspends, would retrospectively change that decision.

In its revised proposal, AusNet Services stated:[185]

> We note that in incentive schemes such as the EBSS and CESS, the costs and benefits of underspends and overspends varies from year to year and are shared between a DNSP and its customers. These schemes operate on the premise that the underlaying parameters are within a DNSP's control, therefore the financial rewards or penalties are warranted.

This statement is incorrect. The EBSS is designed to share efficiency gains and losses associated with all opex costs, regardless of whether they are 'controllable' or not. In consulting on version 2 of the EBSS, we explicitly considered how 'uncontrollable' costs should be treated. In the explanatory statement published with the final decision on the EBSS, we stated:[186]

> In our draft EBSS, we considered there was no strong reason why we should exclude nominated 'uncontrollable' cost categories from the EBSS. By including such costs in the EBSS, uncontrollable cost decreases or increases are shared between NSPs and consumers in the same way as any efficiency gain or loss (that is, approximately 30:70 with a five year carryover period). If we excluded such costs, uncontrollable cost increases would be shared in the same way as an efficiency loss would be without an EBSS. Without an EBSS, NSPs' share of cost increases differs across the regulatory control period. We saw no reason why uncontrollable cost increases should be shared differently between NSPs and consumers in different regulatory years…
>
> We acknowledge the EBSS will reward or penalise NSPs for some forecasting error associated with uncontrollable events. However, on the whole, the risk of uncontrollable events presents both upside and downside risk to NSPs. Relevantly, any material risks can be managed through pass-through events and contingent projects. We do not think there is a compelling argument to share the cost of uncontrollable events differently to all other costs facing NSPs.
>
> While some events may be uncontrollable, NSPs usually have some control over the costs associated with such events. Allowing exclusions would reduce the incentive to respond to such events efficiently.

Consistent with this, we maintain the view that GSL payment over and underspends should not be treated differently to other opex over or underspends because they are 'uncontrollable'. Further, and consistent with the EBSS explanatory statement, we consider that while the occurrence of major event days may be beyond the control of

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185 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 93.

186 AER, *Explanatory statement, Efficiency benefit sharing scheme*, November 2013, p. 19.

AusNet Services, they are often predictable (from weather forecasts, for example) and AusNet Services can control how it prepares for, and responds to, major event days.

Consistent with the reasons given in the EBSS explanatory statement, we consider the pass through framework is the appropriate mechanism to deal with material uncontrollable events. Accordingly, we consider that AusNet Services' GSL over and underspends should be shared consistently with other opex over and underspends. The approach we have used to calculate the 'transitional amount' achieves this.

6.4.4.2 Innovation

Consistent with our draft decision,[187] our final decision is to include a category specific forecast of $1.2 million ($2020–21) to fund innovation projects to test ways of managing low voltage networks and improving network management.

Table 6.19 Innovation ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services' revised proposal	0.2	0.2	0.2	0.2	0.2	1.2
AER final decision	0.2	0.2	0.2	0.2	0.2	1.2
Difference	0.0	0.0	0.0	0.0	0.0	0.0

Source: AusNet Services, *information request #089,* March 2021; AER analysis.

Note: Numbers may not add due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In our draft decision, we accepted the proposed category specific forecast for innovation as it was supported by the Customer Forum and, as a category specific forecast, it will not become a part of recurrent expenditure.

AusNet Services' revised proposal accepted our draft decision.[188] Therefore, we have included this category specific forecast in our alternative estimate.

6.4.4.3 Debt raising costs

We have included debt raising costs of $11.4 million ($2020–21) in our alternative estimate. This is $0.1 million ($2020–21) higher than the $11.3 million ($2020–21) forecast proposed by AusNet Services.[189]

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. The appropriate approach is to forecast debt raising costs using a

[187] AER, *Draft decision, AusNet Services determination 2021–26, Attachment 6 Operating expenditure,* September 2020, pp. 61–63.

[188] AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 94.

[189] AusNet Services, *information request #089,* March 2021.

benchmarking approach rather than a service provider's actual costs in a single year. This provides for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs which is discussed further in Attachment 3 to the draft decision.[190]

6.4.5 Assessment of opex factors

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the 'opex criteria' under the NER, we have regard to the 'opex factors'.[191]

We attach different weight to different factors when making our decision to best achieve the National Electricity Objective. This approach has been summarised by the AEMC as follows:[192]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.21 summarises how we have taken the opex factors into account in making our final decision.

Table 6.20 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark opex that would be incurred by an efficient distribution network service provider over the next regulatory control period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark opex that would be incurred by an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by an efficient provider for that particular network over the relevant period. We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include productivity index number and opex cost function modelling. We have used our judgment based on the results from all of these

190 AER, *Draft decision, AusNet Services determination 2021–26, Attachment 3 – Rate of return, September 2020, pp. 10–12.*

191 *NER*, cl. 6.5.6(e).

192 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, p. 115.

Opex factor	Consideration
	techniques to holistically form a view on the efficiency of AusNet Services' proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of AusNet Services' actual past opex with that of other service providers to form a view about whether or not its revealed opex is efficient such that it can be relied on as the basis for forecasting required opex in the forthcoming period.
The extent to which the opex 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.	This particular factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their proposals, such that they factor in the needs of consumers.[193] Based on the information provided by AusNet Services in its revised proposal and the CCP17's advice, we consider AusNet Services consulted with consumers in developing its revised proposal, including through its Customer Forum. We have examined the issues raised by consumers in developing our alternative estimate of opex, e.g. the step changes for IT cloud and insurance and taken this into account as part of considering these factors.
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering AusNet Services' proposed step changes. For instance we considered whether a step change for IT cloud is an efficient capex/opex trade-off. We considered whether there are capex and opex solutions in considering this step change. We have had regard to multilateral total factor productivity analysis when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs with respect to the relative prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering AusNet Services' proposed step changes. Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs. Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.

[193] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, Final Rule Determination*, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
Whether the opex 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 incentive scheme that applied to AusNet Services' opex in the 2016–20 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our estimate of base opex consistently in applying the EBSS and forecasting AusNet Services' opex for the 2021–26 regulatory control period.
The extent the opex 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.	Our primary tools assess total opex efficiency, with supporting tools examining the efficiency of both opex and capital inputs as well as at the category level. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of its arrangements with related providers.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our final decision.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we must identify any regulatory investment test (RIT-D) submitted by the business and ensure the conclusions of the relevant RIT-D are appropriately addressed in the total forecast opex. AusNet Services did not submit any RIT-D project for its distribution network.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify AusNet Services of any other opex factor.

Source: AER analysis.

Shortened forms

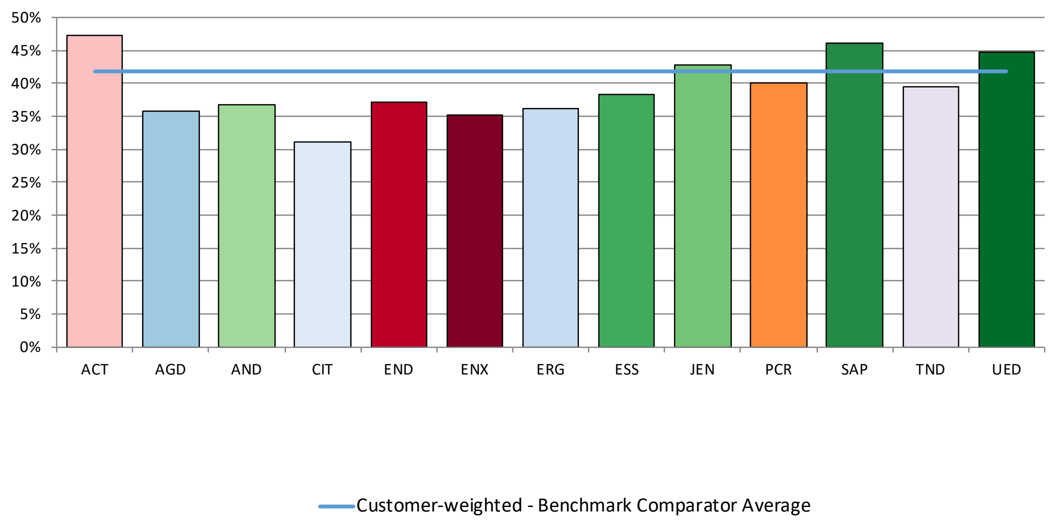
Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAM	cost allocation method
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
distributor	distribution network service provider
DNSP	distributor
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ESV	Energy Safe Victoria
GSL	guaranteed service levels
MPFP	multilateral partial factor productivity
MTFP	multilateral total factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
OEFs	operating environment factors
opex	operating expenditure
PPI	partial performance indicators
Pricing Order	electricity pricing order
PTRM	post-tax revenue model
RBA	Reserve Bank of Australia
REFCL	Rapid Earth Fault Current Limiter
RIN	regulatory information notice

A Our analysis of the opex/capital ratios that inform the extent of capitalisation practice differences

As discussed in section 6.4.1.2, we have now included an OEF adjustment to account for AusNet Services' capitalisation practices being materially different to the comparator businesses. In making this assessment we have been informed by the extent to which AusNet Services' opex/totex, opex/total cost, and opex/total inputs ratios differ to the comparator businesses'. In this appendix, we present updated ratios for both benchmarking periods and discuss their advantages and disadvantages below.

The average opex/totex ratio for all the distribution businesses is shown in Figure A. 1 and Figure A. 2 for the 2006–19 period and 2012–19 periods.

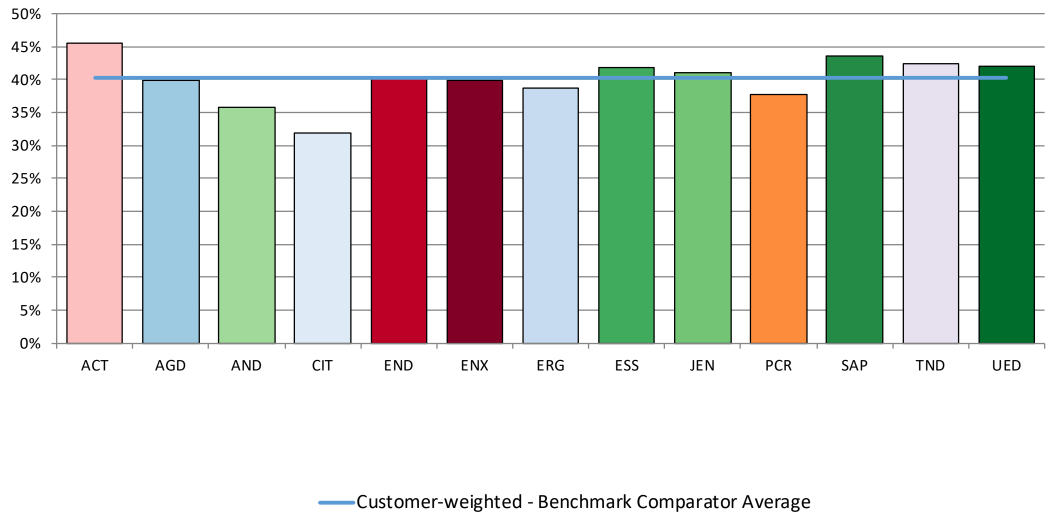
Figure A. 1 Opex to totex ratios for distribution businesses, 2006–19[194]



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

194 Consistent with the opex series used for economic benchmarking, these charts use 2014-CAM backcast opex for those distribution businesses which have changed their CAM.

Figure A. 2 Opex to totex ratios for distribution businesses, 2012–19



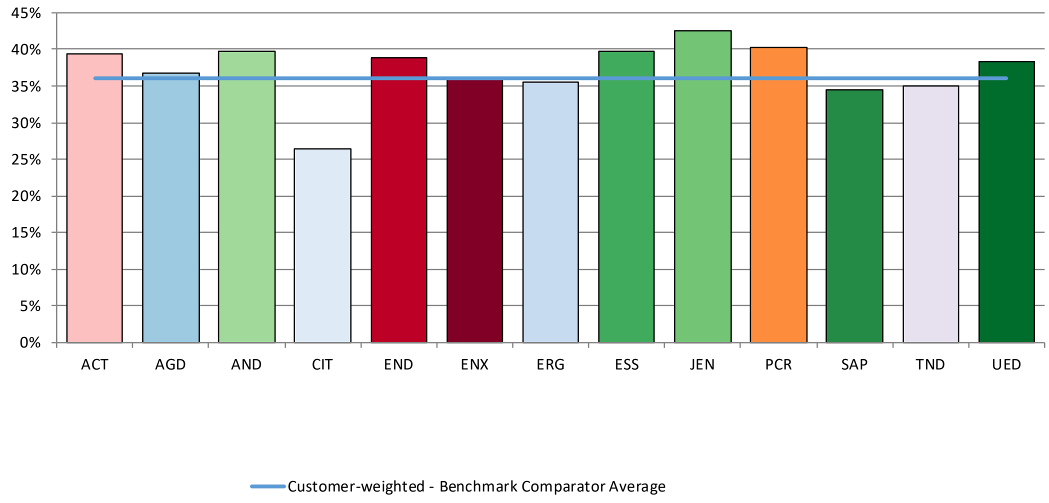
Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

We find that AusNet Services opex/totex ratio is 11–12 per cent below the benchmark comparator-average ratio across the two periods.

The key advantage of the opex/totex ratio is that it captures important dollar-for-dollar swings between opex and capex over the benchmarking period, such as capitalisation/expensing decisions on overheads. However, as an expenditure and flow-based measure, despite calculating it over a relatively long period, it is also likely subject to volatility. Several concerns were raised with the opex/totex ratio such as that other factors may be influencing the opex/totex ratio that are not related to the opex/capex mix, such as capital contributions. We have considered these concerns and consider that while the ratio will pick up some 'noise', this does not invalidate the use of this ratio as a high level gauge of capitalisation practices, particularly when used in combination with other ratios.

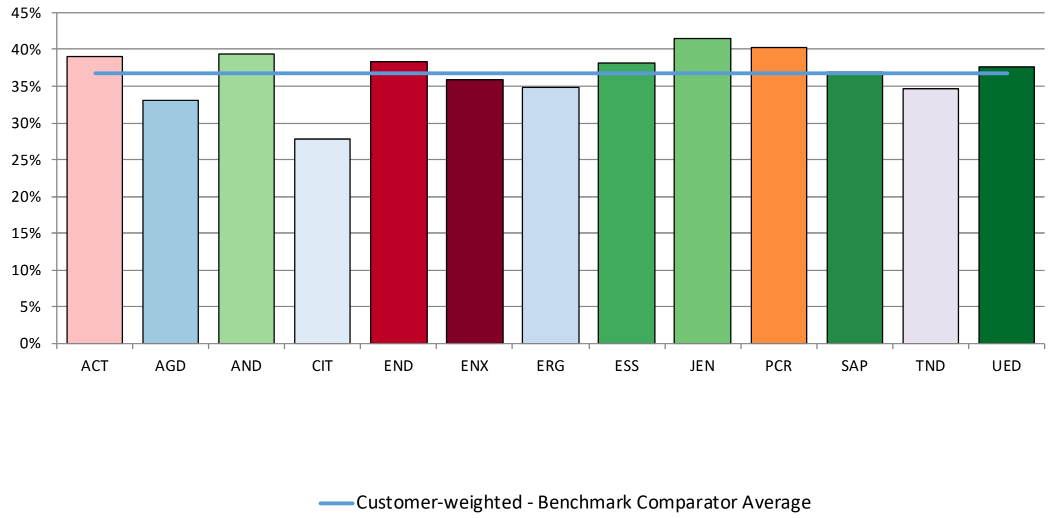
The average opex/total cost ratio for all the distribution businesses is shown in Figure A. 3 and Figure A. 4 for the 2006–19 period and 2012–19 periods.

Figure A. 3 Opex to total cost ratios for distribution businesses, 2006–19[195]



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

Figure A. 4 Opex to total cost ratios for distribution businesses, 2012–19



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

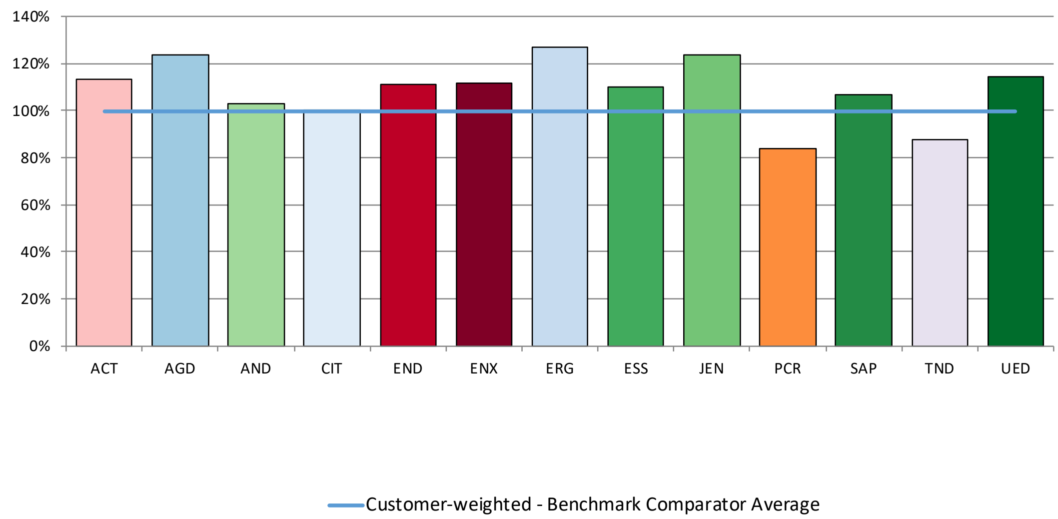
195 Consistent with the opex series used for economic benchmarking, these charts use 2014-CAM backcast opex for those distribution businesses which have changed their CAM.

We find that AusNet Services opex/total cost ratio is now 7–10 per cent above the benchmark comparator-average ratio across the two periods.

Compared to the opex/totex ratio, the opex/total cost ratio is more theoretically consistent with the cost- rather than expenditure-based approach used in benchmarking. The annual user cost of capital is based on a stock measure for the durable capital input,[196] and thus supplements the above flow-based measure (i.e. opex/totex). While capital inputs is largely captured de facto in the benchmark modelling (due to its collinearity with the output variables), this holds for the average business in the data that holds a particular degree of capital intensity (capital inputs relative to opex). We consider that businesses such as AusNet Services with materially different capitalisation practices, as indicated by its opex/total cost ratio, may not be sufficiently captured. Against these advantages, average user cost is an imperfect measure of capital inputs, due to potential inconsistencies among the distribution businesses in approaches to (initial) regulatory asset base valuation.

The average opex/total inputs ratio for all the distribution businesses is shown in Figure A. 5 and Figure A. 6 for the 2006–19 period and 2012–19 periods.

Figure A. 5 Opex to total inputs ratios for distribution businesses, 2006–19[197]

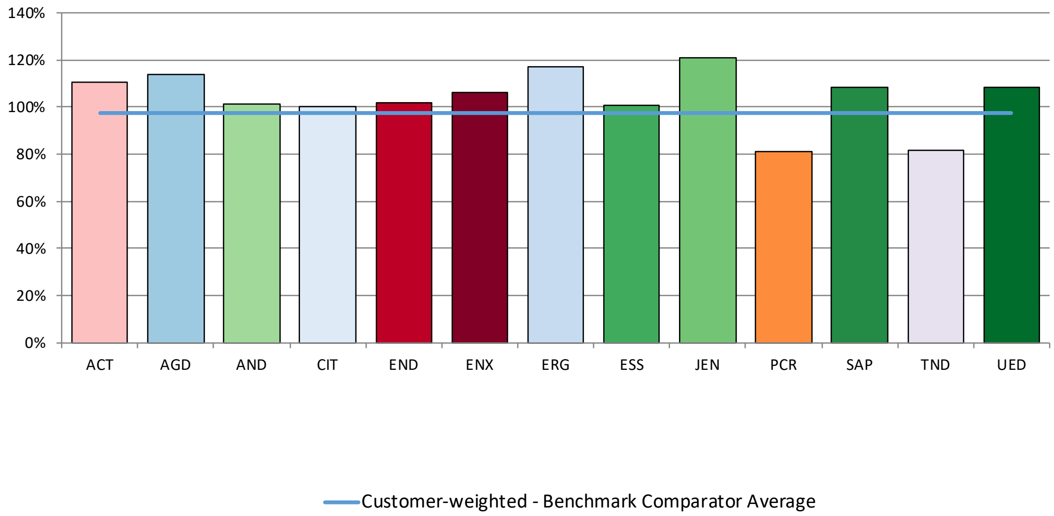


Source: Economic Benchmarking RINs, all distribution businesses; Economic Insights, Files for 2020 DNSP Economic Benchmarking Report, 8 October 2020; AER analysis.

196 This assumes that the periodic flow of capital services is in proportion to the capital stock in place.

197 Consistent with the opex series used for economic benchmarking, these charts use 2013-CAM backcast opex for those distribution businesses which have changed their CAM.

Figure A. 6 Opex to total inputs ratios for distribution businesses, 2012–19



Source: Economic Benchmarking RINs, all distribution businesses; Economic Insights, Files for 2020 DNSP Economic Benchmarking Report, 8 October 2020; AER analysis.

We find that AusNet Services opex/total inputs ratio is 3–4 per cent above the benchmark comparator-average ratio across the two periods.

The opex/total inputs ratio uses the opex and capital input quantity indexes from the index number-based MTFP analysis to construct an index that reflects the ratio of opex to total inputs.[198] As a quantity based measure, we consider it reduces some of the issues set out above of the value-based measures. However, the capital input quantity constructed may be relatively insensitive to changes in capitalisation policy with respect to overheads. In addition, we consider that, as an index-based measure, the opex/total inputs ratio may be problematic if used in quantification of the OEF adjustment. This is because the ratio is an index, comprised of two indexes (opex inputs and total inputs) rather than direct observations, as is the case for the first two ratios. Multi-lateral indexes of this type are designed with a focus on preserving comparability of productivity levels across all businesses and over time. This is enabled by doing all comparisons through the sample average (e.g. average opex across all businesses and years), rather than directly between pairs of observations. This may limit its usefulness in deriving an OEF adjustment for capitalisation under which direct comparison between pairs of observations using observation specific information is preferred. Such an application in the case of the opex/total inputs ratio

198 For each business, MTFP for each year over the 2006–2019 period is divided by opex MPFP for each year over that period. This gives the ratio of Opex/total inputs, since MTFP = Outputs/Total inputs, and Opex MPFP = Outputs/Opex.

may not be in conformance with the multi-lateral nature of the index. We will investigate this issue further as part of our further review of capitalisation.

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 7
Corporate income tax

April 2021

AUSTRALIAN
ENERGY
REGULATOR

Inquiries about this publication should be addressed to:

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AER reference: 63599

Note

This attachment forms part of the Australian Energy Regulator (AER)'s final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

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Attachment A – Negotiating framework

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7 Corporate income tax

Our distribution determination includes the estimated cost of corporate income tax for AusNet Services' 2021–26 regulatory control period. Under the post-tax framework, the cost of corporate income tax is calculated as part of the building block assessment using our post-tax revenue model (PTRM).

This attachment sets out our final decision on AusNet Services' revised proposed cost of corporate income tax for the 2021–26 regulatory control period. It presents our assessment of the inputs required in the PTRM for the calculation of the cost of corporate income tax.

7.1 Final decision

Our final decision on AusNet Services' estimated cost of corporate income tax is zero over the 2021–26 regulatory control period. This is consistent with AusNet Services' revised proposal and our draft decision.

We expect AusNet Services to incur a forecast tax loss over the 2021–26 regulatory control period.[1] We have determined that $328.6 million in tax losses as at 30 June 2026 will be carried forward to the 2026–31 regulatory control period where it can be used to offset future tax liabilities. The forecast tax loss arises because of AusNet Services' forecast tax expenses will exceed its revenue for tax assessment purposes over the 2021–26 regulatory control period. This is mostly due to the implementation of our findings from the 2018 *Review of the regulatory tax approach*, where the introduction of immediate expensing of capital expenditure (capex) and diminishing value method of tax depreciation have resulted in a significant increase of forecast tax depreciation.

For this final decision, we have:

- reduced the forecast immediately expensed capex for tax purposes from $769.6 million to $768.1 million ($2020–21)[2]
- accepted the revised proposed opening tax asset base (TAB) value as at 1 July 2021 of $3682.7 million[3]
- accepted AusNet Services' revised proposal on the standard tax asset lives for all of its asset classes, consistent with our draft decision

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1 A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to future regulatory control periods to offset future taxable income until the tax loss is fully exhausted.

2 All else equal, a lower immediately expensed capex amount will increase the cost of corporate income tax because it reduces the tax expense.

3 Subject to minor input updates for equity raising costs, weighted average cost of capital and depreciation for the 2021 half year. These changes are minor and do not have a material impact on the TAB (less than $0.01 million).

- updated AusNet Services' remaining tax asset lives as at 1 July 2021 to reflect our minor amendments to the opening TAB value
- accepted AusNet Services' revised proposal to change the tax treatment for large embedded generators by directly charging for the tax cost associated with their connections
- amended the tax treatment for gifted assets to be consistent with a recent ruling by the Full Federal Court of Australia made after the draft decision.[4]

In the draft decision, we made the following changes to AusNet Services' modelling of its cost of corporate income tax:[5]

- We revised the opening TAB as at 1 July 2021 to correct for some minor input errors in the roll forward model (RFM) for historical capex over 2016–20 regulatory control period. We also reflected AusNet Services' RAB reallocation of 'Distribution system assets' and 'Subtransmission' asset classes into the new 'Secondary systems (pre 2016)' and 'Accelerated Depr - Distr assets (Other)' asset classes and the existing 'Accelerated Depr - Distr assets (Contingent Project 3)' asset class to the TAB for these asset classes.[6]
- We revised AusNet Services' forecast immediate expensing of capex by applying an approach that is informed by AusNet Services' current immediate expensing rate.[7]
- We accepted AusNet Services' proposed standard tax asset lives. We also determined standard tax asset lives of 40 years and 5 years respectively for the two new asset classes of 'Buildings - capital works'[8] and 'In-house software'[9] that are subject to the straight-line method of tax depreciation.[10]
- While we accepted AusNet Services' proposed approach to calculating its remaining tax asset lives as at 1 July 2021, we updated these lives to reflect our adjustments to the opening TAB value. We also determined a remaining tax asset life of 2 years for the asset class of 'Accelerated depr - distr assets (contingent project 3)' and 'Accelerated depr - distr assets (other)', and determined a remaining

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4 Federal Court of Australia, *Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169*, 21 October 2020.

5 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, pp. 4–5.

6 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, pp. 17–19.

7 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, pp. 15–16.

8 This is consistent with the number of years required to completely depreciate a capital works asset such as buildings under the Income Tax Assessment Act 1997 (ITAA), ss. 43.15, 43.140 and 43.210.

9 This is consistent with the ITAA, s. 40.95(7).

10 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, p. 21.

tax asset life of 9.3 years for the asset class of 'Non-network leasehold land & buildings - 1 July 2021'.[11]

AusNet Services' revised proposal adopted the changes required by the draft decision in full.[12]

Opening tax asset base as at 1 July 2021

For this final decision, we accept AusNet Services' revised proposed opening TAB value as at 1 July 2021 of $3682.7 million ($ nominal).[13] This is $50.9 million (or 1.4 per cent) lower than the value of $3733.7 million determined in our draft decision.

In our draft decision, we accepted AusNet Services' proposed method to establish the opening TAB as at 1 July 2021. However, we amended some of the proposed inputs used for the TAB roll forward—specifically, we made adjustments for actual and estimated capex and a reallocation for accelerated tax depreciation. We noted that the opening TAB may be updated as part of the final decision to reflect:

- any revised 2020 capex estimates
- any revised capex estimates for the six month period between 1 January to 30 June 2021.

AusNet Services' revised proposal adopted our draft decision changes, and also provided the revised estimate of capex for 2020 and the half year period of 1 January to 30 June 2021.[14]

For the reasons discussed in attachment 2, we accept the updated 2020 and 2021 half year capex estimate for this final decision. The capex estimate for 2020 is lower and the capex estimate for 2021 half year is higher compared to what we approved in our draft decision, reflecting more recent data. We will update the 2020 and the six month period estimated capex for actuals at the next revenue reset (2026–31).

Table 7.1 sets out our final decision on the roll forward of AusNet Services' TAB values over the 2016–21 period.

Table 7.1 AER's final decision on AusNet Services' TAB roll forward for the 2016–21 period ($ million, nominal)

	2016	2017	2018	2019	2020[a]	2021[b]
Opening TAB	2191.8	2403.8	2649.8	2942.3	3240.1	3506.5

11 AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, pp. 19–21.

12 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal,* December 2020, pp. 130–132.

13 Subject to minor input updates for equity raising costs, weighted average cost of capital and depreciation for the 2021 half year. These changes are minor and do not have a material impact on the TAB (less than $0.01 million).

14 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal,* December 2020, p. 131.

	2016	2017	2018	2019	2020[a]	2021[b]
Capital expenditure[c]	311.7	358.2	411.9	418.7	408.8	231.4
Less: tax depreciation	99.6	112.2	119.4	120.9	142.4	82.9
Closing TAB	**2403.8**	**2649.8**	**2942.3**	**3240.1**	**3506.5**	**3682.7**

Source: AER analysis.

(a) Based on estimated capex.

(b) The half year period of 1 January to 30 June 2021. Based on estimated capex.

(c) Net of disposals.

Forecast immediate expensing of capex

For this final decision, we determine that forecast capex of $768.1 million ($2020–21) is to be immediately expensed for tax purposes in the 2021–26 regulatory control period.

In our draft decision, we amended AusNet Services' approach to forecast its immediately expensed capex. AusNet Services' proposed forecast immediate expensing of capex over the 2021–26 regulatory control period was based on a simple average of the actual immediately expensed capex claimed over 2015–2019. The proposed approach provided an immediate expensing amount that was disproportionate to overall forecast capex, as it resulted in a fixed amount irrespective of total forecast capex. We did not agree with this approach and instead considered that the forecast immediate expensing amount should be based on the rate of immediate expensing of capex relative to actual capex. We expected that the same proportion of capex would also be deducted immediately by AusNet Services for its annual tax returns during the 2021–26 regulatory control period.

AusNet Services' revised proposal adopted our draft decision approach to calculate its immediate expensing of forecast capex for tax purposes in the 2021–26 regulatory control period.[15] However, AusNet Services updated its forecast immediate expensing amount to $769.6 million ($2020–21, or 43.7 per cent of total capex),[16] which reflected its revised proposal overall forecast capex.[17]

As discussed in attachment 5, we have reduced AusNet Services' proposed forecast capex by 3 per cent.[18] Consistent with the approach adopted in the draft decision and revised proposal, we need to adjust the amount of immediate expensing of capex to reflect the overall substitute estimate of forecast capex. Our final decision therefore reduces the immediately expensed capex for tax purposes to $768.1 million ($2020–21).

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15 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal,* December 2020, pp. 136–137.

16 Compared with the proposed gross capex of $1761.6 million ($2020–21).

17 AusNet Services, *EDPR 2022–26 Revised Proposal – PTRM Model (2022–26),* December 2020.

18 AER, *Final decision: AusNet Services distribution determination 2021 to 2026, attachment 5 – Capital Expenditure*, April 2021, p. 5.

We will collect actual data relating to the immediately expensing of capex in our annual reporting regulatory information notices to further inform our decision for this type of expenditure in the next regulatory determination for AusNet Services.

Treatment of gifted assets

For this final decision, we have changed the tax treatment of gifted assets for AusNet Services. We have therefore excluded the value of gifted assets from the cash flow modelling in the PTRM for the purposes of calculating the corporate income tax building block.

In our draft decision, we applied the usual treatment as adopted by the Australian Taxation Office where gifted assets (along with cash customer contributions) were included as assessable income in the cash flow modelling in the PTRM.

On 21 October 2020, the Full Federal Court of Australia published its determination on the tax treatment of customer contributions.[19] The determination:

- Confirmed an earlier Court ruling that cash contributions were ordinary income and should be treated as assessable income for tax purposes.
- Overturned an earlier Court ruling and determined that while a gifted asset was a 'non-cash business benefit' there was effectively nil income for tax purposes.

We consider the Court's ruling on gifted assets require us to change the tax treatment in our cash flow modelling in the PTRM. As such, the cost of construction of these assets has to be removed from AusNet Services' revised proposed gross capex and customer contributions.[20] While this results in no change to net capex, this tax treatment change results in a decrease to the cost of corporate income tax building block. AusNet Services submitted its revised gross capex and customer contributions in response to our information request to exclude the value of gifted assets.[21] The impact of this change in approach for gifted assets will increase AusNet Services' forecast tax loss, all else being equal.

We have assessed AusNet Services' revisions and are satisfied that it implements the Court's ruling on the tax treatment of gifted assets.

Tax treatment for embedded generators

AusNet Services' revised proposal submitted that large embedded generators connecting to its distribution network should now be charged directly for the tax costs associated with their connection.[22] Currently, these tax costs are borne by all

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19 Federal Court of Australia, *Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169*, 21 October 2020.

20 Any associated rebates would remain being included in net capex and therefore treated as a tax depreciating asset.

21 AusNet Services, *Response to AER Information Request #084*, 10 March 2021.

22 AusNet Services, *EDPR 2022–26 Revised Regulatory Proposal,* 03 December 2020, pp. 140–141.

customers using standard control services. For the reasons discussed in attachment 18, we accept AusNet Services' revised proposal to change the tax treatment for large embedded generator connections because it has consulted on this change from the initial proposal. For AusNet Services' final decision PTRM we have therefore excluded the capex for these connections from the input sections for both gross capex and capital contributions. This change will lower the calculated revenue for tax assessment, and as a result increases the size of AusNet Services' forecast tax loss at 30 June 2026.

Standard and remaining tax asset lives

For this final decision, we accept AusNet Services' revised proposed standard tax asset lives for all of its asset classes. They are consistent with our draft decision, and we confirm our position that the standard asset lives are broadly consistent with the values prescribed by the Commissioner for taxation in the Australian Tax Office ruling 2020/3 and the Income Tax Assessment Act 1997 (ITAA).

We also accept AusNet Services' revised proposed approach to calculate the remaining tax asset lives as at 1 July 2021 for tax depreciation purposes of its existing assets, which were calculated using the weighted average method.[23] This is consistent with the approach accepted in our draft decision. However, we have updated the remaining tax asset lives as at 1 July 2021 to reflect the amendments we made to the opening TAB values as at 1 July 2021.[24]

Table 7.2 sets out our final decision on the standard and remaining tax asset lives as at 1 July 2021 for AusNet Services. We are satisfied that the standard and remaining tax asset lives are appropriate for application over the 2021–26 regulatory control period. We are also satisfied that the standard and remaining tax asset lives provide an estimate of the tax depreciation amount that would be consistent with the tax expenses used to estimate the annual taxable income for a benchmark efficient service provider.[25]

Table 7.2 AER's final decision on AusNet Services' standard and remaining tax asset lives (years)

Asset class	Standard tax asset life	Remaining tax asset lives as at 1 July 2021[b]
Subtransmission	43.0	36.1
Distribution system assets	46.0	34.9

23 The proposed method is a continuation of the approved approach used in the 2016–20 regulatory control period and applies the approach as set out in our RFM.

24 The estimates of 2020 and 2021 capex are used to calculate the weighted average remaining tax asset lives in the RFM. Therefore, for this final decision we have recalculated AusNet Services' remaining tax asset lives as at 1 July 2021 reflecting the updates for the estimates of 2020 and 2021 capex, using the method approved in the draft decision.

25 National Electricity Rules, cl. 6.5.3.

Asset class	Standard tax asset life	Remaining tax asset lives as at 1 July 2021[b]
SCADA/Network control	10.0	8.3
Non-network general assets - IT	4.0	3.2
Non-network general assets - Other	12.0	7.2
Land	n/a	n/a
Secondary systems (pre 2016)	n/a	5.3
Accelerated depr - Distr assets (contingent project 3)	n/a	2.0
Accelerated depr - Distr assets (other)	n/a	2.0
Non-network leasehold land & buildings – 1 July 2021	n/a	9.3
Non-network leasehold land & buildings – 2021–22	23.7	n/a
Non-network leasehold land & buildings – 2025–26	5.0	n/a
Buildings - capital works	40.0[a]	n/a
In-house software	5.0[a]	n/a
Equity raising costs	5.0[a]	3.1

Source: AER analysis.

(a) These are the only asset classes used for the straight-line method of tax depreciation for new assets. All new assets for other asset classes used the diminishing value method of tax depreciation.

(b) Used for straight-line method of tax depreciation.

n/a not applicable. We have not assigned a standard tax asset life and remaining tax asset life to the 'Land' asset class because the assets allocated to it are non-depreciating assets. We have not assigned a standard tax asset life to the ‘Secondary systems (pre 2016)’, 'Accelerated depr - Distr assets (contingent project 3)', 'Accelerated depr - Distr assets (other)' and ‘Non-network leasehold land & buildings - 1 July 2021’ and asset classes, because there are no new capex being allocated to these asset classes in the future. We also have not assigned a remaining tax asset life to the ‘Non-network leasehold land & buildings – 2021–22’, ‘Non-network leasehold land & buildings – 2025–26’, 'Buildings - capital works' and 'In-house software' asset classes because they have no opening TAB values as at 1 July 2021.

7.2 Assessment approach

We did not change our assessment approach for the cost of corporate income tax from our draft decision. Attachment 7 (section 7.3) of our draft decision details that approach.[26]

[26] AER, *Draft decision: AusNet Services distribution determination 2021 to 2026, attachment 7 – Corporate Income Tax*, September 2020, pp. 7–14.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	capital expenditure
ITAA	Income Tax Assessment Act 1997
PTRM	post-tax revenue model
RFM	roll forward model
TAB	tax asset base

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 8
Efficiency benefit sharing scheme

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

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Attachment A – Negotiating framework

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8 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) is intended to provide a continuous incentive for distributors to pursue efficiency improvements in operating expenditure (opex), and provide for a fair sharing of these between distributors and network users. Consumers benefit from improved efficiencies through lower opex allowances in subsequent regulatory control periods.

This attachment sets out our final decision on the EBSS carryover amounts AusNet Services accrued over the 2016–20 regulatory control period, and how we will apply the EBSS over the 2021–26 regulatory control period.

8.1 Final decision

8.1.1 EBSS carryover amounts

Our final decision is to approve EBSS carryover amounts totalling $109.3 million ($2020–21) from the application of the EBSS in the 2016–20 regulatory control period.[1] This is the same as AusNet Services' revised proposal of $109.3 million ($2020–21),[2] which is consistent with our draft decision. The minor differences in EBSS carryovers in HY2021, 2023–24 and 2025–26 are due to updating for actual inflation and forecast inflation for the year to June 2021 using the latest Reserve Bank of Australia's (RBA) February 2021 *Statement on monetary policy.*[3]

We set out our final decision on AusNet Services' EBSS carryover amounts in table 8.1.

Table 8.1 Final decision on carryover amounts ($ million, 2020–21)

	HY2021	2021–22	2022–23	2023–24	2024–25	2025–26	Total
AusNet Services revised proposal	12.5	55.2	36.3	15.4	–4.0	–6.2	**109.3**
AER final decision	12.5	55.2	36.3	15.4	–4.0	–6.2	**109.3**
Difference	0.0	–	–	–	–0.0	–0.0	**–**

Source: AusNet Services, *2021–26 Revised Regulatory Proposal*, December 2020, p. 148; AER analysis.

Note: Numbers may not add up due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

1 NER, cl. 6.4.3(a)(5).

2 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 148.

3 Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

8.1.2 Application in the 2021–26 control period

Our final decision is to apply version two of the EBSS to AusNet Services for the 2021–26 regulatory control period.[4] Consistent with AusNet Services' revised proposal and our draft decision we will exclude guaranteed service levels (GSL) payments, innovation program costs and debt-raising costs from the scheme.[5] We will also make other adjustments as permitted by the EBSS, such as removing demand management innovation allowance costs, and movement in provisions (as outlined in section 8.4)

We have set out in table 8.2 the opex forecasts we will use to calculate efficiency gains in the 2021–26 regulatory control period, including forecast debt raising costs.[6]

Table 8.2 Forecast opex for the EBSS ($ million, 2020–21)

	2019	2020	HY2021	2021–22	2022–23	2023–24	2024–25	2025–26
Total forecast opex	260.2	266.3	135.7	240.1	243.4	247.1	251.4	256.7
Less GSL payments	–9.0	–9.0	–4.5	–9.5	–9.3	–9.2	–9.0	–8.9
Less innovation program	–	–	–	–0.2	–0.2	–0.2	–0.2	–0.2
Less debt raising costs	–2.2	–2.4	–1.2	–2.2	–2.2	–2.3	–2.3	–2.3
Forecast opex for the EBSS	**249.0**	**254.9**	**130.0**	**228.2**	**231.6**	**235.4**	**239.8**	**245.2**

Source: AER, *Final decision, AusNet Services distribution determination 2021–26, PTRM*, April 2021; AER, *Final decision, AusNet Services distribution determination 2021–26, EBSS model, April 2021*; AER analysis.

Note: Numbers may not add up due to rounding.

8.2 AusNet Services' revised proposal

8.2.1 Carryover amounts from the 2016–20 regulatory control period

AusNet Services accepted our draft decision on the EBSS carryovers accrued from the application of the EBSS in the 2016–20 regulatory control period in its revised regulatory proposal. It made no updates to the amounts we calculated.[7]

8.2.2 Application in the 2021–26 regulatory control period

AusNet Services accepted our draft decision to apply the EBSS in the 2021–26 regulatory control period.[8]

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4 NER, cl. 6.12.1(9); AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

5 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, pp. 148–149.

6 Subject to other adjustments required by the EBSS.

7 AusNet Services, *Revised regulatory proposal 2021–26*, December 2020, p. 148.

8.2.3 Stakeholder submissions

We received three submissions relating to the EBSS. They all focused on the effectiveness of all the incentive schemes (including Capital Expenditure Sharing Scheme (CESS) and Service Target Performance Incentive Scheme (STPIS)) and whether a broader review was required to ensure they were operating as intended.

Victorian Community Organisations (VCO) consider the EBSS is insufficient to drive opex to the efficient frontier. They noted that the productivity of distributors has not matched or exceeded economy wide productivity increases and often distributor productivity has been negative.[9]

The Consumer Challenge Panel, sub-panel 17 (CCP17), questioned the effectiveness of the EBSS and CESS and strongly supported a broad review of these incentive schemes. It urged the AER to assign a high priority to this work program in 2021.[10]

Origin Energy questioned whether expenditure underspends represented genuine efficiency gains and if the incentive schemes were operating as intended. Origin Energy also supported the review of our incentive schemes.[11]

In our draft decisions for CitiPower, Powercor and United Energy, we announced a broad review of incentive schemes to address stakeholder concerns.[12] We reaffirmed our plan to undertake an incentive review as part of our 2020–25 strategic plan. As part of our priorities to deliver efficient regulation of monopoly infrastructure, we will review and refine our incentive schemes to ensure they remain relevant and fit for purpose.[13]

8.3 Assessment approach

Under the National Electricity Rules (NER) we must determine:

- the revenue increments or decrements for each year of the 2021–26 regulatory control period arising from the application of the EBSS during the 2016–20 regulatory control period[14]
- how the EBSS will apply to AusNet Services in the 2021–26 regulatory control period.[15]

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8 AusNet Services, *Revised regulatory proposal 2021–26,* December 2020, p. 149.

9 VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 57–58.

10 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 68.

11 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 1–2.

12 AER, *Draft decision, CitiPower distribution determination 2021–26, Overview*, September 2020, p. 5; AER, *Draft decision, Powercor distribution determination 2021–26, Overview*, September 2020, p. 6.; AER, *Draft decision, United Energy distribution determination 2021–26, Overview*, September 2020, p. 5.

13 AER. *Strategic plan 2020–2025*, December 2020, p. 18.

14 NER, cl. 6.4.3(a)(5).

15 NER, cl. 6.3.2(a)(3); cl. 6.12.1(9).

The EBSS must provide for a fair sharing of opex efficiency gains and efficiency losses between service providers and network users.[16] We must also have regard to the following matters when implementing the EBSS:[17]

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
- the need to provide AusNet Services with a continuous incentive to reduce opex
- the desirability of both rewarding AusNet Services for efficiency gains and penalising it for efficiency losses
- any incentives that AusNet Services may have to capitalise expenditure
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

8.3.1 Interrelationships

The EBSS is closely linked to our revealed cost approach to forecasting opex. When we assess or develop our opex forecast, the NER require us to have regard to whether the opex forecast is consistent with any incentive schemes.[18]

Our opex forecasting method typically relies on using the 'revealed costs' of the service provider in a chosen base year to develop a total opex forecast if the chosen base year opex is not considered to be 'materially inefficient'. Under this approach, a service provider would have an incentive to spend more opex in the expected base year. Also, a service provider has less incentive to reduce opex towards the end of the regulatory control period, where the benefit of any efficiency gains is retained for less time.

The application of the EBSS serves two important functions:

1. It removes the incentive for a service provider to inflate opex in the expected base year in order to gain a higher opex forecast for the next regulatory control period.
2. It provides a continuous incentive for a service provider to pursue efficiency improvements across the regulatory control period.

The EBSS does this by allowing a service provider to retain efficiency gains (or losses) for a total of six years, regardless of the year in which the service provider makes them. Where we do not propose to rely on the single year revealed costs of a service provider in forecasting opex, this has consequences for the service provider's incentives and our decision on how we apply the EBSS.

When a distributor makes an incremental efficiency gain, it receives a reward through the EBSS, and consumers benefit through a lower revealed cost forecast for the

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16 NER, cl. 6.5.8(a).

17 NER, cl. 6.5.8(c).

18 NER, cl. 6.5.6(e)(8). Further, we must specify and have regard to the relationship between the constituent components of our overall decision: National Electricity Law, s. 16(1)(c).

subsequent regulatory control period. This is how efficiency improvements are shared between consumers and the distributor. If we subject costs to the EBSS that are not forecast using a revealed cost approach, a distributor would in theory receive a reward for efficiency gains through the EBSS (at a cost to consumers), but consumers would not benefit through a lower revealed cost forecast in the subsequent regulatory control period.

Therefore, we typically exclude costs that we do not forecast using a single year revealed cost forecasting approach.

For these reasons, our decision on how we will apply the EBSS to AusNet Services has a strong interrelationship with our decision on its opex (see Attachment 6 – Operating expenditure). We have careful regard to the effect of our EBSS decision when making our opex decision, and our EBSS decision is made largely in consequence of (and takes careful account of) our past and current decisions on AusNet Services' opex.

8.4 Reasons for final decision

8.4.1 Carryover amounts from the 2016–20 regulatory control period

AusNet Services addressed each of the issues we identified in our draft decision and adopted the same approach to calculate the EBSS carryover in its revised regulatory proposal as we used in our draft decision.[19] This includes our proposed treatment of the new accounting standard AASB 16 as a non-recurrent efficiency adjustment.[20] The only change we have made to AusNet Services' revised proposal is to update actual inflation in the year to December 2020 and forecast inflation for the year to June 2021 using the RBA's February 2021 *Statement on monetary policy*.[21]

We consider that the EBSS carryover amounts we have calculated, as set out in table 8.1, provide for a fair sharing of efficiency gains and losses between AusNet Services and its network users. It both rewards AusNet Services for the efficiency gains it has made and penalises it for its efficiency losses. Further, we consider that the benefit to networks users, through lower forecast opex, is sufficient to warrant the EBSS carryover amounts we have determined.

8.4.1.1 2020 and half year 2021 EBSS carryovers

As outlined in our six month extension guidance, we have deferred the payment of the half year 2021 EBSS carryover amount until 2021–22.[22] Our calculation uses the half

[19] AusNet Services, *2021–26 Revised regulatory proposal,* December 2020, p. 148.

[20] AER, *Draft decision, AusNet Services distribution determination 2021–26, Attachment 8, Efficiency benefit sharing scheme, September 2020*, pp. 11–12.

[21] Reserve Bank of Australia, *Statement on monetary policy*, February 2021.

[22] AER, *Correspondence to AusNet Services – Victorian EDPR and the six-month extension*, 17 August 2020, p. 4.

year 2021 weight average cost of capital (WACC) and first year WACC of the 2021–26 regulatory control period to determine the present value equivalent amount, which we have included in revenues for 2021–22.

Due to the six month extension, we have also modified our standard formulae in the EBSS model[23] to ensure the incremental gains or losses accrued in calendar year 2020 and half year 2021 are carried forward for five years as intended by our decision for the 2016–20 regulatory control period.[24]

8.4.2 Application in the 2021–26 regulatory control period

Our final decision is to continue to apply version 2 of the EBSS to AusNet Services during the 2021–26 regulatory control period. We consider applying the scheme will benefit long-term electricity customers by providing continuous incentives for AusNet Services to reduce opex. Provided that we forecast AusNet Services' future opex using its revealed costs in the 2021–26 regulatory control period, any efficiency gains that AusNet Services achieves will lead to lower opex forecasts, and thus lower network tariffs.

Version 2 of the EBSS specifies our approach to determining the length of the carryover period and adjusting forecast or actual opex when calculating carryover amounts.[25] We provide details on these below.

8.4.2.1 Length of carryover period

To ensure continuous incentives, the length of the carryover period for the 2021–26 regulatory control period will be the same as the length of AusNet Services' following regulatory control period.[26] This ensures that any gains or losses are retained by AusNet Services for the same length of time (usually five years) regardless of the year in which they are achieved. AusNet Services' following regulatory control period is expected to be five years, starting from 1 July 2026.

8.4.2.2 Adjustments to forecast or actual opex

The EBSS allows us to exclude categories of costs that we do not forecast using a single year revealed cost forecasting approach. We do this to fairly share efficiency gains and losses.

Consistent with version 2 of the EBSS, we will exclude GSL payments, innovation program costs and debt raising costs from the EBSS. This is because we do not forecast these costs on a single year revealed cost basis. We instead forecast GSL payments based on an historic average, not a single year. The category specific

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23 See rows 54, 71 and 72 of the EBSS model.

24 The Order in Council made on 27 October 2020 under section 16VE of the National Electricity (Victoria) Act 2005 allows for such modifications.

25 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013.

26 NER, cl. 6.5.8(c)(2).

forecast for innovation is a set allowance and debt raising costs are based on a benchmark amount.

In addition we will also make the following adjustments when we calculate the EBSS carryover amounts for the next regulatory control period:

- adjust forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination, such as approved pass through amounts or opex for contingent projects[27]
- adjust actual opex to remove demand management innovation allowance opex because it is not included in the opex forecast (but is often reported by service providers as part of their standard control services opex)[28]
- adjust actual opex to add capitalised opex that has been excluded from the regulatory asset base[29]
- adjust forecast opex and actual opex for inflation[30]
- adjust actual opex to reverse any movements in provisions
- adjust opex for any services that will not be classified as standard control services in the 2026–31 regulatory control period, to the extent these costs are not forecast using a single year revealed cost approach and excluding these costs better achieves the requirements of clauses 6.5.8 of the NER.[31]

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27 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013, p. 7.

28 Clause 6.5.8(c)(5) of the NER requires us to have regard to the possible effects of the scheme on incentives for the implementation of non-network options.

29 Clause 6.5.8(c)(4) of the NER requires us to have regard to any incentives the service provider may have to capitalise expenditure.

30 AER, *Efficiency benefit sharing scheme for electricity network service providers*, November 2013, p. 7.

31 AER, *Explanatory Statement: Efficiency benefit sharing scheme for electricity network service providers,* November 2013, p. 14.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
distributor	distribution network service provider
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	Capital Expenditure Sharing Scheme
EBSS	efficiency benefit sharing scheme
GSL	guaranteed service levels
NER	National Electricity Rules
opex	operating expenditure
RBA	Reserve Bank of Australia
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 9 Capital expenditure sharing scheme

April 2021

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AER reference: 63599

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

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9 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capital expenditure (capex) becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between service providers and consumers.

The CESS works as follows:

- We calculate the cumulative efficiency gains or losses for the current regulatory control period in net present value terms.
- We apply the sharing ratio of 30 per cent to the cumulative underspend or overspend to work out what the service provider's share of the underspend or overspend should be.
- We calculate the CESS payments taking into account the financing benefit or cost to the service provider of the underspend or overspend.[1] We can also make further adjustments to account for deferral of capex and *ex post* exclusions of capex from the regulatory asset base (RAB).[2]
- The CESS payments will be added or subtracted to the service provider's regulated revenue as a separate building block in the next regulatory control period.

We consider in addition to greater incentives to improve capex efficiency, the CESS provides a consistent incentive to incur capex efficiently during a regulatory control period and encourages more efficient substitution between capex and operating expenditure (opex).

This attachment sets out our final decision for the determination of the revenue impacts as a result of the CESS applying from the 2016–20 regulatory control period and the application of the CESS for AusNet Services in the 2021–26 regulatory control period.

1 We calculate benefits as the benefits to the service provider of financing an underspend since the amount of the underspend can be put to some other income generating use during the period. Losses are similarly calculated as the financing cost to the service provider of the overspend.

2 The capex incentive guideline outlines how we may exclude capex from the RAB and adjust the CESS payment for deferrals. AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, pp. 9, 13–20.

9.1 Final decision

Revenue impact for the 2021–26 regulatory control period

Our final decision is to apply a CESS revenue increment amount of $73.8 million ($2020–21) to be paid across the 2021–26 regulatory control period, from the application of the CESS in the 2016–20 regulatory control period.

The difference between our final decision and AusNet Services' revised proposal ($72.6 million) is due to adopting:

- more recent inflation figures
- updated weighted average cost of capital (WACC) input information
- updated 2020 capex consistent with our roll forward model.

Application of scheme in 2021–26 regulatory control period

We will apply the CESS to AusNet Services in the 2021–26 regulatory control period, as set out in the capital expenditure incentives guideline.[3] This is consistent with the proposed approach we set out in our framework and approach paper.[4]

The reasons for adopting a CESS is set out in our capital expenditure incentive guideline.[5]

9.2 AusNet Services' revised proposal

AusNet Services proposed a $72.6 million ($2020–21) CESS revenue increment for the 2021–26 regulatory control period. AusNet Services updated its CESS increment for actual capex in the 2020 regulatory control year. AusNet Services identified a decrease in its 2020 capex as result of COVID-19. It also included a CESS deferral adjustment of $4.5 million to reflect deferred capex for its Kalkallo project.[6]

9.3 Assessment approach

Under the National Electricity Rules (NER) we must decide:

- the revenue effects on AusNet Services arising from applying the CESS in the 2016–20 regulatory control period; and

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3 NER, cl 6.12.1(9); AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, pp. 5–9.

4 AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory control period commencing 1 January 2021*, January 2019, pp. 84–85.

5 AER, *Better regulation explanatory statement capital expenditure incentive guideline for electricity network service providers*, November 2013.

6 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 150.

- whether to apply the CESS to AusNet Services in the 2021–26 regulatory control period[7] and how any applicable scheme will apply.[8]

Our assessment approach is set out below.

We must determine the appropriate revenue increments or decrements (if any) for each year of the 2021–26 regulatory control period arising from the application of the CESS during the 2016–20 regulatory control period.[9] This includes assessing whether any adjustments should be made to the CESS for deferred capex.

Consistent with the CESS, we will make an adjustment to CESS payments where a distributor has deferred capex in the current regulatory control period and:

- the amount of the deferred capex in the current regulatory control period is material; and
- the amount of the estimated underspend in capex in the current regulatory control period is material; and
- total approved capex in the next regulatory control period is materially higher than it is likely to have been if a material amount of capex was not deferred in the current regulatory control period.[10]

The NER require that our final decision include a determination concerning how any applicable CESS should apply to AusNet Services.[11] In deciding whether to apply a CESS to AusNet Services for the 2021–26 regulatory control period, and the nature of the details of the scheme that is to apply, we must:

- make that decision in a manner that contributes to the capex incentive objective;[12] and
- take into account the CESS principles,[13] the capex objectives and (if relevant) the opex objectives,[14] the interaction with other incentive schemes[15] as they apply to the particular service provider, and the circumstances of the service provider.[16]

The capex incentive objective is to ensure that only capex that meets the capex criteria enters the RAB used to set prices. Therefore, consumers only fund capex that is efficient and prudent.

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7 NER, cl. 6.5.8A(e).

8 NER, cl. 6.12.1(9).

9 NER, cl. 6.4.3(a).

10 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 9.

11 NER, cl. 6.12.1(9).

12 NER, cl. 6.5.8A(e)(3); the capex incentive objective is set out in cl. 6.4A(a) of the NER.

13 NER, cl. 6.5.8A(e)(4)(i); the CESS principles are set out in cl.6.5.8A(c).

14 NER, cll. 6.5.8A(e)(4)(i) and 6.5.8A(d)(2); the capex objectives are set out in cl. 6.5.7(a); the opex objectives are set out in cl.6.5.6(a).

15 NER, cll. 6.5.8A(e)(4)(i) and 6.5.8A(d)(1).

16 NER, cl. 6.5.8A(e)(4)(ii).

9.4 Reasons for final decision

We have not adjusted AusNet Services' CESS revenue increment to account for any further material deferrals.

However, we have adjusted the modelling inputs such as the Consumer Price Index, reported capex and the WACC to reflect more up to date information. These adjustments reflect modelling updates to the roll forward model.

In our draft decision, we did not identify any material deferrals included in AusNet Services' forecast capex. AusNet Services updated its 2020 capex and identified deferred capex for its Kalkallo Rapid Earth Fault Current Limiterproject from the current regulatory control period into the forecast regulatory control period. To account for this, AusNet Services included $14.5 million of deferred capex into its CESS model. This reduced its CESS benefit by $4.5 million.[17]

We received several submissions regarding the CESS.

In its report to Energy Consumers Australia (ECA), Spencer&Co noted that the CESS must reward efficient behaviour only, not failure to deliver projects.[18]

The Consumer Challenge Panel, sub-panel 17 (CCP17) raised concerns with the outcomes of the CESS and strongly supported the incentive review in 2021.[19]

The Energy Users Association of Australia (EUAA) identified several limitations of the CESS scheme. In particular, the EUAA noted there was no incentive to overspend, so deferred projects are unlikely to be completed next period. The EUAA was not convinced that this reflects the original intent of the scheme, and considered that it is easy to game.[20]

The Victorian Community Organisations welcomed the incentive scheme review and identified several issues that should be considered as part of the review.[21]

We note that if a distributor can maintain its service standards without undertaking additional capex, consumers will benefit from this through a lower RAB. As long as deferred capex is not included in our forecast capex, then we are satisfied consumers are not paying additional costs for deferring projects. This means consumers pay lower prices than would have been the case in the absence of the CESS.

17 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 150.

18 ECA, Spencer&Co report, *Submission and attachment on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 19.

19 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, p. 68.

20 EUAA, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 9–10.

21 Victorian Community Organisations, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 27; Victorian Community Organisations, Headberry Partners, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 - Report to Sponsoring Organisations*, January 2021, pp. 58–59.

In our draft decision, we announced an incentive review to address stakeholder concerns regarding the CESS. We reaffirmed our plan to undertake an incentive review as part of our 2020–25 strategic plan. As part of our priorities to delivery efficient regulation of monopoly infrastructure, we will review and refine our incentive schemes to ensure they remain relevant and fit for purpose.[22]

22 AER, *Strategic Plan 2020–25*, December 2020, p. 18.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
Capex	Capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	Capital Expenditure Sharing Scheme
Distributor	Distribution Network Service Provider
ECA	Energy Consumers Australia
EUAA	Energy Users Association of Australia
NEO	National Electricity Objective
NER	National Electricity Rules
Opex	Operating expenditure
RAB	Regulatory Asset Base
WACC	Weighted Average Cost of Capital

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 10
Service target performance incentive scheme

July 2021

AUSTRALIAN
ENERGY
REGULATOR

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Amendment table

Update	Date	Page
Revocation and substitution to correct for Beta method error.	9 July 2021	10-4, 10-11

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

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10 Service target performance incentive scheme

Under clauses 6.3.2 and 6.12.1(9) of the National Electricity Rules (NER) our regulatory determination must specify how any applicable service target performance incentive scheme (STPIS) is to apply in the next regulatory control period.

This attachment sets out our final decision on how we will apply the STPIS version 2.0 to AusNet Services for the 2021–26 regulatory control period.

AER's service target performance incentive scheme

We published the current version (version 2.0) of our national STPIS in November 2018.[1] The STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives to distributors to maintain and improve service performance where customers are willing to pay for these improvements.

Our draft decision on the application of STPIS

Our draft decision for AusNet Services was to apply the STPIS version 2.0.[2]

For the 2021–26 regulatory control period we proposed to:

- set revenue at risk at ± 5 per cent
- segment the network according to the urban and short feeder categories
- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and Momentary Average Interruption Frequency Index (MAIFI) and customer service (telephone answering) parameters
- set performance targets based on the distributor's average performance over the past five regulatory control years
- not apply the telephone answering parameter in the STPIS as AusNet Services opted to apply the new Customer Service Incentive Scheme (CSIS)
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets and 2.8 beta method to calculate the major event day
- apply the method and values of customer reliability (VCR) as indicated in our Values of Customer Reliability Review published in December 2019[3]

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1 AER, *Electricity distribution network service providers—service target performance incentive scheme version 2.0*, November 2018.

2 AER, *Draft Decision AusNet Services Distribution Determination 2021 to 2026, Attachment 10 Service target performance incentive scheme*, September 2020; AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, p. 76.

- not apply the guaranteed service level (GSL) component of the STIPS, as the Victorian distributors remain subject to a jurisdictional GSL scheme.[4]

10.1 Final decision

Our final decision is to apply the STPIS 2.0 to AusNet Services for the 2021–26 regulatory control period.

We will not apply the STPIS telephone answering target and incentive rate to AusNet Services in the next regulatory control period because the distributor has opted to apply the CSIS. The revenue at risk for the STPIS has also been adjusted to reflect the removal of the telephone answering parameter. That said, AusNet Services will continue to report on the telephone answering parameter in the upcoming regulatory control period via the STPIS.

We have taken into account AusNet Services' revised revenue proposal, submissions raised by stakeholders and our draft decision and the Framework and Approach paper in reaching our final decision.[5] Our response to the matters raised by AusNet Services and stakeholders about the application of STPIS is below.

Table 10.1 and Table 10.2 present our final decision on the applicable incentive rates and targets that will apply to AusNet Services for the 2021–26 regulatory control period.

Table 10.1 Final decision – STPIS incentive rates for AusNet Services for the 2021–26 regulatory control period

Incentive rates	Urban	Short rural	Long rural
SAIDI	0.02269	0.02160	0.00924
SAIFI	1.48003	1.40017	0.68878
MAIFI	0.11840	0.11201	0.05510

Source: AER analysis.

3 AER, *Values of Customer Reliability Review - Final Report*, December 2019.

4 AER. *Draft Decision AusNet Services Distribution Determination 2021 to 2026 Attachment 10 Service target performance incentive scheme, September 2020*; AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, p. 76.

5 AusNet Electricity Services, *Electricity Distribution Price Review 2022–26, Revised Regulatory Proposal,* December 2020, p. 145.

Table 10.2 Final decision—STPIS reliability targets for AusNet Services for the 2021–26 regulatory control period

Performance targets	value
Urban	
SAIDI	87.190
SAIFI	0.891
MAIFI	2.817
Short rural	
SAIDI	195.160
SAIFI	2.007
MAIFI	5.657
Long rural	
SAIDI	293.692
SAIFI	2.628
MAIFI	9.920

Source: AER analysis.

10.2 AusNet Services' revised revenue proposal

AusNet Services' revised revenue proposal accepted our draft decision on how STPIS will apply and also submitted the latest reliability data to be included in this final decision.[6] AusNet Services will apply the CSIS in the next regulatory control period.

10.3 Assessment approach

We are required to make a decision on how the STPIS is to apply to AusNet Services.[7] When making a distribution determination, the STPIS requires us to determine all performance targets, incentive rates, revenue at risk and other parameters under the scheme.[8]

We outlined our proposed approach to, and reasons for, the application of the STPIS in our framework and approach and draft decision for AusNet Services. Our final decision

6 AusNet Electricity Services, *Electricity Distribution Price Review 2022–26 Revised Regulatory Proposal,* December 2020, p. 145.

7 NER, cl. 6.12.1(9).

8 AER, *STPIS*, November 2018, cl. 2.1(d).

has adopted the position in the draft decision and have taken into account the materials submitted to us by AusNet Services and stakeholders.

10.3.1 Interrelationships

In implementing the STPIS, we must take into account any other incentives available to the distributor under the NER or relevant distribution determination.[9] One of the objectives of the STPIS is to ensure that the incentives are sufficient to offset any financial incentives the distributor may have to reduce costs at the expense of service levels. For the 2021–26 regulatory control period, the STPIS will interact with the Capital Expenditure Sharing Scheme (CESS) and the operating expenditure (opex) Efficiency Benefit Sharing Scheme (EBSS).

The reward and penalty mechanism, under the STPIS (the incentive rates) are determined based on the average customer value for the improvement, or otherwise, to supply reliability (the VCR). This is aimed at ensuring that the distributor's operational and investment strategies are consistent with customers' value for the services that are offered to them.

Our capital expenditure (capex) and opex allowances are set to reasonably reflect the expenditures required by a prudent and efficient business to achieve the capex and opex objectives. These include complying with all applicable regulatory obligations and requirements and, in the absence of such obligations, maintaining quality, reliability, and security outcomes.

The STPIS provides an incentive for distributors to invest in further reliability improvements (via additional STPIS rewards) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

In conjunction with the CESS and EBSS, the STPIS will ensure that:

- any additional investments to improve reliability are based on prudent economic decisions
- any reduction in capex and opex are achieved efficiently, rather than at the expense of service levels to customers,

10.4 Submissions

The Consumer Challenge Panel, sub-panel 17 (CCP17) supported the introduction of the CSIS for AusNet Services, CitiPower, Powercor and United Energy for the 2021–26 regulatory control period, and Jemena's choice not to adopt a CSIS in that

9 NER, cl. 6.6.2(b)(3)(iv).

regulatory period.[10] The CCP17 also supported our draft decision on STPIS that AusNet Services should continue to report on the telephone answering parameter in the upcoming regulatory control period for transparency purposes.[11]

As discussed above, AusNet Services will apply the CSIS but is required to report on the telephone answering parameter in the next regulatory control period.

We received submissions about distributors historical under-spend on capex and opex allowances, as well as customers' willingness to pay for reliability improvements.

Red Energy/Lumo Energy submitted that it did not support any of the resubmissions that apply to the incentive schemes other than the CESS and EBSS. It stated that the STPIS is not required to be applied to AusNet Services, because:[12]

> The STPIS was introduced to address the risk that DNSPs would under-spend relative to their benchmark expenditure allowances over the regulatory period improving their profitability at the expense of reliability. In our view, it is not clear that a DNSP would erode the reliability of its network for short term profits. Such a strategy would risk the loss of its license in the long run.

The joint submission from the Victorian Community Organisations stated that:[13]

> In its response to the initial proposals the sponsors, (i.e. Victorian Community Organisations) noted that the current version of the STPIS (version 2.0) has some shortcomings, particularly that
>
> - There was a continual reliability improvement which, because consumers were paying the DBs a bonus, they are effectively paying for improved reliability.
> - There is an unwillingness to pay for increased reliability.
> - The STPIS targets for the next period are based on performance that was achieved well into the past and a rolling average target based on the previous 3-4 years is a better incentive for performance and provides a better outcome for consumers.
>
> The AER draft decision states that the current STPIS (version 2.0) is to be applied to the next regulatory period without change, meaning that the current detriments observed will continue. This is disappointing.
>
> The AER also observes that the unwillingness to pay for increased reliability is addressed within the Value of Customer Reliability (VCR). While the provision

[10] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 96–97.

[11] CCP17, CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* January 2021, pp. 96–97.

[12] Red Energy / Lumo Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3-4.

[13] Victorian Community Organisation, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26 – Headberry Partners - Report to the Sponsoring Organisations*, January 2021, p. 59.

> of the VCR does provide guidance as to the willingness of consumers to pay it is pointed out that consumers have been quite clear that they do not want to pay at all for improved reliability so the application of the VCR should refer more to the price consumers are prepared to pay for maintaining or avoiding reductions in reliability rather than them paying to further increase reliability.
>
> The AER also commented that it does not consider that there is a relationship between reliability of supply and the development of the opex and capex allowances as any proposal by the DBs to improve reliability has to demonstrate a clear relationship between the cost of the improvement and the change in reliability to be achieved. This is not the point.
>
> The commentary by the sponsors was that the amount of capex and opex do have a relationship with the reliability achieved and if the opex and capex allowance is higher than needed to maintain reliability then there will be improved reliability. Effectively, if reliability is improving over time, then it is because the AER has provided more capex and opex than were needed. This is what is being observed – that reliability is improving implying that the opex and capex allowances are higher than necessary.
>
> With this in mind, the allowances for opex and capex should include recognition of the trend of reliability performance.

We would like to clarify that the STPIS provides an incentive for distributors to invest in further reliability improvements (via additional STPIS rewards) where customers are willing to pay for it. Conversely, the STPIS penalises distributors where they let reliability deteriorate. Importantly, the distributor will only receive a financial reward after actual improvements are delivered to the customers.

More importantly, a distributor can only retain its rewards if it can maintain the reliability improvements on an ongoing basis. Once an improvement is made, the benchmark performance targets will be tightened in future years, resulting in ongoing benefits to consumers; while the business only receives a one-off reward.

Customers will only pay for sustained reliability improvements. One-off improvement will only result in the business receiving a temporary one-off reward. But, the reward will be refunded to customers in future years when performance returns to normal.

Consequently, in conjunction with the CESS and EBSS, the STPIS ensures that:

- any additional investments to improve reliability are based on prudent economic decisions
- reductions in capex and opex are achieved efficiently, rather than at the expense of service levels to customers

AusNet Services' revised revenue proposal has not included capex or opex allowances for reliability improvement; therefore no adjustments to its reliability targets are required. Please refer to Attachment 5 – Capital expenditure and Attachment 6 – Operating expenditure of the final decision for further details.

The NER requires that we provide adequate funding for a distributor to maintain its current level of reliability. Any underspend in the past is likely the result of efficiency improvements.

Our VCR survey found that:

- Residential customers continue to value reliability and have a preference to avoid longer outages, and outages which occur at peak times (defined as 7am to 10am and 5pm to 8pm).[14]
- Industrial customers also indicated their value for supply reliability.[15]
- While there is no measure of the willingness to pay for widespread long duration outages that lasted three, six or twelve times longer than a one hour outage, for outages of longer duration, and/or covering wider areas, the VCR could begin to increase again beyond a certain threshold as different types of costs are incurred that would not arise in the surveyed 'standard' localised outages.[16]

The incentive rates under the scheme for the forthcoming regulatory control period are based on the latest VCR survey findings. Hence, we consider that the scheme incentive mechanism is reflective of customers' value in terms of reliability outcomes.

We would not expect that a distributor will allow its reliability level to deteriorate significantly due to the operational and business risks it would face in the long run. In the short term, STPIS off-sets a distributor’s attempts to cut cost and reduce service levels by imposing a penalty, operating as an early indicator of business practices.

In the coming months, we will be undertaking a broad review of our incentive schemes and how they are operating. We will look into various issues that have been raised by both consumers and businesses about aspects of individual schemes and their interrelationships. We encourage stakeholders to participate in this process.

10.5 Reasons for final decision

We will apply the STPIS to AusNet Services in accordance with the scheme. This includes using the latest 2019–20 reliability data to calculate AusNet Services' performance targets for the next regulatory control period.

The following section sets out our detailed considerations on applying the STPIS to AusNet Services for the 2021–26 regulatory control period.

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14 *AER - Values of Customer Reliability Review – Factsheet,* December 2019.

15 *AER - Values of Customer Reliability Review – Factsheet,* December 2019. The higher industrial VCR value has driven a small increase in the National Electricity Market (NEM) and state VCR values compared to 2014. This is because proportionally, industrial customers use more energy relative to other customer segments and so, have a greater influence on load weighted VCR numbers.

16 AER: *Final Conclusions, Widespread and Long Duration Outages - Values of Customer Reliability,* September 2020, p.17

10.5.1 Revenue at risk

We determine that the cap on revenue at risk under the STPIS be reduced to 4.5 per cent from 5 per cent, taking into consideration the application of the CSIS with a revenue at risk of 0.5 per cent. The CSIS is intended to replace the telephone service component of the STPIS, which has a revenue cap of 0.5 per cent. The total revenue placed at risk under both schemes will remain at 5 per cent as per the design of the STPIS. This is consistent with our other determinations for the Victorian distributors. Please see attachment 12 regarding the CSIS.[17]

10.5.2 Reliability of supply component

Applicable components and parameters

We will apply unplanned SAIDI, unplanned SAIFI and unplanned MAIFI parameters under the reliability of supply component to AusNet Services' feeders for the 2021–26 regulatory control period. Unplanned SAIDI measures the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIFI measures the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned MAIFI measures the total momentary interruptions divided by the total number of distribution customers.[18]

Exclusions

The STPIS allows certain events to be excluded from the calculation of the s-factor revenue adjustment. These exclusions include the events specified in the STPIS, such as the effects of transmission network outages and other upstream events. They also exclude for the effects of extreme weather events that have the potential to significantly affect AusNet Services' underlying STPIS performance.

AusNet Services' proposed to calculate the major event day threshold using the 2.8 beta method in accordance with our draft decision and the scheme.[19]

Performance targets

The STPIS specifies that the performance targets should be based on the average performance over the past five regulatory control years. It also states that the performance targets must be modified for:

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[17] AER. *Draft Decision AusNet Services Distribution Determination 2021 to 2026 Attachment 10 Service target performance incentive scheme*, September 2020; AER, *Final framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy, Regulatory control period commencing 1 January 2021*, January 2019, p. 76.

[18] Sustained interruption means supply interruption longer than three minutes. Momentary interruptions are those supply interruptions lasting less than three minutes.

[19] AusNet Electricity Services, *Electricity Distribution Price Review 2022–26 Revised Regulatory Proposal*, December 2020, p. 145.

- any reliability improvements completed or planned where the planned reliability improvements are included in the expenditure program proposed by the network service provider and expected to result in a material improvement in supply reliability;[20] and
- where the actual performance outcome exceeds the revenue at risk cap[21]

Our final decision has not included capex for programs to improve reliability, therefore no adjustment to AusNet Services' reliability targets is required.

Our calculated performance targets for AusNet Services for the 2021–26 regulatory control period are presented is in Table 10.2. These performance targets were calculated using historical data as defined under with STPIS 2.0 submitted by AusNet Services in its revenue proposal. Stakeholders should be aware that previously published historical performance data is not comparable with the data submitted by AusNet Services for target setting purposes for the next regulatory control period. This is due to changes in the definition of sustained interruptions from longer than one minute to three minutes as recommended by the Australian Energy Market Commission and feeder definitions.[22]

10.5.3 Customer service component

For the final decision, we will not apply the STPIS telephone answering target and incentive rate to AusNet Services in the next regulatory control period because the distributor has opted to apply the CSIS.

As discussed in the draft decision, we agreed with the submission from the CCP17 acknowledging telephone answering as an important service for many consumers.[23] For the final decision, we consider that AusNet Services should continue to report on the telephone answering parameter in the next regulatory control period.

10.5.4 Incentive rates

The incentive rates applicable to AusNet Services for the reliability of supply performance parameters of the STPIS have been calculated in accordance with clause 3.2.2, using the formulae provided as Appendix B of the STPIS 2.0 and our VCR review published in December 2019.

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20 AER, , *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0*, November 2018, cl. 3.2.1(a)(1A).

21 AER, , *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0*, November 2018, cl. 3.2.1(a)(1B).

22 AER, *Distribution Reliability Measures Guideline*, November 2018, pp. 7–8.

23 AER Consumer Challenge Panel, *CCP17 Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, June 2020, p. 36.

Our final decision on AusNet Services' incentive rates are at Table 10.1.[24]

10.5.5 Value of customer reliability to calculate the incentive rates

Consistent with our draft decision, we have calculated AusNet Services' incentive rates by using our VCR Review published in December 2019.[25]

The VCR for network segments outlined in Table 10.3 were applied to calculate AusNet Services' incentives rates for the 2021–26 regulatory control period.

Table 10.3 Value of customer reliability ($/MWh)

	Urban	Short rural	Long rural
VCR	41,210	41,210	41,210

Source: AER, *Value of customer reliability review, final report*, December 2019, p. 17 and p. 71; VCR values are escalated to the December 2020 quarter.

10.6 Transitional arrangements for the STPIS

This section addresses the transitional issues relating to the STPIS and how we intend to adjust the s-factor between regulatory control periods under STPIS 2.0.

The STPIS operates as part of the building block determination and is applied via the control mechanism. Through the s-factor component of the STPIS, distributors are penalised or rewarded for diminished or improved service performance compared to predetermined targets. Distributors are either rewarded or penalised via network charges two years after the end of each regulatory control year because audited performance data is only available after the regulatory year is completed—hence, the earliest time the s-factor can apply is the year following audited performance data availability.

Consequently, the s-factor outcomes for 2019 and 2020 will apply to prices in the 2021–22 and 2022–23 regulatory control years respectively.

A key amendment under STPIS 2.0 is to simplify the scheme by specifying STPIS outcomes as a fixed monetary amount, rather than as a percentage adjustment to the maximum allowable revenue as set out in Appendix C.[26] This appendix also sets out the s-factor calculation formula and the operation of the s-bank mechanism under this approach.

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[24] AER, *Final decision. Electricity distribution network service providers, Service target performance incentive scheme,* November 2009, cl. 5.3.2(a).

[25] AER, *Values of Customer Reliability Review - Final Report*, December 2019.

[26] AER, *Electricity distribution network service providers, Service target performance incentive scheme, Version 2.0, Appendix C - Adjustments to allowed revenue*, November 2018.

To transition to STPIS 2.0, AusNet Services' s-factor outcomes for 2019, 2020 and the determination extension period will be converted to a dollar value before being applied in the price control formula in the next regulatory control period. Please refer to Attachment 14 – Control mechanisms of the final decision for details.

We have consulted with Victorian distributors on our proposed transition to STPIS 2.0.[27] We consider that, as a principle, the transition should be revenue neutral under either STPIS 1.0 or STPIS 2.0. Nonetheless, an earlier transition to STPIS 2.0 will likely provide more clarity and certainty. Victorian distributors did not raise an objection to our proposed methodology.

11 Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CESS	capital expenditure sharing scheme
CSIS	Customer Service Incentive Scheme
DB	distribution network service provider
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
GSL	guaranteed service levels
MAIFI	Momentary Average Interruption Frequency Index
NEM	National Electricity Market
NER	National Electricity Rules
opex	operating expenditure
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
VCR	values of customer reliability

FINAL DECISION

AusNet Services
Distribution Determination
2021 to 2026

Attachment 12
Customer service incentive scheme

April 2021

Inquiries about this publication should be addressed to:

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AER reference: 63599

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

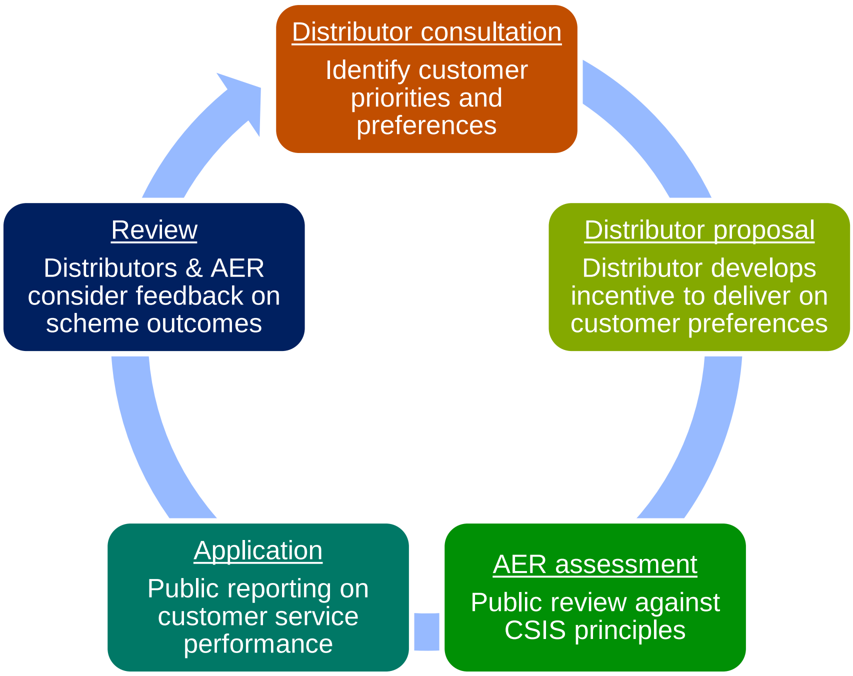
Contents

12 Customer Service Incentive Scheme

The Customer Service Incentive Scheme (CSIS) is designed to encourage electricity distributors to engage with their customers and provide customer service in accordance with their preferences. The CSIS allows us to set targets for distributor customer service performance and require distributors to report on performance against those targets. Under the CSIS, distributors may be financially rewarded or penalised depending on how they perform against customer service targets.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers. This flexibility will allow for the evolution of customer engagement and adapt to the introduction of new technologies. The principles of the scheme target it at customer preferences and provide safeguards to ensure rewards/penalties under the scheme are commensurate with improvements/detriments to customer service. Figure 1 illustrates how the CSIS works in practice.

Figure 1 Application of the CSIS



Source: AER, *Explanatory Statement Customer Service Incentive Scheme*, July 2020, p. 4.

Under the CSIS, distributors may propose different 'incentive designs'. For the CSIS to be applied, incentive designs must meet the scheme's principles. Importantly, we will not apply an incentive design unless a distributor can demonstrate that its customers support the incentive design through genuine engagement.

We consider that AusNet Services' customers will benefit from the application of the CSIS. Overall, the incentives target areas of service that customers want improved. We have set performance targets under the CSIS at the level of current performance. This will ensure that AusNet Services is only rewarded for genuine performance improvements. The incentive rates have been tested with customers to confirm that they align with the value that customers place on the performance improvement. This means that, even if AusNet Services is able to easily beat the targets, customers will still benefit. Further, if distributors seek to apply the CSIS in subsequent regulatory control periods, the targets under the scheme will be set in accordance with any improved level of customer service.

To ensure that the CSIS is working as intended, we will publicly share performance data on our website. We will also review the application of the CSIS within our performance reports (as illustrated in Figure 1). Feedback received on the application of the scheme to AusNet Services may be used to guide other distributors in designing their proposals.

During 2021–26 regulatory control period, we may also decide to suspend the application of the CSIS to AusNet Services, if we are satisfied that the incentive design is no longer compliant with the CSIS principles.[1]

12.1 Final decision

Our final decision is to uphold our draft decision and apply AusNet Services' proposed incentive design.[2] Final targets for AusNet Services have been updated following the receipt of performance data for 2019–20.

The total revenue at risk for customer service performance will be 0.5 per cent of total annual revenue.

12.2 AusNet Services' revised proposal

AusNet Services has trialled a new process to develop its regulatory proposal called 'New Reg' under which it negotiated elements of its regulatory proposal with an independent, expert Customer Forum.[3] As part of the negotiations, AusNet Services negotiated to apply customer service incentives with its Customer Forum.

The Customer Forum engaged extensively in consultation in the development of AusNet Services' proposed incentive design. A comprehensive list of the Customer Forum's engagement activities is provided in Appendix B of the Customer Forum's Final Engagement Report.[4]

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[1] AER, *Final Customer Service Incentive Scheme*, July 2020, Section 4.3.

[2] AusNet Services, *Electricity Distribution Price Review 2022–26*, January 2020, p. 233.

[3] The AER, Energy Networks Australia and Energy Consumers Australia have developed "New Reg", a joint initiative to explore ways to improve sector engagement and identify opportunities for regulatory innovation. The goal of this initiative is to ensure that customers' preferences drive energy network businesses proposals and regulatory outcomes. Under the New Reg process the most significant departure from traditional practice is that a Customer Forum negotiates aspects of the regulatory proposal in advance of lodgement with the AER. The Customer Forum does not represent the perspectives of particular interests, instead conducting research and customer engagement to ensure it can effectively represent the perspectives of all the network businesses' customers.

[4] AusNet Services' Customer Forum, *Customer forum final engagement report*, January 2020, pp. 63–79.

In its CSIS incentive design, AusNet Services proposed four 'performance parameters' to be incentivised. These are customer satisfaction with:

1. Communication on unplanned outages;

2. Communication on planned outages;

3. Customer service for new connections (basic and standard); and

4. Customer service in managing complaints.

For each parameter, customer satisfaction is measured using a survey where customers rate AusNet Services' customer service with a score between 0 and 10, where 0 is 'extremely dissatisfied' and 10 is 'extremely satisfied. Below we outline each of these parameters in further detail.

12.2.1 Communication relating to Unplanned Outages

The unplanned outage parameter provides an incentive for AusNet Services to improve its communication on unplanned outages. [5] After an unplanned outage, AusNet Services will ask its customers to rate its communications in respect to that unplanned outage. As unplanned outages impact a broader group of customers, improvements in this area are considered to have widespread impact.[6]

Based on AusNet Services’ independent research gathering of monthly telephone surveys to residential and business customers, with a total sample size of 815 participants over the 2019–20 period for electricity and gas services, the average target for unplanned outages is 6.5.[7]

AusNet Services and its Customer Forum agreed on a reward/penalty of $484 246 (0.08 per cent of revenue) for each 1-point improvement/degradation in satisfaction annually.[8] The updated targets were communicated with the Customer Forum in October 2020.[9]

5 Unplanned outages are defined by AusNet Services as an unexpected interruption to supply that has a duration of at least one minute. See AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 235.

6 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 235.

7 AusNet Services, *Revised Regulatory Proposal ASD - CSIS - CSAT data, targets and reporting template*, December 2020.

8 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 238.

9 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 142.

12.2.2 Communication relating to Planned Outages

Planned outages similarly affect all customers in specified regions, and have a widespread impact.[10][11] Like unplanned outages, AusNet Services will ask its customers to rate its communication on planned outages.

Based on a total sample size of 1045 participants over the 2019–20 period, the average target for planned outages is 7.4 for electricity and gas services.

AusNet Services and its Customer Forum agreed on a reward/penalty of $484 246 (0.08 per cent of revenue) for each 1-point improvement/degradation in satisfaction annually.[12]

12.2.3 New connections (basic and standard)

New connections affect a smaller group of customers, but is considered to be an important interaction stage with the customer, as delays may occur when seeking to occupy a premises.[13] This parameter captures both basic and standard connections.[14]

Based on a sample size of 735 participants over the 2019–20 period, the current target for new connections is 6.6.

AusNet Services and its Customer Forum agreed on a reward/penalty of $484 246 (0.08 per cent of revenue) for each 1-point improvement/degradation in satisfaction annually.[15]

12.2.4 Complaints

Complaints are brought by a small portion of AusNet Services' overall customer base, and may be indicative of a deficiency in service delivery.[16] AusNet Services defines this parameter to capture escalated customer disputes that have not been resolved by a Resolutions Team member.[17]

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10 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 234.

11 Ibid. AusNet Services defines planned outages as pre-arranged interruptions to supply where affected customers are given advanced notification (including both short sustained and general interruptions), p. 235.

12 AusNet Services, *Revised Regulatory Proposal ASD - CSIS - CSAT data, targets and reporting template*, December 2020

13 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 234.

14 AusNet Services defines a basic connection as including a meter hanger, without the need for network changes or upgrades. A standard connection however, requires a network change, and may include a new pole installation, line extension or upgrade, construction or technical changes. It, however excludes negotiated or more complex connections. Source: AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 235.

15 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 238.

16 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 234.

17 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 235.

Based on a total sample size of 295 participants over the 2019–20 period, the average target for planned outages is 3.8.[18]

AusNet Services and its Customer Forum agreed on a reward/penalty of $242 123 (0.04 per cent of revenue) for each 1-point improvement/degradation in satisfaction annually.[19]

However, unlike the above parameters, a deadband ('minimum threshold') is applied for customer complaints. As the current performance is stipulated as 3.8 out of 10, with industry leading performance 5.8 out of 10, the Customer Forum expressed concern that AusNet Services would be rewarded for improving complaints from a low baseline.[20] AusNet Services agreed to a proposed deadband of 5 out of 10, and will therefore only receive incentive payments if performance exceeds this threshold.[21]

12.3 Assessment approach

Under Section 2.1 of the final CSIS, we will apply a distributors' proposed incentive design to a distribution determination if we consider it:

(a) will achieve the CSIS objectives;

(b) meets the incentive design criteria, which includes CSIS principles; and

(c) is accompanied by a proposal that meets the incentive design proposal requirements.

We have therefore assessed AusNet Services' proposed incentive design against this criteria.[22] The objectives for the CSIS are that it:

1) Is consistent with the *national electricity objective* in section 7 of the *National Electricity Law (NEL),*

2) Is consistent with clause 6.6.4 of the *National Electricity Rules (NER),* which requires that, in developing a *small-scale incentive scheme* the *AER* must have regard to the following matters;

   (a) *Distributors* should be rewarded or penalised for efficiency gains or losses in respect of its *distribution systems*,

   (b) 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;

   (c) 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

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18 AusNet Services, *Data Targets and Reporting Template*, December 2020.

19 AusNet Services, *Data Targets and Reporting Template*, December 2020.

20 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 237.

21 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 237.

22 AER, *CSIS Explanatory Statement*, July 2020, section 2.1.

result from efficiency losses in respect of a distribution system should warrant the penalties provided under the *scheme*

(d) The interaction of the *scheme* with other incentives that distributors may have under the rules, and

(e) The *capital expenditure objectives* and the *operating expenditure objectives*.

3) Achieves clauses 1.4(1) and 1.4(2) by aligning the incentives of distributors with the customer service preferences of their customers.

4) Promotes transparency and understanding throughout the *National Electricity Market* (NEM) regarding a *distributor's* customer service initiatives.

We consider that these objectives are complimentary, and overall the scheme will deliver on these and the national electricity objective. An incentive for AusNet Services to maintain and improve its customer services, in line with the interests of its customers, gives effect to the long term interests of consumers.[23] Our assessment is set out below.

12.4 Reasons for final decision

The reasons for our final decision are consistent with those in our draft decision.[24] We consider that AusNet Services' design achieves the CSIS objectives and meets the incentive design requirements, having regard to the principles of the CSIS.

We consider that AusNet Services has therefore satisfied the requirements under Section 2.1 of the CSIS. We set out our reasoning below.

12.4.1 CSIS objectives

AusNet Services' proposed incentive design will penalise AusNet Services for degrading, or reward AusNet Services for improving its customer service. To ensure that only efficient customer service performance improvements are delivered, penalties and rewards under the scheme align with the value that customers place on the customer service. As this value has been identified through customer engagement, the scheme aligns AusNet Services' interests with those of its customers. We are therefore satisfied that the benefits (detriments) to consumers that are likely to result from efficiency gains (losses) warrant the rewards (penalties) provided under the scheme.

We do not consider that the CSIS duplicates any other incentive schemes AusNet Services is currently subject to. AusNet Services intends that the CSIS replaces the current service target performance incentive scheme (STPIS) call answering parameter, as it achieves broader consumer objectives, while matching the overall revenue at risk.[25]

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23 NEL, Section 7.

24 AER, *AusNet Services Distribution Determination 2021–26 – Draft Decision*, September 2020.

25 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, pp. 233, 237.

We have had regard to the capital[26] and operating[27] expenditure objectives in applying the CSIS. In particular we note the objective to 'maintain the quality, reliability and security of supply of standard control services'. By setting targets at or above historical performance we are providing AusNet Services with an incentive to at least maintain its current levels of customer service.

AusNet Services' public negotiation with its Customer Forum has promoted an understanding of customer service. AusNet Services' ongoing application and reporting on the CSIS will further this understanding.

As AusNet Services is incentivised to maintain at least current levels of performance through rewards and penalties, the proposed scheme meets the objectives of a small scale incentive scheme. These incentives are aligned with customer preferences, as parameters and targets were identified through consumer engagement processes, and approved by the Customer Forum.

By requiring AusNet Services to report on its performance, the scheme contributes to promote consumer understanding in accordance with the CSIS objectives.

12.4.1.1 Incentive design criteria

Under Section 3.1 of the CSIS, the incentive design criteria include a number of principles. We have considered AusNet Services' proposal against these principles.

The CSIS's principles are split into four different categories that relate to each of the necessary elements of an incentive design, being;

- performance parameters – what customers want to be incentivised under the scheme
- measurement methodology – how performance is measured
- assessment approach – how performance is rated
- financial component – how penalties/rewards are calculated and applied.

We separately consider each of these components of AusNet Services' proposed incentive design below.

12.4.1.2 Performance parameters

The relevant principles for performance parameters are that each performance parameter must be an aspect of the customer experience component of the distributor's standard control services;

[26] NER, cl.6.5.7.

[27] NER, cl.6.5.6.

(a) that the customers of the distributors particularly value and want improved, as evidenced by genuine engagement with, and support from, the distributor's customers,

(b) that is substantially within the control of the distributor, and

(c) for which the distributor does not already have an incentive under another incentive scheme or jurisdictional arrangement. [28]

Genuine engagement with, and support from a distributor's customers is necessary for us to apply an incentive design under the CSIS. We expect that customer support would be demonstrated by distributors through broad consultation, using a number of different consultation processes to reflect views across vulnerable household customers, small business and commercial and industrial businesses.[29] Customers should also be provided with more than one opportunity to provide input.[30]

AusNet Services' proposed incentive design has been underpinned by genuine engagement with its customers through its customer research and negotiations with its Customer Forum.[31] This engagement has been documented in the Customer Forum's engagement report and on AusNet Services' website.[32] The parameters were agreed upon after extensive negotiations with the Customer Forum,[33] and reflected 'key areas of concern amongst customers'.[34] Submissions from the Victorian Community Organisations and Energy Consumers Australia considered that AusNet Services' metrics are reasonable and a likely reflection of customer priorities,[35] and focused on areas that customers value.[36] The Consumer Challenge Panel, sub-panel 17 (CCP17) also submitted that it was supportive of the CSIS, but noted that the CSIS may not be readily accessible to representative groups. To address this the CCP17 encouraged us to give consideration as to how this challenge might be addressed through 2021, potentially by consulting with customer representatives and other stakeholders to understand how best to analyse and present the information in a meaningful way.[37] Through our network performance reporting, and the upcoming review of incentive schemes, we will work with stakeholders to present timely, clear and informative reporting on incentive scheme payments and outcomes. We will also regularly revisit how we present data in the ongoing development of our performance reports.

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28 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

29 AER, *CSIS Explanatory Statement,* July 2020, p. 9.

30 AER, *CSIS Explanatory Statement*, July 2020. p. 9.

31 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

32 AusNet Services' Customer Forum, *Customer forum final engagement report*, January 2020, pp. 63–79.

33 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 232.

34 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 234.

35 Victorian Community Organisations, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 26.

36 Energy Consumers Australia, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 18.

37 CCP17, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, p. 68.

Regarding the second principle, we consider that the performance parameters are substantially within the control of AusNet Services,[38] as they relate directly to the services it provides. There are no duplicate incentive schemes or jurisdictional arrangements covering these parameters.[39] We note that the CSIS replaces the existing STPIS telephone answering parameter.

AusNet Services' incentive design meets the performance parameter principles as the parameters were developed through genuine consumer engagement, do not duplicate other incentives and are in its control.

12.4.1.3 Measurement methodology

The measurement methodology principles govern how performance under the scheme is measured. The relevant principles for measurement methodology are that for each performance parameter, the proposed measurement:

(a) accurately measures the features of the performance parameter,

(b) is sufficiently independent, in that it is either conducted by an independent third party or based upon an independently developed methodology,

(c) is compiled in an objective and reliable manner with data retained in a secure and logically indexed database, and

(d) produces results that could be audited by an independent third party.

AusNet Services' proposed approach accurately measures the features of the identified performance parameters,[40] and is based upon an independently developed methodology.[41]

AusNet Services has engaged Customer Service Benchmarking Australia (CSBA) to survey its performance for the CSIS. This is the same firm which gathered historical performance data used to set targets for the CSIS.[42]

AusNet Services has applied ISO 20252 (Market & Social Research) standards in collecting its survey data. The data is thus compiled in an objective and reliable manner.[43] CSBA retains the data in a secure and logically indexed database,[44] which is capable of being audited.[45]

CSBA conducts its research through quantitative measurements, with optimum sample sizes to ensure results are statistically robust and within acceptable margins of error.

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38 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

39 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

40 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

41 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

42 AusNet Services, *Electricity Distribution Price Review 2022–26 – part II*, January 2020, p. 235.

43 CSBA, *Quality Management System - Quality Management Population Statement*, p. 4.

44 AER, *CSIS Explanatory Statement*, July 2020, p. 8.

45 AER *CSIS Explanatory Statement*, July 2020, p. 8.

Where relevant, weightings are used to enhance the representations of samples to reflect the target population. Consistent rating scales are adopted and indexed against industry norm.[46]

As the proposed methodology is quantified and external audits can be implemented to verify outcomes, we consider that the principles have been met.

12.4.1.4 Assessment approaches

The assessment approach principles cover how performance is evaluated and then translated into an expression of improvement or deterioration which can be used to determine a reward or penalty. These principles establish a baseline or neutral level of performance against which performance is assessed.

For each of its parameters AusNet Services has proposed average historical performance as the target. This will ensure that AusNet Services is only rewarded if it improves on its historical performance.[47] However, for the complaints parameter, the Customer Forum considered that the target of 3.6 out of 10, as based on average historical performance, was not considered acceptable. Under the revised targets based on 2019–20 historical performance, the target is 3.8 out of 10, and remains low. Using historical targets would incentivise performance off a low baseline, noting that industry leading performance is 5.8 out of 10.[48] A deadband has therefore been applied for the complaints threshold to be set at 5 out of 10, ensuring that AusNet Services is only rewarded for material improvements to customer service.[49]

AusNet Services' historical performance in respect of the identified parameters has been quantified as a single value between 1 to 10,[50] ensuring that actual performance can be compared to the performance targets to calculate the applicable penalty/reward.

There is a clear relationship between the performance and determination of a reward or penalty,[51] with improvements/deterioration resulting in commensurate rewards or penalties.[52] Incentive rates are provided in Table 9-1 of *AusNet Services' Revised Regulatory Proposal 2022–26.*

AusNet Services' incentive design meets the principles as it establishes a direct relationship between identified parameters and AusNet Services' performance ensuring that it is correctly rewarded or penalised.

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46 CSBA, *Quality Management System - Quality Management Population Statement*, p. 1-2.

47 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5.

48 AusNet Services, *Electricity Distribution Price Review 2022–26*, January 2020, pp. 236-7.

49 See Section 12.2.4 of this paper.

50 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5.

51 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5.

52 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5.

12.4.1.5 Financial

AusNet Services is rewarded or penalised financially in proportions relative to the degree of performance, as calculated by the identified value of the service improvement.[53] The fixed performance targets are set using the average of the Customer Satisfaction data,[54] with rewards or penalties set for any 1 point change in performance.[55] While there is a subjective element in the agreement of these rates, it was agreed with the Customer Forum, through transparent and genuine consultation[56] that the level would not unduly reward AusNet Services.[57]

The Victorian Community Organisation's submission noted that whilst it was supportive of the proposed CSIS, there was a concern that target measures may be 'too easily achievable'.[58] Whether the targets are ‘easy to achieve’ remains to be seen. However, we note that AusNet Services will only be rewarded if it improves on historical performance and only to the extent that customers consider is appropriate for the service improvement. Thus we consider that customers will benefit regardless of how easily AusNet Services is able to improve its performance. We also note that the total rewards are capped at 0.5 per cent of total revenue protecting customers from significant price increases.

AusNet Services considered that the proposed incentive rates would require a significant increase for the maximum reward to be achieved.[59] Irrespective of the difficulty of the targets, we note that customers will benefit from the application of the CSIS.

To ensure that the incentives do not exceed the value that customers attribute to the level of service improvement observed,[60] AusNet Services has applied a deadband to the complaints parameter. By applying a deadband at 5 out of 10, as opposed to being rewarded for any performance above 3.8 out of 10, it ensures that AusNet Services is only rewarded for material improvements to customer service.[61]

In its revised proposal, AusNet Services proposed higher targets for communication on planned outages, customer service for new connections and customer service in managing complaints. These targets have been set to reflect improved customer service and satisfaction levels in 2019–20,[62] and aligns with our direction that targets use the most recent performance data.

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53 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 238.

54 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 236.

55 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 236.

56 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 6.

57 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 237.

58 Victorian Community Organisations, S*ubmission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, p. 61.

59 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 237.

60 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5

61 AusNet Services, *Electricity Distribution Price Review 2022–26 – part III*, January 2020, p. 236.

62 AusNet Services, *Revised Regulatory Proposal 2021–26*, p. 143.

We informed AusNet Services that a minor amendment is required to the control formula to apply a two year lag rather than a three year lag between performance measurement and revenue adjustment.[63] AusNet Services has agreed with this approach.[64] This revised approach is consistent with how the CSIS is intended to operate and, therefore we consider it will better achieve the scheme objectives. The revenue control formula under the CSIS is not prescriptive and we consider that AusNet Service's proposed alternative application gives effect to the scheme’s objective.

The revised revenue adjustment formula further ensures that rewards or penalties are commensurate with service improvements or degradations.[65]

When considered in aggregate, the incentives available to AusNet Services do not exceed the value customers attribute to the customer service.[66] The quantum of the incentives or penalties are therefore commensurate with any service improvement or deterioration, and hence satisfy the financial principles.

63 Specifically we have altered the formula on page 10 of the CSIS to the following: $H_t' = \sum_p ir^p \times [Act_t^p - Tar_t^p]$.

64 AusNet Services, Information request 92 – Q1 - CSIS Revenue Adjustment Formula, 3 March 2021.

65 AER, *Final Customer Service Incentive Scheme*, July 2020, Section 3.2(5) (b).

66 AER, *Final Customer Service Incentive Scheme*, July 2020, p. 5.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
CCP17	Consumer Challenge Panel, sub-panel 17
CSBA	Customer Service Benchmarking Australia
CSIS	Customer service incentive scheme
Distributor	Distribution network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
STPIS	service target performance incentive scheme

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 13 Classification of services

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

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Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

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A AER final decision on service classification of AusNet Services' distribution services 2021−26

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
Common distribution service - use of the distribution network for the conveyance/flow of electricity (including the services relating to network integrity)			
Common distribution service (formerly 'network services')	The suite of activities that includes, but is not limited to, the following: • the planning, design, repair, maintenance, construction, and operation of the distribution network • works to fix damage to the network (including recoverable works caused by a customer or third party) • support for another network during an emergency event • procurement and provision of network demand management activities for	Standard control	Standard control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	distribution or system reliability, efficiency or security purposes • activities related to 'shared asset facilitation' of distributor assets[1] • emergency disconnect for safety reasons and work conducted to restore a failed component of the distribution system to an operational state upon investigating a customer outage • establishment and maintenance of National Metering Identifiers (NMIs) in market and/or network billing systems, and other market and regulatory obligations • ongoing inspection of private electrical networks (not part of the shared network) required under legislation for safety reasons[2] • supply abolishment of basic connection[3] • customer safety information, e.g. 'dial before you dig' services • Bulk supply point metering - activities relating to monitoring the flow of electricity through the distribution network		

[1] Revenue for these services is charged to the relevant third party and is treated in accordance with the shared asset guideline. 'Shared asset facilitation' refers to administrative costs. It does not refer to the costs associated with providing the unregulated service itself.

[2] The Victorian Electricity Safety Act 1998, clause 113F, requires Vic DNSPs to inspect overhead private electric lines.

[3] This service is classified as Standard Control Services under the 2016–20 Determination for public safety reasons. Victorian DNSPs wish to continue with the classification.

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	• Third party initiated network asset relocations/re-arrangements under ESCV Guideline 14.[4] • Transmission network support		
Network ancillary services − customer and third party initiated services related to common distribution services			
Access permits, oversight and facilitation	Activities include: • a distributor issuing access permits or clearances to work to a person authorised to work on or near distribution systems including high and low voltage • a distributor issuing confined space entry permits and associated safe entry equipment to a person authorised to enter a confined space • a distributor providing access to switch rooms, substations and other network equipment to a non-Local Network Service Provider party who is accompanied and supervised by a distributor's staff member. May also include a distributor providing safe entry equipment (fall-arrest) to enter	Not classified	Alternative control

[4] This classification applies where a customer contribution is calculated and applied in accordance with Essential Services Commission (ESCV) Guideline 14 or where a customer contribution is calculated and applied in accordance with any other relevant Victorian legislation or regulation, including regulations made under the National Electricity (Victoria) Act, 2005. The party requesting such works under this classification must pay the net cost of the works, subject to any rebates specified in Guideline 14 or by any other relevant Victorian legislation or regulation.

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	difficult access areas • specialist services (which may involve design related activities and oversight/inspections of works) where the design or construction is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets • facilitation of generator connection and operation of the network • facilitation of activities within clearances of distributor's assets, including physical and electrical isolation of assets		
Sale of approved materials or equipment	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network	Not classified	Alternative control
Notices of arrangement and completion notices	Examples include: • Work of an administrative nature where a local council requires evidence in writing from the distributor that all necessary arrangements have been made to supply electricity to a development. This includes: receiving and checking subdivision plans, copying subdivision plans, checking and recording easement details, assessing supply availability, liaising with developers if errors or changes are required, and preparing notifications of arrangement • Provision of a completion notice (other than a notice of arrangement). This applies where the real estate developer requests the distributor to	Not classified	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	provide documentation confirming progress of work. Usually associated with discharging contractual arrangements (e.g. progress payments) to meet contractual undertakings		
Network related property services	Activities include: • Network related property services such as property tenure services relating to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation • Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer	Not classified	Alternative control
Network safety services	Examples include: • provision of traffic control and safety observer services by the distributor where required • fitting of tiger tails, possum guards, and aerial markers • high load escorts • site visit relating to location of underground cables/assets • Third party request for de-energising wires for safe approach	Alternative control	Alternative control
Planned Interruption – customer requested	Examples include: • where the customer requests to move a distributor planned interruption	Not classified	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
amendment	and agrees to fund the additional cost of performing this distribution service outside of normal business hours		
Customer requested supply outage	Examples include: • customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach, which impacts other networks users)	Not classified	Alternative control
Inspection and auditing services	Activities include: • inspection and reinspection by a distributor, of gifted assets or assets that have been installed or relocated by a third party • investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of a third party service provider due to unsafe practices or substandard workmanship • auditing of a third party service provider's work practices in the field • re-test at a customer's installation, where the installation fails the initial test and cannot be connected	Alternative control	Alternative control
Provision of training to third parties for network related access	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network	Not classified	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	and to carry out switching on the distributor’s network. Examples of training might include high voltage training, protection training or working near power lines training		
Authorisation and approval of third party service providers design, work and materials	Activities include: • authorisation or re-authorisation of individual employees and subcontractors of third party service providers and additional authorisations at the request of the third party service providers (excludes training services) • acceptance of third party designs and works • assessing an application from a third party to consider approval of alternative material and equipment items that are not specified in the distributor’s approved materials list	Alternative control	Alternative control
Security lights	Provision, installation, operation, and maintenance of equipment mounted on distribution equipment used for security services, e.g. nightwatchman lights. Note: excludes connection services	Not classified	Alternative control
Customer requested provision of electricity network data	Data requests by customers or third parties including requests for the provision of electricity network data or consumption data outside of legislative obligations	Not classified	Alternative control
Third party funded network alterations or other	Alterations or other improvements to the shared distribution network to enable third party infrastructure (e.g. NBN Co telecommunications assets) to	Alternative control	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
improvements	be installed on the shared distribution network. This does not relate to upstream distribution network augmentation		
Customer initiated network asset relocations/re-arrangements	Relocation of assets that form part of the distribution network in circumstances where the relocation was initiated by a third party (including a customer), not provided under ESCV Guideline 14	Alternative control	Alternative control
Community network upgrades	Collective customer requested network enhancement. Activities related to community requests to augment the network to enable higher PV exports	Not Classified	Alternative Control
Metering services - activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters)			
Type 1 to 4 metering services	Type 1 to 4 metering installations[5] and supporting services are competitively available	Unregulated	Unregulated
Type 5 and 6 (inc. smart metering) services where the distributor remains responsible	Includes: • Recovery of the cost of type 5 and 6 metering equipment[6] including communications network (including meters with internally integrated load control devices)	Alternative control	Alternative control

[5] Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

[6] Includes the instrument transformer, as per the definition of a 'metering installation' in Chapter 10 of the NER.

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	• Testing, inspecting, investigating, maintaining or altering existing type 5 or 6 metering installations or instrument transformers • Quarterly or other regular reading of a metering installation • Metering data services that involve the collection, processing, storage and delivery of metering data, the provision of metering data from the previous two years, remote or self-reading at difficult to access sites, and the management of relevant NMI Standing Data in accordance with the NER		
Auxiliary metering services (type 5 to 7 including smart metering) where the distributor remains responsible	Activities include: • requests to test, inspect and investigate, or alter an existing type 5 or 6 metering installation • testing and maintenance of instrument transformers for type 5 and 6 metering purposes • Non-standard metering services for Type 5 to 7 meters and any other meter types introduced • works to re-seal a type 5 or 6 meter due to customer or third party action (e.g. by having electrical work done on site) • change distributor load control relay channel on request that is not a part of the initial load control installation, nor part of standard asset maintenance or replacement	Alternative control	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	• Remote de-energisation and re-energisation • Remote meter configuration • Field based special meter read • Office based special meter read • Metering exit services		
Type 7 metering services	Administration and management of type 7 metering installations in accordance with the NER and jurisdictional requirements. Includes the processing and delivery of calculated metering data for unmetered loads, and the population and maintenance of load tables, inventory tables and on/off tables	Alternative control	Alternative control
Connection services[7] - services relating to the electrical or physical connection of a customer to the network			
Basic connection services	Means a *connection service*[8] related to a *connection* (or a proposed *connection*) between a *distribution system* and a *retail customer's* premises (excluding a non-registered *embedded generator's* premises) in the following	Alternative control	Alternative control

[7] When discussing connections, we must consider how connection policies and chapter 5A of the NER impact the regulation of connection services. For this reason, we will not be able to completely address the classification of connection services in the classification guideline.

[8] Italics denotes definitions in Chapter 5A of the NER.

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	circumstances: (a) either: 1. the *retail customer* is typical of a significant class of *retail customers* who have sought, or are likely to seek, the service; or 2. the *retail customer* is, or proposes to become, a *micro embedded generator*; and (b) the provision of the service involves minimal or no *augmentation* of the *distribution network*; and (c) a *model standing offer* has been approved by the AER for providing that service as a *basic connection service*.		
Standard connection service	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a model standing offer has been approved by the AER.	Standard control	Standard control
Negotiated connection	Means a connection service (other than a basic connection service) for which a DNSP provides a connection offer for a negotiated connection contract. This includes connections under Chapter 5 of the NER.	Standard control	Standard control
Connection application and management services	• Connection application related services • Works initiated by a customer or retailer that are specific to the	Alternative control	Alternative control

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	connection point. This includes, but is not limited to: • field based de-energisation[9] and re-energisation • Non basic supply abolishment or reposition non-basic connection • Temporary connections (e.g. for builder's supply, fetes etc.) • overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. because of a point of attachment relocation). No material change to load • protection and power quality assessment • supply enhancement (e.g. upgrade from single phase to three phase) • customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g. change protection settings) • upgrade from overhead to underground service • rectification of illegal connections or damage to overhead or underground service cables • calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user		

9 De-energisation services related to business as usual activities and de-energisation services that may relate to changing over meter types

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
	with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER • calculation of site specific loss factors when required under the NER • power factor correction • embedded network management • assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers • processing preliminary enquiries requiring site specific or written responses • undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants • liaising with groups representing multiple connecting parties (e.g. community group upgrades) • site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects • registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER		

Service group	Further description	Current classification 2016–20	AER final decision classification 2021−26
Enhanced connection services	Other or enhanced connection services provided at the request of a customer or third party that include those that are: • provided with higher quality of reliability standards, or lower quality of reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance • in excess of levels of service or plant ratings required to be provided by the distributor	Alternative control/ negotiated/ Not classified	Alternative control
Public lighting - lighting services provided in connection with a distribution network			
Public lighting	(1) Operation, maintenance, repair and replacement public lighting services (2) Alteration and relocation of public lighting assets (3) New public lighting services incl. greenfield sites & new light types (distributor provided) (4) Provision, construction and maintenance of emerging public lighting technology	Alternative control/ negotiated	Alternative control

FINAL DECISION

AusNet Services, CitiPower, Jemena, Powercor, and United Energy
Distribution Determination
2021 to 2026

Attachment 14
Control mechanisms

April 2021

Inquiries about this publication should be addressed to:

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Note

This attachment forms part of the Australian Energy Regulator's (AER) final decision on the distribution determination that will apply to AusNet Services, CitiPower, Jemena, Powercor and United Energy for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

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Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer Service Incentive Scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

14 Control mechanisms

Control mechanisms impose limits over the prices an electricity distribution network service provider can charge and/or the revenues it can recover from customers for the provision of its direct control services (standard and alternative control services).

The forms of the control mechanisms that will apply to a distribution determination and the formulae that give effect to those control mechanisms are considered during the framework and approach (F&A) stage.[1] We have limited discretion to depart from the control mechanisms set out in the F&A paper.[2] For example, we can only depart from the formulae if we consider there has been a material change in circumstance.

This attachment sets out our final decision for the determination of:

- the form and formulae of the control mechanism for standard control services[3]
- the forms and formulae of the control mechanisms for alternative control services[4]
- how compliance with the control mechanisms is to be demonstrated[5]
    - including the mechanisms for recovering distribution use of system (DUoS) and type 5 and 6 metering (including smart metering) revenues, including adjustments for any revenue under or over recovery, and
- how to report the recovery of designated pricing proposal charges and jurisdictional scheme amounts, and the adjustments to be made to subsequent pricing proposals to account for any over or under recovery of these charges or amounts.[6]

14.1 Final decision

Our final decision for the determination of the control mechanisms that will apply to the Victorian distributors for the 2021–26 regulatory control period is the same as our draft decision, except we have:

- updated definitions of the formulae to facilitate the transition of the regulatory year timing from calendar years to financial years
- updated the I-factor definition in the standard control service revenue cap formulae to include annual adjustments for the customer service incentive scheme (CSIS)

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1 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 54–73.

2 NER, cl. 6.12.3(c) and (c1).

3 NER, cl. 6.12.1(11).

4 NER, cl. 6.12.1(12).

5 NER, cl. 6.12.1(13).

6 NER, cl. 6.12.1(19) and 6.12.1(20).

- allowed CitiPower to smooth its recovery of under-recovered distribution revenues in 2020 due to significantly reduced electricity consumption caused by the COVID-19 pandemic, and
- provided additional guidance on the annual pricing process relating to the transition to financial years as regulatory years and the resulting six-month extension period.

Control mechanism for standard control services

The form of control mechanism for standard control services is a revenue cap (section 14.4.5). The revenue cap formula is set out in Figure 14.1. The side constraints applying to annual price movements for each tariff class must be consistent with the formula in Figure 14.2.

The annual pricing proposals must demonstrate compliance with the standard control services revenue cap by:

- including adjustments for DUoS revenue under or over recovery in accordance with Appendix A of this attachment[7]
- recording the amount of revenue recovered from designated pricing proposal charges and associated payments in accordance with Appendix C,[8] and
- recording any jurisdictional scheme amounts it recovers and associated payments in accordance with Appendix D.[9]

Type 5 and 6 metering (including smart metering) services

The form of control mechanism for type 5 and 6 metering (including smart metering) services is a revenue cap (section 14.5.1). The revenue cap formula is set out in Figure 14.3. The side constraints applying to annual price movements for each of the Victorian distributors' tariff classes must be consistent with the formula in Figure 14.4.

The annual pricing proposals must demonstrate compliance with the type 5 and 6 metering (including smart metering) services revenue cap by including adjustments for under or over recovery in accordance with Appendix B of this attachment.[10]

Other alternative control services

The form of control mechanism for other alternative control services, including metering exit fees, public lighting and ancillary network services (fee based and quoted services), is a price cap (Section 14.5.2). The price cap formulae for fee-based alternative control services − where the price can be determined in advance − are set out in Figure 14.5. The price cap formula applying to the Victorian distributors' alternative control services provided on a quoted basis is set out in Figure 14.6.

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7 NER, cl. 6.18.2(b)(7).

8 NER, cl. 6.18.2(b)(6).

9 NER, cl. 6.18.2(b)(6A).

10 NER, cl. 6.18.2(b)(7).

For all services, Appendix F of this attachment sets out the requirements for the treatment of rounding values in annual pricing proposals. [11]

14.2 The Victorian distributors' revised proposals

The Victorian distributors accepted most aspects of our draft decision.[12] In their revised proposals, the Victorian distributors' also proposed the following for inclusion in our final decision:

- In regard to standard control services:
    - CitiPower, Powercor, and United Energy proposed an option be introduced to allow deferral of under-recovered revenues arising in year 2020 due to the COVID-19 pandemic.[13]
    - CitiPower, Powercor, and United Energy proposed that the I-factor definition be amended to specifically include the CSIS.[14]
    - AusNet Services proposed that recovery of deliberate under-recoveries should be allowed as they can arise from providing relief to customers.[15]
    - AusNet Services, CitiPower, Powercor, and United Energy proposed the levies they pay to Energy Safe Victoria (ESV) be recovered through the B-factor in the revenue cap formulae.[16]
    - The Victorian distributors proposed that new Australian Energy Market Operator (AEMO) market participant fees that are expected to be introduced during the regulatory control period be recovered through the B-factor in the revenue cap formulae.[17]
- In regard to alternative control services:
    - Jemena proposed the price cap formulae for services provided on a quoted basis include a margin.[18]

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[11] NER, cl. 6.18.2(b)(7).

[12] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 172; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Jemena, *Attachment 07-01 - Price control mechanisms*, December 2020, pp. v-vi; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

[13] CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Powercor, *Revised regulatory proposal 2021–26,* December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

[14] CitiPower, *Revised regulatory proposal 2021–26* December 2020, p. 62; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

[15] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 173-174.

[16] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 173; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

[17] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 173; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Jemena, *Attachment 07-01 - Price control mechanisms*, December 2020, p.2 Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26,* December 2020, p. 58.

[18] Jemena, *Attachment 07-01 - Price control mechanisms*, December 2020, pp. 9-10.

- AusNet Services proposed the price cap formulae for services provided on a quoted basis include a tax component to be consistent with tax approaches for standard control services.[19]

14.3 Assessment approach

Our assessment approach is unchanged from that set out in our draft decision.[20]

14.4 Reasons for final decision on standard control services

The following sets out the reasons for our final decision on the control mechanism formulae for standard control services. This reasoning and responses to the Victorian distributors' revised proposals are provided in the relevant control mechanism formula parameters.

14.4.1 Application of control mechanism formulae

14.4.1.1 Timing change from calendar to financial regulatory years

In 2021, AusNet Services, CitiPower, Jemena, Powercor, and United Energy (the Victorian distributors) will transition the timing of their regulatory years from calendar years to financial years (see our Decision on the six-month extension).[21] This change will create uniformity in the timing of regulatory years across the electricity distribution network service providers in the National Electricity Market (NEM). [22]

Where required, our final decision has updated the definitions of the control mechanism formulae to facilitate the transition.

14.4.1.2 Total allowable revenue

The Victorian distributors' annual total allowable revenue (TAR) for standard control services is determined by the revenue cap formula in Figure 14.1.

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[19] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 190-191.

[20] AER, *AusNet Services distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 8-10.

[21] AER, *Six-month extension - AusNet Services variation decision*, October 2020; AER, *Six-month extension - CitiPower variation decision*, October 2020; AER, *Six-month extension - Jemena variation decision*, October 2020; AER, *Six-month extension - Powercor variation decision*, October 2020; AER, *Six-month extension - United Energy variation decision*, October 2020.

[22] AER, *Six-month extension – AusNet Services variation decision*, October 2020, p. 3; AER, *Six-month extension – CitiPower variation decision*, October 2020, p. 3; AER, *Six-month extension – Jemena variation decision*, October 2020, p. 3; AER, *Six-month extension – Powercor variation decision*, October 2020, p. 3; AER, *Six-month extension – United Energy variation decision*, October 2020, p. 3.

14.4.1.3 Intra-period adjustment to the weighted average cost of capital

Under the CPI-X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. The TAR is updated annually by an X factor which is designed to measure the real rate of change and is applied to reduce revenue variations between years (a revenue smoothing mechanism). The X factor itself is updated annually to incorporate updates to the trailing average cost of debt through the weighted average cost of capital.

Further discussion on this adjustment can be found in:

- Attachment 3—Rate of return—which discusses the trailing cost of debt update, and
- Attachment 1—Annual revenue requirement—which discusses the X factors.

14.4.1.4 Incentive scheme adjustments (I-factor)

The I-factor parameter makes adjustments to the allowed revenue relating to a service provider's performance against relevant incentive schemes.

For the Victorian distributors the annual adjustments relate to incentive scheme payments (rewards or penalties) due to their performance against the service target performance incentive scheme (STPIS), CSIS[23], demand management innovation allowance (DMIA)[24], demand management incentive scheme (DMIS) and f-factor incentive scheme.

For the avoidance of doubt, the I-factor does not incorporate incentive scheme payments already accounted for in our regulatory determination building blocks (such as the capital expenditure sharing scheme or efficiency benefit sharing scheme).

Service target performance incentive scheme (S-factor)

As set out in our draft decision, the Victorian distributors will be subject to the new STPIS guideline for the 2021–26 regulatory control period.[25]

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[23] Jemena has chosen not to apply for the CSIS.

[24] The DMIA will be replaced by the DMIAM, with application of this incentive scheme to occur in the same manner as the DMIA from the 2026-31 regulatory control period.

[25] AER, *Electricity distribution service providers: Service target performance incentive scheme*, November 2018; AER, *Draft decision - AusNet Services distribution determination 2021–26 - Attachment 10 - Service target performance incentive scheme*, September 2020, p. 4; AER, *Draft decision - CitiPower distribution determination 2021–26 - Attachment 10 - Service target performance incentive scheme*, September 2020, p. 4; AER, *Draft decision - Jemena distribution determination 2021–26 - Attachment 10 - Service target performance incentive scheme*, September 2020, p. 4; AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 10 - Service target performance incentive scheme*, September 2020, p. 4; AER, *Draft decision - United Energy distribution determination 2021–26 - Attachment 10 - Service target performance incentive scheme*, September 2020, p. 4.

Under the new STPIS guideline, STPIS payments will be applied through the revenue cap as monetary amounts added to or subtracted from the annual revenue (in line with other incentive schemes).[26] In previous control periods, the STPIS payments were applied as a percentage adjustment to annual revenue.[27]

STPIS payments are typically applied to revenue on a two-year lag. The two-year lag occurs because the Victorian distributors typically submit their compliance reports in the year (year t-1) following the year of performance (year t-2). STPIS payments are then made the in the following year (year t).

For example, a distributor will submit its compliance report in 2023–24 (year t-1) for its performance against the STPIS in 2022–23 (year t-2). STPIS payments are made through the revenue cap for prices that apply in 2024–25 (year t).

Given this lag, there is a transitional phase in the 2021–26 regulatory control period. In years 1 and 2 of the regulatory control period, the STPIS payments would generally be provided as a percentage adjustment to annual revenue. However, to simplify the process for these first two years of the regulatory control period, we will translate the STPIS percentages into equivalent monetary values to be incorporated directly into the I-factor. In subsequent years, any revenue increments or decrements related to the STPIS will be included in the I-factor adjustment as a monetary amount.

The change in STPIS payment method also requires a change in the way the STPIS payments are determined. Previously, STPIS payments were applied as a percentage adjustment to the forthcoming adjusted annual smoothed revenue requirement (year t) as calculated in annual pricing proposals each year.

However, the new guideline determines that the STPIS monetary payments are based on the revenue relevant to the year for which STPIS performance is measured. On this basis, the STPIS payments are determined using the adjusted annual smoothed revenue requirement from year t-2.

For example, the STPIS payment in 2024–25 (year t) will be for performance against the STPIS in 2022–23 (year t-2), and the adjusted annual smoothed revenue requirement for 2022–23 (year t-2) is used to calculate the STPIS payment.[28]

In addition, we note that the transition from calendar to financial years will require an additional adjustment for the first two years.

- For the first year of the 2021–26 regulatory control period (year t=1 or 2021–22), the STPIS payments are expected to include any adjustments relating

[26] AER, *Electricity distribution service providers: Service target performance incentive scheme*, November 2018, pp. 34-35.

[27] AER, *Electricity distribution service providers: Service target performance incentive scheme*, November 2009.

[28] The adjusted annual smoothed revenue requirement in year t=1 is equal to the annual smoothed revenue requirement set in the PTRM. This applies to year t=1 only.

to year t-3 (2019). It is not anticipated this will incorporate adjustments relating to year t-2 (2020) as these are not expected to be available in time.

  - For the second year (year t=2 or 2022–23), the STPIS payments are expected to include any adjustments relating to year t-3 (2020) and year t-2 (first half of 2021).
  - For the third and subsequent years (years t=3 to 5 or 2023–24 onwards), the STPIS payments are expected to revert to including any adjustments relating to year t-2 (e.g. 2021–22 outcomes are applied in 2023–24).

Customer service incentive scheme (H-factor)

We have updated the I-factor definition in the control mechanism formulae to include provision for incentive scheme payments (rewards or penalties) relating to AusNet Services', CitiPower's, Powercor's and United Energy's performance against the CSIS.

AusNet Services, CitiPower, Powercor and United Energy decided to apply the CSIS for the 2021–26 regulatory control period following our publication of the final CSIS in July 2020.[29] In accordance with the CSIS, the four Victorian distributors proposed the I-factor include the annual adjustments relating to performance against the CSIS.[30] [31]

We are able to update this aspect of the control mechanism formulae in our final decision as the F&A paper stated that the definition of the I-factor would be decided in the distribution determination.[32]

The first CSIS payments will occur in the third year of the regulatory control period (2023–24) because the payments are recovered through revenues on a two-year lag from the year of performance against the CSIS. The two-year lag will mean there are no CSIS payments in the first and second years of the regulatory control period.

Jemena has decided not to apply the CSIS for the 2021–26 regulatory control period.[33] See Attachment 12 – Customer service incentive scheme for discussion on the CSIS.

Demand management innovation allowance and incentive scheme

As set out in our draft decisions, the new demand management innovation allowance mechanism (DMIAM) and DMIS will replace the DMIA applied to Victorian distributors from 1 July 2021.[34]

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29 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 142-143.

30 CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

31 AusNet Services did not explicitly propose the CSIS be included in the I-factor, however we note that AusNet Services' January proposal included the H-factor in the I-factor definition (AusNet Services, *Regulatory Proposal 2021–26 Part III,* January 2020, p.269*)*.

32 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 67.

33 Jemena, *2021–26 Revised Regulatory Proposal*, December 2020, p. 28.

To close out the DMIA we will determine and apply any carryover amount from underspending the allowance as a deduction from the distributor's revenue requirement in the 2021–26 regulatory control period.[35]

As a consequence, the I-factor include a component to adjust revenues for the DMIA carryover amount. This adjustment will occur in year 2 of the 2021–26 regulatory control period.

A similar adjustment will be required in year 2 of the 2026–31 regulatory control period for carryover amounts relating to the DMIAM for the 2021–26 regulatory control period.

Consistent with the STPIS and CSIS, payments relating to the new DMIS will occur on a two-year lag from the year of performance and applied in year t.

Due to the early application of the DMIS, the transition from calendar to financial years will require an additional adjustment for the first two years.

- For the first year of the 2021–26 regulatory control period (year t=1 or 2021–22), DMIS payments are expected to include any adjustments relating to year t-3 (2019). It is not anticipated this will incorporate adjustments relating to year t-2 (2020) as these are not expected to be available in time.
- For the second year (year t=2 or 2022–23), DMIS payments of the I-factor is expected to include any adjustments relating to year t-3 (2020) and year t-2 (first half of 2021).
- For the third and subsequent years (years t=3 to 5 or 2023–24 onwards), DMIS payments are expected to revert to including any adjustments relating to year t-2 (e.g. 2021–22 outcomes are applied in 2023–24).

f-factor incentive scheme (f-factor)

The fire start (f-factor) incentive scheme provides incentives to the Victorian distributors to reduce the risk of fire starts due to electricity infrastructure, and to reduce the risk of loss or damage caused by fire starts.[36] We have made an f-factor scheme determination for each of the Victorian distributors under the F-Factor Scheme

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[34] AER, *Demand management incentive scheme*, November 2017; AER, *Explanatory Statement, Demand management incentive scheme*, November 2017; AER, *Demand management innovation allowance mechanism*, November 2017; AER, *Explanatory statement, Demand management innovation allowance mechanism*, November 2017; AER, *Demand management incentive scheme, Electricity distribution network service providers*, December 2017; AER, *Draft decision - AusNet Services distribution determination 2021–26 - Attachment 11 - DMIS and DMIAM*, September 2020, p. 3; AER, *Draft decision - CitiPower distribution determination 2021–26 - Attachment 11 - DMIS and DMIAM*, September 2020, p. 3; AER, *Draft decision - Jemena distribution determination 2021–26 - Attachment 11 - DMIS and DMIAM*, September 2020, p. 3; AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 11 - DMIS and DMIAM*, September 2020, p. 3; AER, *Draft decision - United Energy distribution determination 2021–26 - Attachment 11 - DMIS and DMIAM*, September 2020, p. 3.

[35] AER, *Final decision: CitiPower distribution determination 2016 to 2020, Attachment 12 – Demand management incentive scheme*, May 2016; AER, *Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy*, April 2009, p. 8–9.

[36] AER, *Final determination - f-factor for Victorian electricity distribution network service providers*, June 2017, p. 16.

Order in respect of the 2021–26 regulatory control period. Discussion on our f-factor scheme determinations is set out in the Overview chapter.

The f-factor incentive scheme previously operated on a 2½ year lag. That is, it is applied in the regulatory year commencing 18 months after the performance year ends (e.g. 2017–18 performance was applied as an adjustment to the 2020 revenue allowance).

With the transition to regulatory years on a financial year basis, the f-factor will be better aligned and operate on a three-year lag in the 2021–26 regulatory control period (e.g. 2018–19 performance will be applied as an adjustment to the 2021–22 revenue allowance). The three-year lag reflects that smaller timed lags (e.g. a two-year lag) are not feasible due to the required timeframes for determining the f-factor adjustment. This three-year lag is provided under the Victorian F-Factor Scheme Amendment Order 2020, which amended the F-factor scheme Order 2016.[37]

CitiPower, Powercor, and United Energy expressed concern that applying the f-factor on a three-year lag on a permanent basis would dilute incentives.[38] However, due to the processes required to calculate the f-factor, including those undertaken by external parties, the timelines do not allow for a shorter lag on this incentive scheme.

Unlike the other scheme payments, transitional adjustments are not required for the f-factor due to the timing of moving to a three-year lag at the same time as the transition from calendar to financial years.

14.4.1.5 Annual adjustments (B-factor)

In accordance with the F&A, the annual adjustment factors to be included in the B-factor are decided in our distribution determination.[39]

The B-factor parameter makes adjustments to the revenue cap required within the 2021–26 regulatory control period. Consistent with our final F&A the B-factor will include 'true-up' adjustments for DUoS revenue under or over recovery and adjustments relating to Essential Service Commission Victoria (ESCV) licence fees.[40]

Unders and overs account

Our final decision is the B-factor will include a true-up for the net present value of under or over recovered revenue. This true-up will be calculated based upon the DUoS unders and overs account in accordance with the method in Appendix A.

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37 Victoria Government Gazette S 549, 27 October 2020, p. 30 - http://www.gazette.vic.gov.au/gazette/Gazettes2020/GG2020S549.pdf.

38 CitiPower, Powercor, United Energy, *Correspondence on price control formula,* 5 December 2019,.

39 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 67.

40 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 67.

Under a revenue cap, the Victorian distributors' revenues in year t will be adjusted annually to clear (or true-up) any under or over recovery of actual revenue collected through DUoS charges in year t–2 (and/or t–3 where applicable) and any estimated under or over recovery of revenues in year t–1 (and/or t–2 where applicable).

Appendix A sets out that the unders and overs account for the first two years of the 2021–26 regulatory control period will incorporate an additional year to account for:

- the transition to regulatory years on a financial year basis, and
- prices for the first half of 2021 included no adjustments for DUoS under or over recovery amounts.

For any regulatory year–t, we base the level of this adjustment on the opening balance of the DUoS unders and overs account.

The under or over-recovery adjustment in year t will be adjusted by six months of the approved weighted average cost of capital (WACC) to reflect the time value of money of this adjustment. This reflects that the balance would generally be adjusted for twelve months of WACC if it was carried forward, and that the under or over-recoveries that arise within the year are adjusted by six months of WACC.

The WACC applied in the unders and overs account will be sourced from the annual return on debt updates provided by the AER and adjusted for actual inflation.[41] This is to be known as the adjusted nominal WACC.

Presentation of adjustments in the unders and overs account

In the unders and overs account, the sign of the true-up should be the reverse of the sign of the opening balance. This treatment is to demonstrate that the purpose true-up is to offset the opening balance. For clarity, if a distributor has under recovered its allowable revenue prior to year t, this balance will be negative. Therefore the true-up will be presented as a positive amount to allow the distributor to bring the balance of the unders and overs account to zero.[42]

As the unders and overs account determines the true-up amount to be included in the B-factor for determining the TAR, the B-factor in the unders and overs account is expected to be zero where there are no defined annual adjustments, or equal to the sum of those defined annual adjustments (see below further components of B-factor)).

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41 If circumstances require, alternative adjustments for an appropriate cost of capital may be applied following consultation between the AER and relevant distributor(s).

42 The balance of the unders and overs account is to be below zero to ensure compliance with the revenue cap. For more detail see Appendix A of this attachment.

Licence fees (L-factor)

Our final decision B-factor includes an L-factor adjustment to allow the Victorian distributors to recover the licence fees they are charged by the ESCV. The operation of the L-factor is set out in section 14.4.5.

As ESCV licence fees are applied on a financial year basis there is no transitional treatment to be considered. These ESCV fees are applied on a two-year lag.

Energy Safe Victoria (ESV) levies

In their revised proposals, the Victorian distributors proposed the Energy Safe Victoria (ESV) levies also be recovered through the B-factor, in line with the current treatment of ESC licence fees.[43]

However, on 25 February 2021, CitiPower, Powercor and United Energy requested the AER to determine that the scheme established by section 8 of the Electricity Safety Act 1998 (Vic) is a jurisdictional scheme.[44] Under the scheme, known as the ESV Levy Scheme, the Victorian distributors must pay levies to ESV in respect of its reasonable costs and expenses, as determined by the Victorian Minister.[45]

On 19 March 2021, we determined the ESV Levy Scheme to be a jurisdictional scheme which applies to all Victorian distributors.

The Victorian distributors are required under the distribution determinations to report to the AER the recovery of the ESV Levy Scheme amounts and on adjustments to be made to pricing proposals for over or under recovery, as set out in section 14.4.3. As a result, the ESV Levy Scheme becomes an approved jurisdictional scheme for the Victorian distributors, and the ESV levies are no longer part of the distribution revenues.

Further consideration of the ESV levies is covered in Attachment 6 – Operating expenditure.

Australian Energy Market Operator fees

The Victorian distributors also proposed that AEMO fees that may commence within the 2021–26 regulatory control period be recovered through the B-factor.[46] This is in

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43 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 173; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Jemena, *Attachment 05-01 - Operating expenditure*, December 2020, pp. 30-31; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26* December 2020, p. 58.

44 CitiPower, Powercor and United Energy, *Request for jurisdictional scheme determination*, February 2021.

45 Electricity Safety Act 1998 (Vic), Section 8.

46 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 173; CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 62; Jemena, *Attachment 07-01 - Price control mechanisms*, December 2020, pp. 2–4; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

response to AEMO's draft report on Electricity Fee Structure which proposed to introduce electricity participant fees for distributors from 1 July 2023.[47]

However, on 26 March 2021, AEMO published its final report on Electricity Fee Structure which determined that electricity distributors will not be charged participant fees for the next fee period. AEMO will monitor the distributors' involvement with AEMO's systems and processes throughout the next fee period and review its position if required.[48]

As a result of AEMO's final report there is no need to include these fees in the B-factor. We note AusNet Services updated revised proposal proposed the recovery of potential AEMO fees as an opex step change.[49] If an AEMO fee is introduced in future, we consider the costs be treated consistently across all distributors to the extent possible.

Smoothing of material COVID-19 under-recoveries (P-factor)

Our final decision is to allow CitiPower to smooth its recovery of under-recovered distribution revenues in 2020 due to significantly reduced electricity consumption caused by the COVID-19 pandemic. We have not made provision for smoothing of under or over recovered revenues for the other Victorian distributors as their distribution revenues in 2020 were not materially impacted.

The total amount to be smoothed will be determined in CitiPower's 2021–22 pricing proposal and recovered in equal amounts over the remaining four years of the regulatory control period (2022–26) to reduce price impacts for customers. These amounts will be subject to adjustments to reflect the time value of money in line with those made in the unders and overs account.

We typically do not allow distributors to defer or smooth recovery of revenues into future years. In our experience, the risks involved (such as a snowballing effect of continued and increased under recoveries) outweigh the benefit of smoothing the impact, as the impact can then be exacerbated (larger price shocks).

However, we consider that in exceptional circumstances that deferrals or smoothing of revenue recovery can be allowed. In making these decisions, we take into consideration the impacts to both the distributors and, importantly, customers.

In 2020, Victorian electricity consumption changed as a result of the response to the exceptional circumstances created by the COVID-19 pandemic. This was due to state wide restrictions which had economic and social changes, including large numbers of the population working from home and business closures.

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47 AEMO, *Draft Report and Determination, Electricity Fee Structures*, November 2020.

48 AEMO, *Final Report and Determination, Electricity Fee Structures*, March 2021, pp. 5, 26.

49 AER, *Final decision, AusNet Services distribution determination 2021–26, Attachment 6, Operating expenditure, section 6.4.3 - AEMO fees*, April 2021.

Of the Victorian distributors, CitiPower was most impacted as its network is primarily the Melbourne central business district, and therefore energy consumption was affected by office and business closures.

In their revised proposals, CitiPower, Powercor, and United Energy proposed that distributors be allowed to defer recovery of under recovered revenues in 2020 due to the COVID-19 pandemic by up to four years to assist in smoothing the impact.[50] CitiPower's revised proposal expected an under-recovery of 5 per cent of its distribution revenue in 2020.[51]

To better understand these impacts, we issued information requests to the Victorian distributors seeking best estimates of their under or over recovery of revenues in 2020. Our analysis of the Victorian distributors' responses showed that only CitiPower's customers would incur substantive price increases should the recovery of under/over recovered revenue be passed through to customers in just one year.

In undertaking our analysis, we took into consideration other factors such as impacts and/or offsetting amounts regarding recovery of previous under or over recovered designated pricing proposal charges or jurisdictional schemes revenues.

As a result, our final decision is to allow CitiPower to smooth the recovery of it's under recovered distribution revenues over the regulatory control period as follows:

- The smoothing will only apply to distribution revenue. Under-recoveries experienced in other accounts are expected to be immaterial or offset by other factors.
- CitiPower will propose the total amount to be recovered in future years in its 2021–22 pricing proposal for the AER's approval. The amount proposed will be calculated as the difference between actual revenue and the total allowable revenue set for 2020, inclusive of relevant unders/overs adjustments for that year.
- The total amount to be recovered will be set as four equal amounts over the remaining four years of the regulatory control period (2022–26).
- The amounts to be recovered in the remaining years will be indexed using the WACC (see Section 14.4.5 for formulae), including a half year WACC in 2020 that is usually applied in the unders/overs account (and any relevant adjustments to consider the 2021 six-month extension period).

We will consider the proposed smoothing and compliance with requirements set in the determination at the time of reviewing the 2021–22 pricing proposal. No additional

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50 CitiPower, *Revised regulatory proposal 2021–26,* December 2020, p. 62; Powercor, *Revised regulatory proposal 2021–26*, December 2020, p. 72; United Energy, *Revised regulatory proposal 2021–26*, December 2020, p. 58.

51 CitiPower, *Revised regulatory proposal 2021–26*, December 2020, p. 31.

adjustments or smoothing of these under-recovered revenues will be allowed over the remaining four years of the regulatory control period.[52]

Deliberate under-recovered revenue

If a distributor chooses, in its own interests, to under-recover revenue, then this is to be considered a deliberate under-recovery. These types of under-recoveries will be forgone by the distributor and not recovered in future years. We have made provision for the treatment of deliberate under-recoveries in the unders and overs account in Appendix A of this attachment.

Our approach for the treatment of deliberate under-recovered revenue was set out in our F&A,[53] and is consistent with our recent regulatory determinations for distributors in other NEM jurisdictions.

Deliberate under-recoveries are in contrast to those that arise due to variations between forecast of a services offered and actual quantities achieved (whether natural or set through some mechanism or clause in the tariff structure statements). The impact on revenues (under or over recovery) from variations between forecasts and actual quantities is accounted for in the unders and overs accounts. The treatment of these types of under and over recoveries ensure distributors never recover more or less revenue over the long term in net present terms.

Furthermore, we do not intend the treatment of intentional under-recoveries to impede distributors from proposing dynamic charging structures in tariff structure statements.

Treatment of AusNet Services' waiving of critical peak demand charges at the request of customers

In response to our draft decision, AusNet Services noted at times, at the request of a customer, it waives critical peak demand charges where the customer has been unable to respond to a critical peak demand event for reasons out of their control (such as a force majeure event).[54] In these instances, AusNet Services has not recovered the revenues it would otherwise be allowed.

AusNet Services noted the practice to waive critical peak demand charges in these instances are consistent with its tariff structure statement and proposed the revenues it otherwise would have recovered not be treated as a deliberate under recovery.[55]

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52 The calculation of the amount to be smoothed and subsequent adjustments in remaining years will be calculated through the mechanisms set by the AER in the Victorian Tariff Approval Model.

53 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 64-65.

54 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 173-174; AusNet Services, *Response to information request 74 - Q1, 2 and 4*, 11 February 2021.

55 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 173-174.

We agree with AusNet Services that this practice is consistent with its approved tariff structure statement and that the revenues it otherwise would have recovered not be treated as deliberate under recovered revenues.

We observe the difference in revenue is due to how the charges are calculated rather than a deliberate decision to under recover revenue. Specifically, AusNet Services excludes the specific day, at the request of the customer, in determining the critical peak demand charges and revenue.[56] So, for example, instead of using the average peak demand based on 5 days it calculates it based on 4 days.

In response to our information request, AusNet Services noted these requests are low frequency (three, over the 2016–20 regulatory control period) and relate to low values (a total of less than $70,000).[57] In making our decision, we have taken into consideration the low frequency of requests and low value impacts. We will continue to monitor the treatment and impacts of this practice over the 2021–26 regulatory control period to be reviewed for AusNet Services next distribution determination.

14.4.1.6 Cost pass through adjustments (C-factor)

The C-factor is for annual TAR adjustments relating to AER-approved cost pass through amounts, and can also include AER-approved end-of-period adjustments. These could include once-off adjustments to revenue required during the 2021–26 regulatory control period that are not able to be accounted for in the other factors of the revenue cap formula.

For the avoidance of doubt, end of period adjustments (positive or negative) may only − and must − be included in the C-factor where the AER has decided to apply a given adjustment (for example, as part of a regulatory determination).

In the first year (2021–22) of the 2021–26 regulatory control period, the C factor will include an adjustment to true-up the allowed revenue amounts we set for the six-month extension period. We used a placeholder WACC to determine the allowed revenues for the six-month extension period. Now that the updated WACC has been determined for this period using the averaging periods nominated by the DNSPs and approved by the AER, an adjustment is required to account for the differences between the placeholder and updated WACCs. The true-up for the placeholder WACC is discussed further in Attachment 3 – Rate of return.

The true-up adjustment for the six-month extension period relates to revenues recovered in the six-month extension period, being 1 January 2021 - 30 June 2021. The true-up adjustment will be applied to revenues in the 2021–22 year. Therefore, the adjustment amount will be indexed by the relevant half year WACC to account for the time-value of money between these periods.

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56 AusNet Services, *Response to information request 74 - Q1, 2 and 4*, 11 February 2021.

57 AusNet Services, *Response to information request 74 - Q3a*, 11 February 2021; AusNet Services, *Response to information request 74 - Q3b*, 17 February 2021.

More detail on the types of costs that can be included as a cost pass through are set out in Attachment 15 – Pass through events.

14.4.1.7 Calculation of movements in the consumer price index

We will apply the annual movement between the Australian Bureau of Statistics' (ABS) published December quarter data to calculate the change in CPI for the control mechanism formula.

Use of the December quarter data will mean the Victorian distributors will apply an actual CPI escalation (rather than an estimated or 'placeholder' CPI escalation) when they submit their pricing proposals. The use of an actual CPI escalation will allow the process for setting prices to be more transparent, which is consistent with the intent of the pricing rule provisions.[58]

Historically, the Victorian distributors have used June CPI, which is what was included in our F&A for the Victorian distributors.[59] Due to the change to regulatory years on a financial year basis, we consider a material change in circumstances has occurred, warranting a departure from the F&A.

As the Victorian distributors' regulatory years will be consistent with the rest of the NEM, we consider the approach to determining CPI movements should also be consistent. The December quarter data is the latest CPI data available at the time the Victorian distributors submit their annual pricing proposals during the 2021–26 regulatory control period.

The application of this calculation is set out in Figure 14.1.

14.4.2 Reporting on designated pricing proposal charges

We must decide how the Victorian distributors will report on the recovery of designated pricing proposal charges[60] for each year of the 2021–26 regulatory control period and on the adjustments to be made to account for under or over recovery of those charges.[61]

We apply an under and over recovery mechanism to facilitate this reporting. This approach is similar to the DUoS revenue under and over recovery mechanism and is

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58 NER, cl. 6.18.5 (g)(3).

59 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 67-68.

60 Designated pricing proposal charges are charges related to: designated pricing proposal services (prescribed exit fees, prescribed common transmission services and prescribed transmission use of system services); avoided customer transmission use of system charges; charges provided by another distributor (but only to the extent they comprise of designated pricing proposal services or standard control services); and charges or payments related specified in NER clause 11.39.

61 NER, cl. 6.12.1 (19).

consistent with the requirements of the National Electricity Rules (NER).[62] The operation of this method is detailed in Appendix C of this attachment.

14.4.3 Reporting on jurisdictional scheme amounts

We must decide how the Victorian distributors will report on the recovery of jurisdictional scheme amounts for each year of the 2021–26 regulatory control period and on the adjustments to be made to account for under or over recovery of those charges.[63]

Our draft decision jurisdictional scheme amounts under and over recovery mechanism approach is consistent with the requirements of the NER.[64] It is also consistent with the approach applied to electricity distributors in other jurisdictions. The operation of this method is detailed in Appendix D of this attachment.

14.4.4 Rounding of inputs in annual pricing proposal process

When reporting on compliance as part of the annual pricing proposal process each year of the 2021–26 regulatory control period, we require that certain calculation inputs be used on an unrounded basis while others may be used on a rounded basis.

The process for rounding and the specific inputs to be rounded are detailed in Appendix F of this attachment.

14.4.5 Control mechanism formulae for standard control services

Our final decision control mechanism formulae must be as set out in the F&A unless we consider that a material change in circumstances justifies departing from that approach.[65] Figure 14.1 sets out the revenue cap formula for distribution services.

For standard control services, the NER require the control mechanism be of the prospective CPI–X form (or some incentive-based variant).[66]

As discussed in our draft decision, we have amended the control mechanism formulae from that in the F&A to account for recent changes to the STPIS.[67] Namely, the change

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[62] NER, cll. 6.12.1(19), 6.18.7.

[63] NER, cl. 6.12.1 (20).

[64] NER, cl. 6.18.7A.

[65] NER, cl. 6.12.3(c1).

[66] NER, cl. 6.2.6(a).

[67] AER, *Draft decision - AusNet Services distribution determination 2021–26 - Attachment 14 - Control mechanisms* September 2020, pp. 10-11; AER, *Draft decision - CitiPower distribution determination 2021–26 - Attachment 14 - Control mechanisms,* September 2020, pp. 10-11; AER, *Draft decision - Jemena distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 10-11; AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 10-11; AER, *Draft decision -*

will see the annual STPIS adjustments be applied as a fixed monetary amount rather than a percentage adjustment as has been the most recent application.

Figure 14.1 Revenue cap formula[68]

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 and t = 1,2…,5

2. $$TAR_t = AAR_t + I_t + B_t + C_t$$ t = 1,2...,5

3. $$AAR_t = AR_t$$ t = 1

4. $$AAR_t = AAR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$ t = 2,3…,5

where:

TAR_t is the total allowable 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. Likely to incorporate revenue adjustments relating to outcomes of:

- the f-factor incentive scheme in relation to financial year t-3 to be applied in years t=1 to 5 (e.g. 2018–19 f-factor to be applied in 2021–22)
- the STPIS[69] [70] (S-factor) in relation to:

United Energy distribution determination 2021–26 - Attachment 14 - Control mechanisms, September 2020, pp. 10-11.

68 All parameters are in nominal terms unless otherwise specified.

69 The service target performance incentive scheme (STPIS) version 2.0 applies for the 2021–26 regulatory control period. The first payments relating to STPIS version 2.0 will occur in 2023/24. See *AER, Electricity distribution network Service Providers - Service target performance incentive scheme (Version 2.0)*, November 2018. In years

- regulatory year t-3 to be applied in years t=1,2 (i.e. 2019 STPIS to be applied in 2021–22, 2020 STPIS to be applied in 2022–23)
- regulatory year t-2 to be applied in years t=2 to 5 (i.e. 2021 6-month STPIS to be applied in 2022–23, 2021–22 STPIS to be applied in 2023–24, and so on).[71]

○ the CSIS (H-factor) in relation to financial year t-2[72]

○ the demand management incentive scheme (DMIS) in relation to:

- regulatory year t-3 to be applied in years t=1,2 (i.e. 2019 DMIS to be applied in 2021–22, 2020 DMIS to be applied in 2022–23)
- regulatory year t-2 to be applied in years t=2 to 5 (i.e. 2021 6-month DMIS to be applied in 2022–23, 2021–22 DMIS to be applied in 2023–24, and so on).[73]

○ any amounts required to true-up the demand management innovation allowance (DMIA) in relation to the 2016–20 regulatory control period[74] to be applied in regulatory year t=2 only[75]

○ any other related incentive schemes as applicable[76] that are to be applied in year t.

B_t is the sum of annual adjustment factors for year t. It includes:

○ the true-up for any under or over recovery of actual revenue collected through DUoS charges calculated using the following method:

$$DUoS\ Under\ and\ Overs\ True-Up_t = -(Opening\ Balance_t)(1+WACC_t)^{0.5}$$

where:

$DUoS\ Under\ and\ Overs\ True-Up_t$ is the true-up for the balance of the DUoS unders and overs account in year t.

2021/22 and 2022/23, the payments relating to STPIS will be translated into a monetary amount for application under the I factor.

70 The STPIS 2.0 guideline uses the annual smoothed revenue AR(t-2) in the calculation of the s-factor, however AR is only applicable to revenue in the first year of the regulatory control period when revenue is sourced from the PTRM. AR(t-2) will apply to the s-factor calculations in year t=3, as this refers to the first year revenue. In other years where STPIS 2.0 applies (in this regulatory control period, years t=4 and 5), AAR(t-2) will be used to ensure the correct revenue is used, inclusive of actual CPI movements.

71 In the year 2022–23, the STPIS performance outcomes for both the 2020 year and the 2021 six-month extension period will be applied.

72 As the CSIS is a new scheme in the 2021–26 regulatory control period, no transitional approach is required.

73 In the year 2022–23, the DMIS performance outcomes for both the 2020 year and the 2021 six-month extension period will be applied.

74 The DMIA measurement will be extended to incorporate the 2021 six-month extension period.

75 The DMIA will be replaced by the demand management innovation allowance mechanism (DMIAM) from 1 June 2021, and will be applied in year 2 of the 2026–31 regulatory control period.

76 This does not reflect those incentive schemes that are calculated and applied through our regulatory determination, such as the capital expenditure sharing scheme (CESS) or efficiency benefit sharing scheme (EBSS).

$Opening\ Balance_t$ is the opening balance of the DUoS unders and overs account in year t as calculated by the method in Appendix A.

$WACC_t$ is the approved weighted average cost of capital (WACC) used in regulatory year t in the DUoS unders and overs account in Appendix A. This WACC figure will be as approved by the AER for the relevant year.

- licence fee charges incurred by the Victorian businesses, charged by the Essential Services Commission Victoria (ESCV). The recovery of these charges will occur on a two-year lag, and will therefore be indexed by two years interest, calculated using the following method:

$$L_{t-2} \times (1 + WACC_t) \times (1 + WACC_{t-1})$$

where:

L_{t-2} is the sum of the licence fees paid by the distributor to the ESCV relating to regulatory year t-2.

In year t=1 (i.e. 2021–22), the t-1 period will be the six-month extension period with the nominal WACC reflecting only the first six months of 2021. To index the licence fee charges for a full year, the nominal WACC for the t-2 period will be included in the calculation using the following method:

$$L_{2019\text{-}20} \times (1 + WACC_{2021\text{-}22}) \times (1 + WACC_{2020\text{-}21}) \times (1 + WACC_{2019\text{-}20})^{0.5}$$

- in the case of CitiPower, an adjustment to smooth distribution revenues being under-recovered in 2020 as a result of COVID-19 impacts.[77] These adjustments relate to 2020 under-recovered revenue that is smoothed over a number of years, and will therefore be indexed by an appropriate amount of interest, calculated using the following method:

$$P_t \times (1 + WACC_t)^{0.5} \times (1 + WACC_{t-1}) \ \times \ldots \times \ (1 + WACC_{HY21}) \times (1 + WACC_{2020})^{0.5}$$

where:

P_t is the annual adjustment amount for the 2022–26 years to smooth out the under-recovery for 2020, as approved in the 2021–22 pricing proposal.

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 regulatory year t.

[77] Further explanation can be found in Section 14.4.1.5.

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities[78] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t is the X factor for each year of the 2021–26 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3—rate of return—calculated for the relevant year.

Side constraints

For each regulatory year after the first year of a regulatory control period, the Victorian distributors are subject to side constraints which limits the annual movements in revenue that can be recovered from a tariff class.

The specific requirement is that the expected weighted average revenue to be raised from a tariff class must not exceed the corresponding expected weighted average revenue for the preceding year by more than the permissible percentage.[79] In accordance with the NER, the permissible percentage increase is the greater of CPI–X plus 2 per cent or CPI plus 2 per cent.[80]

The NER states that recovery of certain revenues, such as cost pass through amounts, are to be disregarded in deciding whether the permissible percentage has been exceeded.[81] Therefore, we adjust the permissible percentage by the annual movement in such revenues to remove (disregard) their impact for determining compliance with the side constraints.

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78 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

79 NER, cl. 6.18.6.

80 NER, cl. 6.18.6(c).

81 NER, cl. 6.18.6(d).

Figure 14.2 Side constraints formula[82]

For t = 2, 3,…,5:

$$\frac{\left(\sum_{i=1}^{n}\sum_{j=1}^{m}p_t^{ij}q_t^{ij}\right)}{\left(\sum_{i=1}^{n}\sum_{j=1}^{m}p_{t-1}^{ij}q_t^{ij}\right)} \leq (1+\Delta CPI_t)\times(1-X_t)\times(1+2\%)+I_t^{\prime}+B_t^{\prime}+C_t^{\prime}$$

where each tariff class has "n" tariffs, with each up to "m" components, and where:

p_t^{ij} is the proposed price for component ‘j’ of tariff 'i' for year t.

p_{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 tariff 'i' in year t.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[83] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t is the X factor for each year of the 2021–26 regulatory control period as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in Attachment 3—rate of return—calculated for

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82 All parameters are in nominal terms unless otherwise specified.

83 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

I_t' is the annual percentage change in the sum of incentive scheme adjustments described in Figure 14.1 applied in year t.

B_t' is the annual percentage change from the sum of annual adjustment factors for year t and includes true-up for any under or over recovery of actual revenue collected through DUoS charges calculated using the method in Figure 14.1.

C_t' is the annual percentage change from 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 regulatory year t.

With the exception of the CPI and X factor, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

14.5 Reasons for final decision on alternative control services

The following sets out the reasons for our final decision on the control mechanism formulae for alternative control services. This reasoning is provided in relation to the relevant control mechanism formula parameters.

In our final F&A, we set out our decision to apply a revenue cap to type 5 and 6 (inc. smart metering) services and price caps to all other alternative control services.[84]

As noted, the forms of the control mechanisms that will apply to a distribution determination and the formulae that give effect to those control mechanisms are considered during the F&A stage.[85] We have limited discretion to depart from the control mechanisms set out in the F&A paper.[86] For example, we can only depart from the formulae if there has been a material change in circumstance.

In their initial proposals, the Victorian distributors proposed formulae for alternative control services for the 2021–26 regulatory control period that generally reflected the F&A paper, with the exception of the control mechanism for price-capped services

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[84] AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 54.

[85] AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 54–73.

[86] NER, cl. 6.12.3(c) and (c1).

provided on a quoted basis.[87] The Victorian distributors proposed adjustments to this quoted price cap formula to incorporate a tax element, or a tax element and a margin element.[88]

Our draft decision did not accept the inclusion of tax and margin elements on the basis the Victorian distributors had not provided sufficient information to demonstrate that a material change in circumstance justified varying the formulae set in the F&A.[89] [90]

For our final decision, we do not consider the Victorian distributors have provided any further information that would substantiate a material change in circumstance has occurred to depart from the binding formulae set in the F&A. Our final decision is to maintain our draft decision, and not include a tax or margin element in the quoted services formula.

14.5.1 Application of the control mechanism formulae for type 5 and 6 (inc. smart metering) services

Consistent with our final F&A, our final decision revenue cap formula that will apply to the Victorian distributors' type 5 and 6 (inc. smart metering) services is below.[91]

In the first two years (2021–22, 2022–23) of the 2021–26 regulatory control period, the unders and overs account for type 5 and 6 (inc. smart metering) services will include an additional year (year t-3) adjustment to accommodate the transition to regulatory years on a financial year basis.

In addition, in the first year (2021–22) of the 2021–26 regulatory control period, the C factor will include an adjustment to true-up the allowed revenue amounts we set for the six-month extension period. We used a placeholder WACC to determine the allowed revenues for the six-month extension period. Now that the updated WACC has been determined for this period, an adjustment is required to account for the

87 AusNet Services, *Regulatory Proposal 2021–26 Part III*, January 2020, p.267; CitiPower, *APP08 - Price control formula*, January 2020, pp. 2-8; Jemena, *Attachment 07-07 - Price control mechanisms*, January 2020, p. 1; Powercor, *APP08 - Price control formula*, January 2020, pp. 2-8; United Energy, *APP08 - Price control formula*, January 2020, pp. 3-9.

88 AusNet Services, *Regulatory Proposal 2021–26 Part IV*, January 2020, pp. 59-60; CitiPower, *APP08 - Price control formula*, January 2020, p. 8; Jemena, *Attachment 07-07 - Price control mechanisms*, January 2020, pp. 9-11; Powercor, *APP08 - Price control formula*, January 2020, p. 8; United Energy, *APP08 - Price control formula*, January 2020, p. 9.

89 NER, cl. 6.12.3(c1).

90 AER, *Draft decision - AusNet Services distribution determination 2021–26 - Attachment 14 - Control mechanisms* September 2020, pp. 33-36; AER, *Draft decision - CitiPower distribution determination 2021–26 - Attachment 14 - Control mechanisms,* September 2020, pp. 33-36; AER, *Draft decision - Jemena distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-36; AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-36; AER, *Draft decision - United Energy distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-36.

91 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 72-73.

differences between the placeholder and actual WACCs. This is the same approach applied for standard control services (see section 14.4.1.6).

The true-up amount is set out in Attachment 16 – Alternative control services. The true-up for the placeholder WACC is discussed further in Attachment 3 – Rate of return.

The true-up adjustment for the six-month extension period relates to revenues recovered in the six-month extension period, being 1 January 2021 – 30 June 2021. The true-up adjustment will be applied to revenues in the 2021–22 year. Therefore, the adjustment amount will be indexed by the relevant half year WACC to account for the time-value of money between these periods.

We have also adjusted the calculation of the annual movement in CPI to reflect the change to financial years. The approach to calculate CPI movements are is set out in section 14.4.1.7. The application of this calculation is set out in Figure 14.3.

We have also maintained our draft decision corrections to the revenue cap formula.

Our F&A incorrectly stated the formula to calculate the annual revenue requirement in years t=2, 3, 4, 5 also applies in year t=1. However, consistent with the 2016–20 regulatory control period, the annual revenue requirement in year t=1 is set in our regulatory determination, and no adjustment is required.

Figure 14.3 Revenue cap formula to apply to the Victorian distributors' type 5 and 6 (inc. smart metering) services

$$TARM_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^i q_t^i$$

i = 1,…,n and t = 1, 2…,5

$$TARM_t = AR_t + T_t + B_t + C_t$$

t = 1, 2...,5

$$AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

t = 2, 3, 4, 5

where:

$TARM_t$ is the total allowable revenue for type 5 and 6 (inc. smart metering) services in year t.

p_t^i is the price of component 'j' of tariff 'i' in year t.

q_t^i 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 for year t. In year t=1, the annual smoothed revenue requirement is set in our final decision PTRM.

AR_{t-1} is the annual smoothed revenue requirement approved for year t-1.

T_t is the adjustments in year t for true-ups relating to the Victorian AMI roll-out between 2009 and 2015. There are no adjustments expected for the 2021–26 regulatory control period, and therefore the T factor will have a value of 0.

B_t is the sum of annual adjustment factors for year t and includes the true-up for any under or over recovery of actual revenue collected through type 5 and 6 (inc. smart metering) charges calculated using the following method:

$$Metering\ Unders\ and\ Overs\ True-Up_t = -(Opening\ Balance_t)(1+WACC_t)^{0.5}$$

where:

$Metering\ Unders\ and\ Overs\ True-Up_t$ is the true-up for the balance of the type 5 and 6 (inc. smart metering) services unders and overs account in year t.

$Opening\ Balance_t$ is the opening balance of the type 5 and 6 (inc. smart metering) services unders and overs account in year t as calculated by the method in Appendix B.

$WACC_t$ is the approved weighted average cost of capital used in regulatory year t in the type 5 and 6 (inc. smart metering) services unders and overs account in Appendix B. This WACC figure will be as approved by the AER for the relevant year.

C_t is the sum of approved cost pass through amounts (positive or negative) attributed to these metering services with respect to regulatory year t, as determined by the AER. It will also include any applicable end-of-period adjustments in regulatory year t.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[92] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by

92 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t is the X factor for each year of the 2021–26 regulatory control period as determined in the metering PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3—rate of return—calculated for the relevant year. This annual update of the metering PTRM will be provided alongside (or prior to) the pre-populated pricing model template prior to submission of the annual pricing proposal each year.

Side constraints

Our final decision is that side constraints should apply to the prices for each metering service, for each regulatory year after the first year of the 2021–26 regulatory control period. Our final decision side constraints formula is set out in Figure 14.4.

We have determined the side constraint consistent with the approach defined by the NER for standard control services. That is, the annual permissible percentage increase is the greater of CPI–X plus 2 per cent or CPI plus 2 per cent. The recovery of certain revenues, such as those to accommodate pass throughs and under/over-recoveries, will be disregarded in deciding whether the permissible percentage has been exceeded.[93]

However, as metering prices are charged to each class of meter and not at any lower level of categorisation, side constraints will be measured against the price movements, rather than weighted averages of revenues within a class of services (as per distribution charges).

We note that there is no requirement in the NER for a side constraint on any alternative control service, however we consider it is appropriate for a side constraint mechanism to be applied where a revenue cap is in place. This provides protections for consumers from movements in individual metering prices that are significantly above the average price movement resulting from the use of the revenue cap.

This approach is consistent with the inclusion of a side constraint mechanism for type 5 and 6 (inc. smart metering) services in the Victorian distributors' 2016–20 regulatory control period. The F&A did not address side constraints for type 5 and 6 (inc. smart metering) services, however applying this side constraint mechanism is not inconsistent with the F&A.

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93 NER, cll. . 6.18.6(c) and 6.18.6(d).

Figure 14.4 Side constraints formula[94]

For t=2, 3, 4, 5:

$$\frac{p_t^i}{p_{t-1}^i} \le (1 + \Delta CPI_t) \times (1 - X_t) \times (1 + 2\%) + T_t' + B_t' + C_t'$$

where:

p_t^i is the proposed price for tariff 'i' for year t.

p_{t-1}^i is the price charged for tariff 'i' in year t–1.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[95] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t is the X factor for each year of the 2021–26 regulatory control period as determined in the metering PTRM, and annually revised for the return on debt update in accordance with the formula specified in attachment 3—rate of return—calculated for the relevant year. This annual update of the metering PTRM will be provided alongside (or prior to) the pre-populated pricing model template prior to submission of the annual pricing proposal each year.

T_t is the annual percentage change from the sum of the annual adjustment factors for year t relating to the Victorian AMI roll-out between 2009 and 2015. There are no adjustments expected for the 2021–26 regulatory control period, and therefore the T-factor will have a value of 0.

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94 All parameters are in nominal terms unless otherwise specified.

95 If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

$B_t^{'}$ is the annual percentage change from the sum of annual adjustment factors for year t and includes true-up for any under or over recovery of actual revenue collected through type 5 and 6 (inc. smart metering) services charges calculated using the method in Figure 14.3.

C_t^{i} is the annual percentage change from the sum of approved cost pass through amounts (positive or negative) attributed to these metering services with respect to regulatory year t, as determined by the AER. It will also include any applicable end-of-period adjustments in regulatory year t.

With the exception of the CPI and X factor, the percentage for each of the other factors above can be calculated by dividing the incremental revenues (as used in the total annual revenue formula) for each factor by the expected revenues for regulatory year t–1 (based on the prices in year t–1 multiplied by the forecast quantities for year t).

14.5.2 Application of the control mechanism formulae for alternative control services other than type 5 and 6 (inc. smart metering) services

This section sets out our final decision on the control mechanism formulae for price-capped alternative control services.

14.5.2.1 Fee-based services

Consistent with our final F&A, the price cap formula that will apply to the Victorian distributors' fee-based alternative control services (excluding revenue-capped type 5 and 6 (inc. smart metering) services) is set out in Figure 14.5.[96]

Figure 14.5 Price cap formula to apply to the Victorian distributors' fee-based alternative control services

$$\overline{p}_t^i \geq p_t^i \qquad \text{i=1,...,n and t=1, 2,…,5}$$

$$\overline{p}_t^i = \overline{p}_{t-1}^i \times (1 + \Delta CPI_t) \times (1 - X_t^i) + A_t^i$$

Where:

$\overline{p}_t^i$ is the cap on the price of service i in year t. For the first year of the regulatory control period, the cap on the price of service i will be as per the schedule of approved charges set out in Attachment 15.

96 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 70-71.

p_t^i is the price of service i in year t.

$\overline{p}_{t-1}^i$ is the cap on the price of service i in year t–1.

t is the regulatory year.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[97] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t^i is the X factor for service i in year t. The value of this factor is as specified in Attachment 15 – Alternative Control Services.

A_t^i is the sum of any adjustments for service i in year t. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year t, as determined by the AER.

14.5.2.2 Quoted services

Consistent with our final F&A, the price cap formula that will apply to the Victorian distributors' alternative control services provided on a quotation basis is set out in Figure 14.6 below.[98]

Quoted services – billing transparency

Our final decision is to introduce requirements around transparency of billing for quoted services. When charging for quoted services:

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97 If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

98 AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 70-71.

- The Victorian distributors must provide itemised invoices to the customer or the service recipient. The itemised invoices must show the major cost components. At a minimum, invoices must contain information on the cost components to demonstrate compliance with the control mechanism formula for quoted services (see Figure 14.6).
- The charges must be consistent with good industry practice in terms of the resource requirements.

We have made this decision following feedback we received throughout the New South Wales 2019–24 regulatory determinations, particularly from Accredited Service Providers, with regards to a lack of transparency around invoices received.[99] This will aid in achieving consistency between regulatory arrangements for similar services across all jurisdictions.[100]

Quoted services formula – margin component

Our final decision does not accept the inclusion of a margin component in the quoted services price cap formula. We do not consider a material change in circumstances has occurred since the F&A that allows us to consider a margin component in the quoted services price control formula.

In their initial proposals, AusNet Services[101] and Jemena[102] proposed a margin component be included in the cost build-up for quoted ancillary network services. However, we did not accept the inclusion of margin in our draft decision as we were not satisfied there had been a material change in circumstances since the F&A that would allow us to consider changing the quoted services formula.[103]

In response, AusNet Services accepted our draft decision to not include a margin component.[104] However, Jemena did not accept our draft decision.[105] Jemena reasoned that including a margin component is consistent with the AER's determinations for TasNetworks and SA Power Networks, and is supported in the consultancy report provided by Marsden Jacob for the TasNetworks draft decision.

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99 AER, *Ausgrid draft decision attachment 13 - Control mechanisms*, November 2018, pp. 17-18; AER, *Endeavour Energy draft decision attachment 13 - Control mechanisms*, November 2018, p. 15; AER, *Essential Energy draft decision attachment 13 - Control mechanisms*, November 2018, pp. 16-17.

100 NER, cl. 6.2.5(d)(4).

101 AusNet Services, *Regulatory Proposal 2021–26 Part IV*, January 2020, pp. 59-60.

102 Jemena, *Attachment 07-07 - Price control mechanisms*, January 2020, p. 11.

103 AER, *Draft decision - AusNet Services distribution determination 2021–26 - Attachment 14 - Control mechanisms* September 2020, pp. 33-34; AER, *Draft decision - CitiPower distribution determination 2021–26 - Attachment 14 - Control mechanisms,* September 2020, pp. 33-34; AER, *Draft decision - Jemena distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-34; AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-34; AER, *Draft decision - United Energy distribution determination 2021–26 - Attachment 14 - Control mechanisms*, September 2020, pp. 33-34.

104 AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, p. 174.

105 Jemena, *Attachment 07-01 - Price control mechanisms*, December 2020, pp. 9-10.

In support of its proposal, Jemena also stated that:

- the circumstances they face are identical to all other distributors, including NER requirements and timing obligations, decisions made, and materiality of the issue
- the substance of the issue should be considered rather than an administrative timing issue, and
- an explicit margin reflects the principle of competitive neutrality, assists in promoting development of competition, and assists in achieving consistency across all jurisdictions.

As set out in our TasNetworks and SA Power Networks distribution determinations, we considered a material change in circumstance allowed us to consider including a margin in the quoted services price cap formula after publication of the F&A.[106] We do not consider a material change in circumstance has been provided to us in regard to the Victorian distributors.

As raised by Jemena, we agree that consistency across distributors and jurisdictions is desirable where appropriate. However, we consider consistency itself is not a material change in circumstances, particularly considering that only two of the nine determinations we made in the last two years included a margin component.

We also agree that including an explicit margin may better promote a competitive environment. However, we have not been provided evidence that would suggest there has been a material change in the development of competition for these services that would warrant including a margin. As it stands, there is little competition for these services which has been the environment for these services for some time.

Jemena is correct, the Marsden Jacob labour rates we use as the upper bound of efficient labour input rates for quoted service prices includes a margin. We do not consider that aspect in itself is a material change in circumstances. In fact, we would need to consider whether to exclude the margin in the Marsden Jacob labour rates to avoid any double recovery of the margins.

As a result, we do not consider Jemena has provided sufficient reasoning that suggest that a material change in circumstances apply that would permit a departure from what is set in the F&A.

For this component to be considered in a future determination, we recommend the Victorian distributors raise the issue in the F&A process, supported by evidence of the potential for a competitive market that would warrant the inclusion of a margin. Additionally, any margin component would need to be removed from the benchmark labour rates that we use in our determination.

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106 AER, *TasNetworks draft decision attachment 13 - Control mechanisms*, September 2018, pp. 20-21; AER, *SA Power Network draft decision attachment 13 - Control mechanisms*, October 2019, p. 20.

Quoted services formula – tax component

Our final decision does not accept the inclusion of a tax component in the quoted services price cap formula. We do not consider a material change in circumstances has occurred since the F&A that allows us to consider a margin component in the quoted services price control formula.

In their initial proposals, the Victorian distributors proposed a tax component to be included in the cost build-up for quoted ancillary network services.[107] However, we did not accept the inclusion of tax in our draft decision as we were not satisfied there had been a material change in circumstances since the F&A that would allow us to consider changing the quoted services formula.

In its revised proposal, AusNet Services did not accept our draft decision to not include the tax component of the quoted services formula.[108] AusNet Services reasoned the tax component should be included to establish parity with standard control services, and to ensure consistency with the Marsden Jacob report used for our draft decision.

As stated in our draft decision and above, we have limited discretion to depart from the control mechanisms set out in the F&A paper.[109] We can only depart from the formulae if we consider there has been a material change in circumstance.

For our final decision, we do not consider AusNet Services have provided any further reasoning that supports a material change in circumstances having occurred.

In response to AusNet Services revised proposal, we note:

- There is no requirement for the basis of the control mechanism for alternative control services to be on parity with standard control services.[110]
- The Marsden Jacob report relates to the labour rates we use as the upper bound of efficient labour input rates for provision of alternative control services. Within this context, the Marsden Jacob report refers to tax only in relation to payroll tax, and the tax implicit in allowances for margins within the overhead rates. We therefore consider it implicit that the labour rates we approve already includes provision for this tax component of labour.

For this component to be considered in a future determination, we recommend the Victorian distributors raise the issue in the F&A process, supported by evidence as to the need to include a tax component.

[107] Jemena, *Attachment 07-07 - Price control mechanisms*, January 2020, pp. 9-11; AusNet Services, *Regulatory Proposal 2021–26 Part IV*, January 2020, pp. 59-60; CitiPower, *APP08 - Price control formula*, January 2020, p. 8; Powercor, *APP08 - Price control formula*, January 2020, p. 8; United Energy, *APP08 - Price control formula*, January 2020, p. 9.

[108] AusNet Services, *Revised Regulatory Proposal 2021–26*, December 2020, pp. 190-191.

[109] NER, cl. 6.12.3(c) and (c1).

[110] NER, cl. 6.2.6.

14.5.3 New services introduced during the regulatory control period

During the 2021–26 regulatory control period, we will allow the Victorian distributors to introduce new services in limited circumstances. Our assessment of new services will include consideration of the extent stakeholders have transparency over the costs of the service as well as the likely benefits to customers from the service.

We understand there are times where a distributor cannot foresee a specific new service at the time of the regulatory determination. This is especially relevant in public lighting where new technologies are emerging, including more advanced light-emitting diode (LED) lamps and the integration of smart devices in public lighting infrastructure.

We appreciate there may be benefits in introducing new services within a regulatory control period in limited circumstances, such as customers having access to more efficient or cheaper lighting. However, when a new service is being introduced customers should benefit from the protections offered by the regulatory framework where possible, such as the ability to assess the costs.

Where new services are to be introduced that clearly fall within one of the established service groupings, such as public lighting, a quoted price approach is to be adopted with the price to be based on a relevant service within that same service grouping.[111] For example, the price for a new type of public lighting would be based on a relevant public lighting service.

Prices for new services will be considered as a part of the annual pricing process.

- The Victorian distributors must advise us of any new alternative control services to be introduced within the regulatory control period
- Prior to submitting their annual pricing proposal, the Victorian distributors must submit to the AER:
    - a detailed description of the service along with how the new service will be charged, and
    - the proposed quoted price setting out each cost component consistent with Figure 14.6 below.

The AER will consider the proposal for inclusion in the relevant annual pricing proposal.

This is consistent with our F&A, and regulatory determinations across all NEM jurisdictions.

[111] AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 68-69.

Figure 14.6 Price cap formula to apply to the Victorian distributors' quoted alternative control services

$$Price = Labour + Contractor\ Services + Materials$$

Where:

$Labour$ consists of all labour costs directly incurred in the provision of the service, which may include labour on-costs, fleet on-costs and overheads. Labour is escalated annually by $(1 + \Delta CPI_t)(1 - X_t^i)$ where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[112] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2
>
> minus one.

For example, for 2021–22, year t–2 is the December quarter 2019 and year t–1 is the December quarter 2020.

X_t^i is the X- factor for service i in year t. The value of this factor is as specified in attachment 15 – alternative control services.

$Contractor\ Services$ reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

$Materials$ reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

[112] If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

A DUoS unders and overs account

To demonstrate compliance with the distribution determination applicable to it during the 2021–26 regulatory control period, each Victorian distributor must maintain a DUoS unders and overs account in its annual pricing proposal.

The Victorian distributors must provide the amounts for the following entries in their DUoS unders and overs accounts for the most recently completed regulatory year (t–2), the current regulatory year (t–1) and the next regulatory year (t):

1. An opening balance for year t–2, year t–1 and year t.
2. An interest charge for one year on the opening balance for each regulatory year (t–2, t–1 and t). These adjustments are to be calculated using the adjusted nominal WACC for each intervening year between regulatory year t–2 and year t. The WACC applied for each year will be the real vanilla WACC approved by the AER in the relevant annual update, escalated for actual inflation for the relevant year.[113]
3. The amount of revenue recovered from DUoS charges in respect of that year, less the total annual revenue for the year in question.
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the approved nominal WACC.
5. The total sum of items 1–4 to derive the closing balance for each year.

The Victorian distributors must provide details of calculations in the format set out in Table 14.1. In general:

- Amounts provided for the most recently completed regulatory year (t–2) must be audited.[114]
- Amounts provided for the current regulatory year (t–1) will be regarded as an estimate.
    - The estimated revenue amounts provided for the t-1 current regulatory year should be the best estimate of expected revenue for the year. The inclusion of the t-1 year in the unders and overs account is intended to smooth any impacts of the t-2 true-up before they occur, reducing price volatility resulting from this true-up mechanism.
    - Victorian distributors should provide supporting information as to how those estimates are calculated and why they should be considered the best estimate.
- Amounts for the next regulatory year (t) will be regarded as a forecast.

[113] If circumstances require, alternative adjustments for an appropriate cost of capital may be applied following consultation between the AER and relevant distributor(s).

[114] A reasonable assurance report sufficiently meets these auditing requirements. Where amounts provided match other audited submissions to the AER, further assurance is not required (e.g. RINs), and should be referenced.

- The Victorian distributors should provide supporting information as to how those forecasts are calculated and why they should be considered reasonable.

In exceptional circumstances, the jurisdictional scheme amounts unders and overs account can accommodate additional years—such as year t–3.[115] Such a case arises in accommodating the transition of calendar years to financial years. Accordingly, a three-period account will be maintained for the years 2021–22 and 2022–23. The section below sets out our expectations as to how these additional periods will be treated, and where audit requirements apply.

In 2021–22:

- t–3 will represent the actual (audited) results of the 2019 year
- t–2 will represent the estimated (unaudited) results of the 2020 year[116]
- t–1 will represent the estimated (unaudited) results of the 2021 regulatory control period
- t will represent the forecast results of the 2021–22 year.

In 2022–23:

- t–3 will represent the actual (audited) results of the 2020 year
- t–2 will represent the actual (audited) results of the 2021 regulatory control period
- t–1 will represent the estimated (unaudited) results of the 2021–22 year
- t will represent the forecast results of the 2022–23 year.

In proposing variations to the amount and structure of DUoS charges, the Victorian distributors are expected to achieve a closing balance as close to zero as practicable in their DUoS unders and overs accounts in each forecast year in their annual pricing proposals during the 2021–26 regulatory control period. The Victorian distributors are also expected to achieve a closing balance that is less than zero (i.e. a negative amount) to maintain compliance with the operation of the revenue cap. Where a positive closing balance is proposed, this will be considered as exceeding the revenue cap, and therefore not compliant.

As set out in section 14.4.1.5, our final decision is to allow CitiPower to smooth its recovery of under-recovered distribution revenues in 2020 due to significantly reduced electricity consumption caused by the COVID-19 pandemic. We have not made provision for smoothing of under or over recovered revenues for the other Victorian distributors as their distribution revenues in 2020 were not materially impacted.

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115 Any amounts provided for additional years prior to t-2 must be audited.

116 While the 2020 revenue is expected to be known in time for 2021–22 pricing, we have allowed an extra year for this true-up to allow for any issues that may arise in reporting 2020 revenues.

Table 14.1 Example calculation of DUoS unders and overs account ($'000, nominal)

	Year t–2 (actual)	Year t–1 (estimate)	Year t (forecast)
(A) Revenue from DUoS charges	**45 779**	**40 269**	**39 510**
(B) Less TAR for regulatory year =	**43 039**	**41 427**	**44 429**
+ Adjusted annual smoothed revenues (AAR_t)	40 089	41 283	44 263
+ Incentive scheme amounts (I_t) [a]	1 026	34	36
+ Cost pass through amounts (C_t)	1 824	0	0
+ Annual adjustments (B_t - under/over recovery adjustment)[b]	100	110	130
(C) Revenue deliberately under-recovered in year	**1 000**	**0**	**0**
(A minus B plus C) Under/over recovery of revenue for regulatory year	**3 740**	**–1 158**	**–4 919**[c]
DUoS unders and overs account			
Adjusted nominal WACC (per cent)	5.00%	5.50%	6.00%
Opening balance	1 737	5 656[d]	4 778
Interest on opening balance	87	311	287
Under/over recovery of revenue for regulatory year	3 740	–1 158	–4 919
COVID-19 adjustment	0	0	0
Interest on under/over recovery for regulatory year	92	–31	–145
Closing balance	**5 656**	**4 778**	**0**[e]

Notes: (a) Includes incentive schemes as set out in our determination, with the exception of those incentive schemes that are calculated and applied through our regulatory determination (e.g. CESS and EBSS).

(b) B_t parameter calculations in the DUoS unders and overs account exclude the true-up for DUoS revenue under/over recovery for the regulatory year and are therefore expected to equal the sum of the remaining annual adjustments under B_t, as set out in Section 14.4.5.

(c) Approved DUoS revenue under/over recovery for regulatory year t.

(d) Opening balance is the previous year's closing balance.

(e) The Victorian distributors are expected to achieve a closing balance as close to zero as practicable (and ≤0) in their DUoS unders and overs accounts in each forecast year in their annual pricing proposals for the 2021–26 regulatory control period.

B Type 5 and 6 (inc. smart metering) services unders and overs account

To demonstrate compliance with its applicable distribution determination during the 2021–26 regulatory control period, each Victorian distributor must maintain a type 5 and 6 (inc. smart metering) services unders and overs account in its annual pricing proposal.[117]

The Victorian distributors must provide the amounts for the following entries in their type 5 and 6 (inc. smart metering) services unders and overs account for the most recently completed regulatory year (t–2), the current regulatory year (t–1) and the next regulatory year (t):

1. An opening balance for year t–2, year t–1 and year t.
2. An interest charge for one year on the opening balance for each regulatory year (t–2, t–1 and t). These adjustments are to be calculated using the adjusted nominal WACC for each intervening year between regulatory year t–2 and year t. The WACC applied for each year will be the real vanilla WACC approved by the AER in the relevant annual update, escalated for actual inflation for the relevant year.[118]
3. The amount of revenue recovered from metering charges in respect of that year, less the total annual revenue for the year in question.
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the approved nominal WACC.
5. The total sum of items 1–4 to derive the closing balance for each year.

The Victorian distributors must provide details of calculations in the format set out in Table 14.2. In general:

- Amounts provided for the most recently completed regulatory year (t–2) must be audited.[119]
- Amounts provided for the current regulatory year (t–1) will be regarded as an estimate.
    - The estimated revenue amounts provided for the t-1 current regulatory year should be the best estimate of expected revenue for the year. The inclusion of the t-1 year in the unders and overs account is intended to smooth any impacts of the t-2 true-up before they occur, reducing price volatility resulting from this true-up mechanism.

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[117] NER, cl. 6.18.2(b)(7).

[118] If circumstances require, alternative adjustments for an appropriate cost of capital may be applied following consultation between the AER and relevant distributor(s).

[119] A reasonable assurance report sufficiently meets these auditing requirements. Where amounts provided match other audited submissions to the AER, further assurance is not required (e.g. RINs), and should be referenced.

    - Victorian distributors should provide supporting information as to how those estimates are calculated and why they should be considered the best estimate.
  - Amounts for the next regulatory year (t) will be regarded as a forecast.
    - Victorian distributors should provide supporting information as to how those forecasts are calculated and why they should be considered the reasonable.

In exceptional circumstances, the jurisdictional scheme amounts unders and overs account can accommodate additional years—such as year t–3.[120]

Such a case arises in accommodating the transition of calendar years to financial years. Accordingly, a three-period account will be maintained for the years 2021–22 and 2022–23. The section below sets out our expectations as to how these additional periods will be treated, and where audit requirements apply.

In 2021–22:

  - t–3 will represent the actual (audited) results of the 2019 year
  - t–2 will represent the estimated (unaudited) results of the 2020 year[121]
  - t–1 will represent the estimated (unaudited) results of the 2021 regulatory control period
  - t will represent the forecast results of the 2021–22 year.

In 2022–23:

  - t–3 will represent the actual (audited) results of the 2020 year
  - t–2 will represent the actual (audited) results of the 2021 regulatory control period
  - t–1 will represent the estimated (unaudited) results of the 2021–22 year
  - t will represent the forecast results of the 2022–23 year.

In proposing variations to the amount and structure of metering charges, the Victorian distributors are expected to achieve a closing balance as close to zero as practicable in their metering unders and overs account in each forecast year in their annual pricing proposals for the 2021–26 regulatory control period. The Victorian distributors are also expected to achieve a closing balance that is less than zero (i.e. a negative amount) to maintain compliance with the operation of the revenue cap. Where a positive closing balance is proposed, this will be considered as exceeding the revenue cap, and therefore not compliant.

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120 Any amounts provided for additional years prior to t-2 must be audited.

121 While the 2020 revenue is expected to be known in time for 2021–22 pricing, we have allowed an extra year for this true-up to allow for any issues that may arise in reporting 2020 revenues.

Table 14.2 Example calculation of type 5 and 6 (inc. smart metering) services unders and overs account ($'000, nominal)

	Year t–2 (actual)	Year t–1 (estimate)	Year t (forecast)
(A) Revenue from type 5 and 6 (inc. smart metering) charges	**45 779**	**40 269**	**39 510**
(B) Less TARM for regulatory year =	**43 039**	**41 427**	**44 429**
+ Adjusted annual smoothed revenue (AAR_t)	41 215	41 427	44 429
+ Cost pass through amount (C_t)	1 824	0	0
+ AMI-OIC (T_t)	0	0	0
+ Annual adjustments (B_t - under/over recovery adjustment)[b]	0	0	0
(C) Revenue deliberately under-recovered in year	**1 000**	**0**	**0**
(A minus B plus C) Under/over recovery of revenue for regulatory year	**3 740**	**–1 158**	**–4 919**[b]
Type 5 and 6 (inc. smart metering) services unders and overs account			
Adjusted nominal WACC (per cent)	5.00%	5.50%	6.00%
Opening balance	1 737	5 656[c]	4 778
Interest on opening balance	87	311	287
Under/over recovery of revenue for regulatory year	3 740	–1 158	–4 919
Interest on under/over recovery for regulatory year	92	–31	–145
Closing balance	**5 656**	**4 778**	**0**[d]

Notes: (a) B_t parameter calculations in the type 5 and 6 (inc. smart metering) services unders and overs account exclude the true-up for type 5 and 6 (inc. smart metering) services revenue under/over recovery for regulatory year and are therefore expected to be 0.

(b) Approved type 5 and 6 (inc. smart metering) services revenue under/over recovery for regulatory year t.

(c) Opening balance is the previous year's closing balance.

(d) The Victorian distributors are expected to achieve a closing balance as close to zero as practicable (and ≤0) in their type 5 and 6 (inc. smart metering) services unders and overs accounts in each forecast year in their annual pricing proposals for the 2021–26 regulatory control period.

C Designated pricing proposal charges[122] unders and overs account

To demonstrate compliance with the distribution determination applicable to it during the 2021–26 regulatory control period, each Victorian distributor must maintain a designated pricing proposal charges unders and overs account in its annual pricing proposal.[123]

The Victorian distributors must provide the amounts for the following entries in their designated pricing proposal charges unders and overs accounts for the most recently completed regulatory year (t–2), the current regulatory year (t–1) and the next regulatory year (t):

1. An opening balance for year t–2, year t–1 and year t.
2. An interest charge for one year on the opening balance for each regulatory year (t–2, t–1 and t). These adjustments are to be calculated using the adjusted nominal WACC for each intervening year between regulatory year t–2 and year t. The WACC applied for each year will be the real vanilla WACC approved by the AER in the relevant annual update, escalated for actual inflation for the relevant year.[124]
3. The amount of revenue recovered from designated pricing proposal charges in respect of that year, less the total annual revenue for the year in question.
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the approved nominal WACC.
5. The total sum of items 1–4 to derive the closing balance for each year.

The Victorian distributors must provide details of calculations in the format set out in Table 14.3. In general, amounts provided for the most recently completed regulatory year (t–2) must be audited while amounts provided for the current regulatory year (t–1) will be regarded as an estimate.[125] Amounts for the next regulatory year (t) will be regarded as a forecast.

In exceptional circumstances, the jurisdictional scheme amounts unders and overs account can accommodate additional years—such as year t–3.[126]

122 Designated pricing proposal charges are charges related to: designated pricing proposal services (prescribed exit fees, prescribed common transmission services and prescribed transmission use of system services); avoided customer transmission use of system charges; charges provided by another distributor (but only to the extent they comprise of designated pricing proposal services or standard control services); and charges or payments related specified in NER clause 11.39.

123 NER, cll. 6.18.2(b)(6), 6.12.1(19), 6.18.7.

124 If circumstances require, alternative adjustments for an appropriate cost of capital may be applied following consultation between the AER and relevant distributor(s).

125 A reasonable assurance report sufficiently meets these auditing requirements. Where amounts provided match other audited submissions to the AER, further assurance is not required (e.g. RINs), and should be referenced.

126 Any amounts provided for additional years prior to t-2 must be audited.

Such a case arises in accommodating the transition of calendar years to financial years. Accordingly, a three-period account will be maintained for the years 2021–22 and 2022–23. The section below sets out our expectations as to how these additional periods will be treated, and where audit requirements apply.

In 2021–22:

- t–3 will represent the actual (audited) results of the 2019 year
- t–2 will represent the estimated (unaudited) results of the 2020 year[127]
- t–1 will represent the estimated (unaudited) results of the 2021 regulatory control period
- t will represent the forecast results of the 2021–22 year.

In 2022–23:

- t–3 will represent the actual (audited) results of the 2020 year
- t–2 will represent the actual (audited) results of the 2021 regulatory control period
- t–1 will represent the estimated (unaudited) results of the 2021–22 year
- t will represent the forecast results of the 2022–23 year.

In proposing variations to the amount and structure of designated pricing proposal charges, the Victorian distributors are required to achieve a closing balance that is less than zero (i.e. a negative amount) to maintain strict compliance with the NER.[128] Where a positive closing balance is proposed, this will be considered as exceeding the estimated amount of designated pricing proposal charges, and therefore not compliant.

The Victorian distributors are also expected to achieve a closing balance as close to zero as practicable in their designated pricing proposal charges unders and overs account in each forecast year in their annual pricing proposals during the 2021–26 regulatory control period.

127 While the 2020 revenue is expected to be known in time for 2021–22 pricing, we have allowed an extra year for this true-up to allow for any issues that may arise in reporting 2020 revenues.

128 NER, cl. 6.18.7(b).

Table 14.3 Example calculation of designated pricing proposal charges unders and overs account ($'000, nominal)

	Year t–2 (actual)	Year t–1 (estimate)	Year t (forecast)
(A) Revenue from designated pricing proposal charges (DPPC)	**40 077**	**34 944**	**36 609**
(B) Less DPPC related payments for regulatory year =	**34 365**	**38 734**	**39 200**
+ DPPC to be paid to TNSP	33 672	37 933	38 000
+ Avoided TUoS/DPPC payments	572	734	800
+ Inter-distributor payments	121	67	400
(A minus B) Under/over recovery of revenue for regulatory year	**5 712**	**–3 790**	**–2 540**[a]
DPPC unders and overs account			
Adjusted nominal WACC (per cent)	5.00%	5.50%	6.00%
Opening balance	167	6 028[b]	2 467
Interest on opening balance	8	332	148
Under/over recovery of revenue for regulatory year	5 712	–3 790	–2 540[a]
Interest on under/over recovery for regulatory year	141	–103	–75
Closing balance	**6 028**	**2 467**	**0**[c]

Notes: (a) Approved DPPC revenue under/over recovery for regulatory year t.

(b) Opening balance is the previous year's closing balance.

(c) In addition to complying with clause 6.18.7(b) of the NER (e.g. closing balance ≤0), the Victorian distributors are expected to achieve a closing balance as close to zero as practicable in their DPPC unders and overs accounts in each forecast year in their annual pricing proposals for the 2021–26 regulatory control period.

D Jurisdictional scheme amounts[129] unders and overs account

This Appendix applies to the following jurisdictional schemes for Victorian distribution businesses:

- ESV levy scheme[130]
- Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009.[131]

To demonstrate compliance with the distribution determination applicable to it during the 2021–26 regulatory control period, each Victorian distributor must maintain a jurisdictional scheme amounts unders and overs account in its annual pricing proposal.[132]

The recovery of jurisdictional scheme amounts for each of these schemes is to be reported through the unders and overs account as separate line items, as demonstrated in Table 14.4.

The Victorian distributors must provide the amounts for the following entries in their jurisdictional scheme amounts unders and overs accounts for the most recently completed regulatory year (t–2), the current regulatory year (t–1) and the next regulatory year (t):

1. An opening balance for year t–2, year t–1 and year t.
2. An interest charge for one year on the opening balance for each regulatory year (t–2, t–1 and t). These adjustments are to be calculated using the adjusted nominal WACC for each intervening year between regulatory year t–2 and year t. The WACC applied for each year will be the real vanilla WACC approved by the AER in the relevant annual update, escalated for actual inflation for the relevant year.[133]
3. The amount of revenue recovered from jurisdictional scheme amounts charges in respect of that year, less the total annual revenue for the year in question;
4. An adjustment to the net amount in item 3 by six months of interest. These adjustments are to be calculated using the approved nominal WACC.
5. The total sum of items 1–4 to derive the closing balance for each year.

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129 Jurisdictional scheme amounts are amounts a distributor is required under a jurisdictional scheme obligation as defined by the NER to: pay a person; pay into a fund established under an Act of a participating jurisdiction; credit against charges payable by a person; or reimburse a person, less any amounts recovered by the distributor from any person in respect of those amounts other than under the NER.

130 AER, *Determination - Request for the ESV Levy Scheme to be determined a jurisdictional scheme*, March 2021.

131 NER, cl. 6.18.7A(e)(1)(iv).

132 NER, cll. 6.12.1(20), 6.18.2(b)(6A), 6.18.7A(b) and (c).

133 If circumstances require, alternative adjustments for an appropriate cost of capital may be applied following consultation between the AER and relevant distributor(s).

The Victorian distributors must provide details of calculations in the format set out in Table 14.4. In general, amounts provided for the most recently completed regulatory year (t–2) must be audited while amounts provided for the current regulatory year (t–1) will be regarded as an estimate.[134] Amounts for the next regulatory year (t) will be regarded as a forecast. Table 14.4 demonstrates how ESV levies are to be incorporated, being considered a jurisdictional scheme by the AER.

In exceptional circumstances, the jurisdictional scheme amounts unders and overs account can accommodate additional years—such as year t–3.[135]

Such a case arises in accommodating the transition of calendar years to financial years. Accordingly, a three-period account will be maintained for the years 2021–22 and 2022–23. The section below sets out our expectations as to how these additional periods will be treated, and where audit requirements apply.

In 2021–22:

- t–3 will represent the actual (audited) results of the 2019 year
- t–2 will represent the estimated (unaudited) results of the 2020 year[136]
- t–1 will represent the estimated (unaudited) results of the 2021 regulatory control period
- t will represent the forecast results of the 2021–22 year.

In 2022–23:

- t–3 will represent the actual (audited) results of the 2020 year
- t–2 will represent the actual (audited) results of the 2021 regulatory control period
- t–1 will represent the estimated (unaudited) results of the 2021–22 year
- t will represent the forecast results of the 2022–23 year.

Where a Victorian distributor receives a government subsidy for jurisdictional schemes in lieu of recovering these amounts directly from jurisdictional scheme charges (or part thereof), it will be required to record the subsidy amount received as revenue. This will not impact the operation of the unders/overs account. Where a Victorian distributor receives a full government subsidy for jurisdictional schemes it will not recover any amounts from customers in relation to those jurisdictional schemes.

In proposing variations to the amount and structure of jurisdictional scheme charges, the Victorian distributors are required to achieve a closing balance that is less than

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134 A reasonable assurance report sufficiently meets these auditing requirements. Where amounts provided match other audited submissions to the AER, further assurance is not required (e.g. RINs), and should be referenced.

135 Any amounts provided for additional years prior to t-2 must be audited.

136 While the 2020 revenue is expected to be known in time for 2021–22 pricing, we have allowed an extra year for this true-up to allow for any issues that may arise in reporting 2020 revenues.

zero (i.e. a negative amount) to maintain strict compliance with the NER.[137] Where a positive closing balance is proposed, this will be considered as exceeding the estimated amount of jurisdictional scheme amounts, and therefore not compliant.

The Victorian distributors are also expected to achieve a closing balance as close to zero as practicable in their jurisdictional scheme amounts unders and overs account in each forecast year in their annual pricing proposal during the 2021–26 regulatory control period.

Table 14.4 Example calculation of jurisdictional scheme amounts unders and overs account ($'000, nominal)

	Year t–2 (actual)	Year t–1 (estimate)	Year t (forecast)
(A) Revenue from jurisdictional schemes	**19 777**	**23 121**	**26 965**
(B) Less jurisdictional scheme payments for regulatory year =	**20 272**	**20 959**	**28 641**
+ Jurisdictional scheme 1 payments	14 159	13 954	13 961
+ Jurisdictional scheme 2 payments	6 113	7 005	14 680
(A minus B) Under/over recovery of revenue for regulatory year	**–495**	**2162**	**–1 676**[a]
Jurisdictional scheme amount unders and overs account			
Adjusted nominal WACC (per cent)	5.00%	5.50%	6.00%
Opening balance	–52	–562[b]	1 628
Interest on opening balance	–3	–31	98
Under/over recovery of revenue for regulatory year	–495	2 162	–1 676[a]
Interest on under/over recovery for regulatory year	–12	59	–50
Closing balance	**–562**	**1 628**	**0**[c]

Notes: (a) Approved jurisdictional scheme amounts revenue under/over recovery for regulatory year t.

(b) Opening balance is the previous year's closing balance.

(c) In addition to complying with clause 6.18.7A(b) of the NER (e.g. closing balance ≤0), the Victorian distributors are expected to achieve a closing balance as close to zero as practicable in their jurisdictional scheme amount unders and overs accounts in each forecast year in their annual pricing proposals for the 2021–26 regulatory control period.

137 NER, cl. 6.18.7A(b).

E Annual pricing proposals

In line with our approach to annual pricing proposals for the Victorian distributors in previous regulatory periods, the AER will provide a Tariff Approval Model (TAM) for the Victorian distributors to use in submitting pricing proposals.

At least two weeks prior to annual pricing submissions being due we will provide the business with a pre-filled TAM to be used in the pricing proposal. This pre-filled TAM will include annual adjustments, revenue and cost true-up amounts from regulatory information notices or other sources, CPI and annual return on debt updates, and other components known by the AER. Pre-filling this data allows for the AER to verify inputs prior to the short timelines allowed within the pricing approval process.

The TAM to be used for the 2021–26 regulatory control period will include the escalation of price caps for ancillary network services and metering exit fees. This will ensure that price caps are escalated in the appropriate manner using the approved price cap formulae. It will also provide simplicity and consistency for AER review processes, as well as for stakeholders. The prices for public lighting services will be calculated through the AER Victorian public lighting model, updated each year for actual inflation.

The Victorian distributors will be required to input quantities and prices, and estimates required for unders/overs accounts, as well as any other inputs indicated by the AER in the TAM. The Victorian distributors will also provide information on indicative prices for future years. Where the Victorian distributors disagree with an input provided by the AER, or change any element of the TAM in their proposal, we require the business to indicate this in its pricing proposal, and provide supporting reasoning for the change.

In their pricing proposals, the Victorian distributors should also:

- provide a confidentiality template
- provide public versions of any confidential models for publication
- use version numbers in filenames for easy identification of revision by stakeholders (in the format of v1, v2, v3, etc.)
- provide details on methodologies for any forecasts provided (e.g. consumption forecasts)
- supporting information for any TSS requirements (e.g. standalone vs avoidable cost models or calculations).

F Rounding of inputs in annual pricing proposals

The following sets out our final determination around how Victorian distributors are required to use calculation inputs (e.g. whether on a rounded or unrounded basis) in the pricing approval process to demonstrate compliance.

Unrounded inputs to be used in calculations

'Unrounded', for this purpose, will be taken to mean at least fifteen digit floating point precision (the level of accuracy at which numbers will be stored in Microsoft Excel workbooks of .XLS, .XLSX, .XLSM or .XLSB). This definition accepts that numbers with fewer than fifteen floating digits may not require fifteen digits to express (such as 2.25 being equivalent to 2.25000000000000) but will meet the definition of fifteen digit floating point precision.

Unrounded values should be maintained throughout calculations. Where a calculation produces an output which is to be used as an input in another calculation, rounding should not occur. Rounding should be applied to final outputs only, unless otherwise specified.

Unrounded inputs should be taken from approved Excel models where appropriate. X factors should be unrounded inputs taken from the approved model. Where appropriate, inputs should be calculated as an alternative to using a rounded value.

For example, inflation should be calculated based around the CPI tables as provided by the ABS, or the AER's nominated best available substitute should this index cease to be calculated. The result of this calculation should be taken as is, not rounded before use. Table 14.5 sets out the required level of precision for an inflation calculation.

Table 14.5 Demonstration of inflation calculation

	Required Precision
The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2 (example)	112.1
The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1 (example)	114.6
ΔCPI_t	2.23015165031222%

Unrounded inputs include all those not specified below as suitable to be rounded in a given situation.

Instances where rounding is acceptable

In general, rounding in calculations must be done on a 'nearest' basis. So rounding to two decimal places means rounding to the nearest two decimal places, not rounding up automatically or down automatically. This accepts the convention that if a number falls precisely between two points, it can be rounded up (e.g. 2.245 can be rounded to 2.25 rather than 2.24). An exception to this for prices charged by the distributor is noted below, as these must be less than or equal to the price cap.

Price cap control mechanism formulae

When applying a price cap, the value of $\overline{p}_t^i$ should be rounded to the nearest two decimal places each year. When calculating the value of the price cap for the following period, the rounded value of the previous year's price cap must be used in the control mechanism formula to determine the value of the new price cap to ensure consistency in the price cap from year-to-year.

Table 14.6 Demonstration of price cap calculation (with rounding)

	Required Precision
$\overline{p}_{t-1}^i$	$23.28
X factor (example: should be taken from model)	-7.12546236955321%
ΔCPI_t	2.23015165031222%
$\overline{p}_t^i$ (unrounded)	$25.4938708296164
$\overline{p}_t^i$ (rounded)	$25.49

Prices p_t^i charged by the distributor can be rounded to as few or as many decimal places as required, subject to being less than or equal the two decimal place value of $\overline{p}_t^i$. In the above table, this would mean a price of $25.49 would be acceptable, as would a price of $25.4899. However, a price of $25.493 would not be compliant.

For the avoidance of ambiguity, where a price is expressible as a rate for a period of time, rounding of the price cap will apply to the largest relevant time period. So the price of an hourly service will be capped on an hourly basis. However, a service which can be priced either on a daily rate or an annual rate will have rounding apply to the cap on the annual rate. The daily rate should then represent the annual rate divided by 365, or 366 if the regulatory year to which the price applies includes 29 February 2024. This resulting daily rate may be expressed on a rounded basis (with discretion on the appropriate level of decimal places to apply) but must be based on a rounding to the nearest decimal place.

Revenue cap control mechanism formulae

The following variables used in the revenue cap formula should be rounded to no fewer than two decimal places: adjusted annual smoothed revenue requirement, sum of incentive scheme adjustments, sum of annual adjustment factors and sum of approved cost pass through amounts.

However, prices, quantities, X factors, CPI and adjustments inputs (incentive scheme performance adjustments, approved cost pass through adjustments, etc.) must be used unrounded in the revenue cap formula.

Shortened forms

Shortened form	Extended form
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CESS	capital expenditure sharing scheme
CPI	consumer price index
CSIS	customer service incentive schemes
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DPPC	designated pricing proposal charges
DUoS	distribution use of system
ESCV	Essential Services Commission Victoria
ESV	Energy Safe Victoria
EBSS	efficiency benefit sharing scheme
F&A	framework and approach
MRP	market risk premium
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	network service provider
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RIN	regulatory information notice

Shortened form	Extended form
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
TAM	Tariff Approval Model
TAR	total allowable revenue
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 15 Pass through events

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

15 Pass through events

The pass through mechanism of the National Electricity Rules (NER) recognises that a distributor can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass through enables a distributor to recover (or pass through) the costs of defined yet unpredictable, high cost events that are not built into our distribution determination. The NER include the following prescribed pass through events for all distributors:

- a regulatory change event
- a service standard event
- a tax change event
- a retailer insolvency event.

In addition to these prescribed events, other pass through events may be 'nominated' by a service provider for a regulatory control period.

This attachment sets out our final decision on the nominated pass through events that will apply to AusNet Services for the 2021–26 regulatory control period.

15.1 Final decision

Our final decision is that the following nominated pass through events will apply to AusNet Services for the 2021–26 regulatory control period:

- insurance coverage event
- insurer credit risk event
- natural disaster event
- terrorism event
- retailer insolvency event.

These events are defined in Table 15.2. The reasons for our decisions are set out in section 15.5. We have also accepted some of the minor proposed amendments to the insurance coverage event and made minor amendments to the definitions for the natural disaster and terrorism events. Our reasons for these decisions are set out in sections 15.5.1 and 15.5.2.

Our final decision is to not accept the proposed insurance premium event, environment protection event and major cyber event. Our reasons for these decisions are set out in sections 15.5.3, 15.5.4 and 15.5.5.

15.2 AusNet Services' revised proposal

In our draft decision we did not accept all the nominated pass through events proposed by AusNet Services.[1] Instead we substituted our own event definitions of natural disaster, retailer insolvency and insurance coverage to provide consistency between AusNet Services and other service providers.[2] Additionally, we did not accept AusNet Services' proposed insurance premium and electrical vehicle uptake nominated events.[3]

In its revised proposal, AusNet Services accepted our draft decision in relation to the following pass through events:[4]

- insurer credit risk event;
- natural disaster event;
- terrorism event; and
- retailer insolvency event.

It welcomed our draft decision to accept the insurance coverage event suggesting minor amendments to the definition and accepted our decision not to accept the electric vehicle uptake nominated event.[5]

AusNet Services did not accept our draft decision with respect to the insurance premium event. It provided additional information to demonstrate that a cost pass through mechanism is the appropriate regulatory mechanism to recover the cost of materially higher insurance premiums, and stated that this event meets the nominated pass through event considerations. AusNet Services also proposed minor amendments to its original definition of the insurance premium event to align with the drafting proposed by the other Victorian distributors.[6]

AusNet Services also proposed two new pass through events:[7]

- an environment protection pass through event associated with amendments to the *Environment Protection Act (EPA) 2017* (Vic). This is intended to ensure access to the pass through framework if AusNet Services was to incur costs in future to comply with the amended environment protection legislation and associated subordinate instruments.
- a major cyber cost pass through event. This event is intended to address any material risk associated with a cyber-attack that it considered is not available under

[1] AER, *Draft Decision, AusNet Services determination, Attachment 15*, September 2020, p. 4.
[2] AER, *Draft Decision, AusNet Services determination, Attachment 15*, September 2020, pp. 4, 12-15.
[3] AER, *Draft Decision, AusNet Services determination, Attachment 15*, September 2020, pp. 15-17.
[4] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p. 153.
[5] AusNet Services,*Revised regulatory proposal 2022–26,* December 2020, p. 153.
[6] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 156–159.
[7] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 153, 162–166.

the existing cost recovery frameworks for the totality of the costs incurred as a result of such an attack.

15.2.1 Stakeholder submissions

We received four submissions on the revised proposals of the Victorian distributors which raised issues about the proposed nominated pass through events that are relevant to AusNet Services.[8] At a high level, submissions did not support the environment protection and major-cyber nominated events. We have taken these submissions, and any other concerns consumers identified, into account in developing the positions set out in this final decision. A summary of the nominated cost pass through issues raised in submissions is provided in Table 15.1.

Table 15.1 Stakeholder submissions

Stakeholder	Issue	High Level summary and reference
AER Consumer Challenge Panel, sub-panel 17 (CCP17), Victorian Community Organisations (VCO), Energy Consumers Australia (ECA), Energy Users Association of Australia (EUAA)	Pass-throughs	The CCP17 did not consider that any provision is needed for changes in EPA costs in the Final Determination, unless the Victorian Parliament legislates before the determination is finalised. It also considered environmental pass-through events are unnecessary. The CCP17 also noted the increased use of pass throughs as a response to uncertainty from COVID. The CCP17 queried this approach and suggested it only occur where established rules and processes are inadequate.[9] The VCO did not support the inclusion of EPA regulation as a pass through, and expressed tentative support of the insurance coverage event but noted detailed examination of the approach would be required. There was also support for a “bushfire insurance event” but that it should not include more general insurance. The VCO also did not support the major cyber event pass through. [10] EUAA[11] and ECA's consultant Spencer and Co[12] did not support a nominated major cyber cost pass through event. The VCO supported analysis of the insurance premium proposals to ensure that the step change and cost pass through events are not double counted. It noted there is support for developing the most efficient bushfire insurance program for each business, with consumers sharing in the increased costs and risks, including general insurance, which it considered had not been impacted by the increased bushfire risk.[13]

8 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 69; VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 28-29, 56, 64-66 (Headberry Partners P/L); EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p.11; Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp.15, 19.

9 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 69.

10 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 28-29, 64–66.

11 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p.11.

12 Spencer&Co report to ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 19.

13 Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 56.

Stakeholder	Issue	High Level summary and reference
		Consultants for ECA, Spencer&Co supported the steps taken by businesses to mitigate the costs impacts of rising insurance premiums on customers. They considered the pass through of payments up to the deductible in the case that an event occurs is a reasonable sharing of risk between networks and customers. They also suggest that the AER should consider a review of insurance offerings to determine if market offerings properly reflect the risk of these events.[14]

Source: AER analysis

15.3 Assessment approach

The NER sets out how we must assess nominated pass through events, and how we must assess an application from a service provider to pass through changes in costs where an event occurs.[15]

Our assessment approach is guided by the National Electricity Objective (NEO) and the Revenue and Pricing Principles.[16] One of the Revenue Pricing Principles is that the service provider should have a reasonable opportunity to recover at least the efficient costs of providing services and complying with regulatory obligations.[17] The NEO and the Revenue Pricing Principles also reflect the importance of incentives to promote economic efficiency,[18] and balance the risks of under and over investment.[19]

In the context of pass through events, we have particular regard to the impact on price, quality, reliability and security of supply that may arise as a result of any change in the efficient operation of, and ability and incentive of, a service provider to invest in its network. This is a similar approach to that taken by the Australian Energy Market Commission (AEMC) when considering pass through event rule changes.[20]

In determining whether we accept a nominated pass through event, we must take into account the 'nominated pass through event considerations' as defined, which are as follows:[21]

- 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);

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14 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 15 (Spencer&Co).

15 NER, cll. 6.5.10(b), 6.6.1.

16 NEL, ss. 7 and 7A.

17 NEL, s. 7A(2).

18 NEL, s. 7A(3).

19 NEL, s. 7A(6).

20 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 6.

21 NER, Chapter 10, definition of nominated pass through event considerations.

- whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;
- 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;
- whether the relevant service provider could insure against the event, having regard to:
    - the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or
    - whether the event can be self-insured on the basis that:
        - it is possible to calculate the self-insurance premium; and
        - 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
- any other matter the AER considers relevant and which the AER has notified network service providers is a nominated pass through event consideration.

The AEMC described the purpose of the nominated pass through event considerations as:

> to incorporate and reflect the essential components of a cost pass through regime in the NER. It was intended that in order for appropriate incentives to be maintained, any nominated pass through event should only be accepted when event avoidance, mitigation, commercial insurance and self-insurance are unavailable.[22]
>
> that a pass through event should only be accepted when it is the least inefficient option and event avoidance, mitigation, commercial insurance and self-insurance are found to be inappropriate. That is, it is included after ascertaining the most efficient allocation of risks between a service provider and end customers.[23]

This protects the incentive regime under the NER by limiting erosion of a service provider's incentives to use market based mechanisms to mitigate the cost impacts that would arise.[24] This promotes the efficient investment in, and efficient operation and use of, network services for the long term interests of consumers with respect to price.[25]

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22 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 19.

23 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 20.

24 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 8.

25 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 8.

As a matter of good regulatory practice, we also take into account the desirability of consistency in our approach to assessing nominated pass through events across our electricity determinations and gas access arrangements.[26]

15.4 Interrelationships

As discussed in our draft decision, the pass through mechanism is not the only way service providers can manage their risks under a distribution or transmission determination. It is interrelated with other parts of this determination, in particular with AusNet Services' forecast operating expenditure (opex), capital expenditure and the rate of return included in our revenue determination. We must specify and take account of these interrelationships.[27] This requires us to balance the incentives in the various parts of our decision.

15.5 Reasons for final decision

15.5.1 Insurance coverage event

Our final decision is to include the insurance coverage event. The only change from the draft decision definition is we have accepted one of the amendments proposed by AusNet Services.

AusNet Services proposed a number of definitional amendments to the insurance coverage event,[28] which are essentially the same as what the other Victorian distributors have also proposed. We understand the amendments proposed by the Victorian electricity distributors intended to clarify the operation of the insurance coverage event.

When we replaced the insurance cap event with the insurance coverage event[29], we inserted three key changes to the definition:

- "changed circumstances" means movements in the relevant insurance liability market that are beyond the control of the network business, where those movements mean that it is no longer possible for the network business to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in the definition within the scope of that insurance policy or set of insurance policies
- "costs" means the costs that would have been recovered under the insurance policy or set of insurance policies had:

26 AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 18.

27 NEL, s. 16(1)(c).

28 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 154–155.

29 AER, *Final Decision, SA Power Networks Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 13–14; AER, *Final Decision, Ergon Energy Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 9–10; AER, *Final Decision, Energex Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 9–10.

- the limit not been exhausted; or
- those costs not been unrecoverable due to changed circumstances.

- "a relevant insurance policy or set of insurance policies" means an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which a network business was regulated.

These key changes recognised the possibility of future coverage gaps (negative impacts on deductible schedules or reinstatement rights due to movements in the insurance liability market that are beyond the control of the network business) and that network businesses often have multiple insurance policies. At the same time, we sought to preserve appropriate pass through event incentives under a normal operating environment.

We have also applied the draft decision insurance coverage definition to other service providers[30] and we consider it would be preferable to maintain a consistent definition across network businesses rather than update the definition with the following proposed minor amendments:[31]

- clarifying that unrecoverable costs may include such costs "whether wholly or in part"
- clarifying that costs may be incurred "either separately or in aggregate"
- providing the definition for the base year
- clarifying that "changed circumstances" includes movements in the relevant insurance liability market "since the acquisition of the insurance policy or set of insurance policies that applied during the majority of the base year".

A further amendment proposed by AusNet Services is that "changed circumstances" should mean movements in the relevant insurance liability market that result in it no longer being possible for AusNet Services to take out a relevant insurance policy with a "reputable insurer".[32] We consider that the decision for AusNet Services to seek appropriate insurance cover on reasonable commercial terms is solely in the domain of the business, and we expect that AusNet Services will safeguard that business decision. We do not consider it necessary to prescribe the insurers who AusNet Services may seek coverage from.

We accept the proposed amendment to include "any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs" as a matter that the AER will have regard to in assessing an

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30 AER, *Final Decision, SA Power Networks Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 13–14; AER, *Final Decision, Ergon Energy Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 9–10; AER, *Final Decision, Energex Distribution Determination 2020–25, Attachment 14 Pass through events*, June 2020, pp. 9–10.

31 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 154–155.

32 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 154–155.

insurance coverage pass through event application.[33] This aligns with our work to release a final guidance note on the insurance coverage pass through event following further consultation with stakeholders in July 2021.[34]

15.5.2 Insurer credit risk, natural disaster, terrorism and retailer insolvency event

AusNet Services accepted our draft decision on insurer credit risk, natural disaster, terrorism and retailer insolvency events.[35] As a result, we have included these events in our final decision. However, we have made minor amendments to the definitions of natural disaster and terrorism events to reflect the symmetry between positive and negative cost pass through events reflected in the NER and add clarity.[36] Specifically, in these two event definitions we have replaced "increases the costs" with "changes the costs". We also adopted an additional explicit reference to "cyclone" and "earthquake" in the definition of natural disaster event as proposed by Jemena.[37] The amended definitions are set out in Table 15.2.

15.5.3 Insurance premium event

AusNet Services' re-proposed an insurance premium cost pass through event in its revised proposal, stating that the insurance coverage event cost pass through does not allow a business to recover material increases in its insurance premiums.[38] AusNet Services' re-proposal of an insurance premium event is intended to address potentially higher premium costs in the next regulatory control period. These would be additional to the higher costs AusNet Services proposed as an insurance premium step change in its revised opex proposal. The proposed step change costs reflect premium increases known as a result of its 2020 insurance renewal. The insurance premium cost pass through event would be for any additional increases. [39]

For reasons outlined below, we consider on balance that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period. As a result, our final decision is to not accept an insurance premium cost pass through event, but rather to include forecast insurance premium costs as a part of AusNet Services' opex for the 2021–26 regulatory control period.

As set out above, under the NER, a business may propose a nominated pass through event in its revenue proposal. The AER must then assess any such proposals and take

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33 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 154–155.

34 See AER, *Draft Guidance Note –Guidance Note on insurance coverage pass through event*, February 2021, p. 4.

35 AusNet Services, *Revised regulatory proposal 2022–26,* December 2020, p. 153.

36 NER, cll. 6.6.1 (a)-(b).

37 Jemena, *Revised regulatory proposal 2022–26 - Att 08-01,* December 2020, p. 5.

38 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 156–159.

39 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 156–159.

into account the NER considerations for a nominated cost pass through event.[40] In assessing AusNet Services' proposal, we have had regard to each of the nominated pass through event considerations.

Generally, we consider that cost pass through events should be the last option available for network businesses to recover costs in order to protect the incentive mechanisms of our framework.[41] As set out above in our assessment approach, the NER cost pass through framework is intended to ensure pass through events should only be accepted when it is the least inefficient option and event avoidance, mitigation and insurance are found to be inappropriate.[42]

In this regard, our view on balance is that in the current circumstances while there is some uncertainty associated with forecasting insurance premium increases, under our incentive based framework, businesses are best incentivised to achieve efficient cost outcomes by including these in the total opex forecast for the 2021–26 regulatory control period.

As set out in Attachment 6, section 6.4.3.4, the forecasts available to us take into account additional information that AusNet Services provided from its insurance brokers (AON) about future premium increases, as well as our consultant's (Taylor Fry) review of these forecasts.[43] We consider that including future premium increases in the opex forecast for the 2021–26 regulatory control period incentivises AusNet Services to continue to do all it can to try to manage and mitigate future increases in insurance premium increases, including by managing risks associated with insurance liability, especially for bushfires. This is consistent with our ex-ante incentive-based regulatory framework. Any measure to diminish this incentive, such as the use of a cost pass through, would work counter to this regime.

We acknowledge there are benefits of using a cost pass through for businesses to recover insurance premium costs over the next regulatory control period, including as raised in some submissions. These include that a cost pass through lessens the need to set a forecast when there is significant uncertainty and customers only pay for higher costs when they are known during the period. However, we consider on balance that the long term interests of consumers is better served if the appropriate incentives remain with the businesses to actively work to moderate expected increases in insurance premiums over the next regulatory control period.

For the reasons set out above, we have not accepted AusNet Services' proposed insurance premium event nominated cost pass through for the 2021–26 regulatory control period.

[40] NER, cl. 6.5.10 (b).

[41] AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. i.

[42] AEMC, *Cost pass through arrangements for Network Service Providers, Rule Determination*, 2 August 2012, p. 20.

[43] Taylor Fry, *AER AusNet Services Bushfire Insurance Public summary*, March 2021.

The above discussion and decision on the insurance premiums pass through event should be read in conjunction with our final decision on the insurance premiums step change in Attachment 6 of this final decision, section 6.4.3.4.

15.5.4 Major Cyber event

Our final decision is not include the major cyber event proposed by AusNet Services.

AusNet Services' revised proposal included a new pass through event for major cyber events based on its view that cyber events may fall outside the terrorism event definition and/or the inability to determine motivation of the perpetrators of a major cyber-attack.[44]

In their submissions, the EUAA and ECA's consultant Spencer and Co did not support a major cyber event being a nominated cost pass through given it covers costs associated with a non-terrorism event.[45]

We accept that the occurrence of major cyber events, as defined, cannot be completely ruled out. One of the key factors under the NER nominated cost pass through considerations is 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.[46] We consider it is appropriate for network service providers to be incentivised to mitigate the risk of major cyber events occurring, and also to mitigate the extent of damage that may be caused by them and any impact on the provision of direct control services.

If we were to accept this pass through event, the incentive on AusNet Services and other service providers to proactively manage cyber security risks and adopt best practices would likely be significantly reduced. Although AusNet Services has no control on what third parties do, it controls the cyber security and protection of its ICT systems and assets, which affects its susceptibility to cyber-attacks and the likelihood of a major cyber event. AusNet Services has a regulatory obligation to maintain the security of supply of electricity and an incentive to ensure the security of its network systems is sufficiently robust and resilient to withstand cyber-threats such that a major interruption to its technology systems and assets would not occur. We consider AusNet Services can substantially mitigate the risk and cost impact of this type of event in a forward looking manner by ensuring appropriate cyber-security protections are in place and having appropriate contingency precautions.

Our recent decisions for other distributors to not accept a major cyber event are because we consider cyber security risk is one of the key business risks an energy

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[44] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 163–167.

[45] EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p.11; ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 19 (Spencer&Co).

[46] NER, Chapter 10, *Nominated pass through event considerations* (c).

network service provider faces.[47] This risk should be largely borne by the network service provider, who is best placed to manage it, rather than consumers.[48] We consider accepting the broadly defined proposed major cyber event is likely to have the effect of passing AusNet Services' cyber-security risk to consumers and erode its incentives to manage this risk efficiently and prudently.

Our recent decisions also emphasised that all Australian utility providers operate national critical infrastructure and are subject to stringent cyber security compliance requirements.[49] We expect AusNet Services would have appropriate safeguards or contingency plans to substantially mitigate the risks and cost impacts of major cyber-attacks. Supporting this, our draft decision assessed AusNet Services' estimate of total capital expenditure, including the cyber security information and communications technology capital expenditure that it proposed.[50] This expenditure is intended for AusNet Services to strengthen its capability to proactively identity, protect, detect, respond to and recover from cyber security threats.

We have also noted in our previous decisions for other distributors that the nominated 'terrorism' pass through event could include cyber-terrorism.[51]

For the reasons discussed above, our final decision is not to accept the nominated major cyber event as currently proposed.

15.5.5 Environment protection event

Our final decision is to not accept the environment protection event proposed by AusNet Services.

AusNet Services proposed this new nominated environment protection event because it considered the costs it may incur under the new obligations of the *Environment Protection Amendment Act 2018* (Vic) are uncertain and may result in it not being able to recover its efficient costs.[52]

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47 AER, *Draft decision CitiPower Distribution Determination 2021 to 2026 - Attachment 15 Pass through events*, September 2020, pp.17-19.

48 AER, *Draft decision CitiPower Distribution Determination 2021 to 2026 - Attachment 15 Pass through events*, September 2020, pp.17-19.

49 AER, *Draft decision CitiPower Distribution Determination 2021 to 2026 - Attachment 15 Pass through events*, September 2020, pp.17-19.

50 AER, *Draft decision AusNet Services Distribution Determination 2021–26, Attachment 5 Capital expenditure*, September 2020. pp. 27-28.

51 AER, *Final decision, CitiPower Distribution Determination 2016–20, Attachment 15 Pass through events*, May 2016, pp. 19–20; AER, *Draft decision, Essential Energy distribution determination 2019–24, Attachment 14 Pass through events*, November 2018, pp.13–14.

52 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, pp. 162–163.

Consumer groups such as the CCP17 and VCO questioned the need for the proposed environmental protection event, given the apparent duplication with the existing prescribed regulatory change event in the NER.[53]

We do not consider AusNet Services' has provided a clear justification as to why regulatory obligations arising under the *Environment Protection Amendment Act 2018* (Vic) should be subject to an additional nominated pass through event. Our view is that the proposed environment protection event is already covered by the prescribed regulatory change event in the NER. While there are some additional matters set out in the proposed definitions of AusNet Services' nominated pass through event, which are not features of the prescribed regulatory change event definition in the NER, it appears there is nothing that would preclude the proposed new obligations of the *Environment Protection Amendment Act 2018* (Vic) from being covered by the prescribed regulatory change event.

The nominated pass through event considerations in the NER require the AER to consider whether a proposed nominated event is covered by a category of pass through event specified in the NER.[54] We consider that the proposed environment protection event is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to(4), specifically the prescribed "regulatory change" event. Therefore, our final decision is to not accept the environment protection pass through event proposed by AusNet Services.

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53 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 69; Headberry Partners report to VCO, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 28-29, 66.

54 NER, Chapter 10, *Nominated pass through event considerations* (a).

Table 15.2 Approved cost pass through definitions

Pass through event	Approved definition
Insurance coverage	An insurance coverage event occurs if: 1. AusNet Services: a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and 2. AusNet Services incurs costs: a) beyond a relevant policy limit for that policy or set of insurance policies; or b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and 3. The costs referred to in paragraph 2 above materially increase the costs to AusNet Services in providing direct control services. For the purposes of this insurance coverage event: 'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of AusNet Services, where those movements mean that it is no longer possible for AusNet Services to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies. 'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had: i. the limit not been exhausted; or ii. those costs not been unrecoverable due to changed circumstances. A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which AusNet Services was regulated; and AusNet Services will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business; and

Pass through event	Approved definition
	AusNet Services will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business. Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(j), the AER will have regard to: i. the relevant insurance policy or set of insurance policies for the event ii. the level of insurance that an efficient and prudent DNSP would obtain, or would have sought to obtain, in respect of the event; iii. any information provided by AusNet Services to the AER about AusNet Services' actions and processes; and iv. any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event that occurs.
Insurer credit risk	An insurer credit risk event occurs if an insurer of AusNet Services becomes insolvent, and as a result, in respect of an existing or potential 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. Note: in assessing an insurer credit risk event pass through application, the AER will have regard to, amongst other things: i. 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; and ii. in the event that a claim would have been covered by the insolvent insurer's policy, whether AusNet Services had reasonable opportunity to insure the risk with a different provider.
Natural disaster	Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2021–26 regulatory control period that

Pass through event	Approved definition
	changes the costs to AusNet Services in providing direct control services, provided the cyclone, fire, flood, earthquake or other event was: (a) a consequence of an act or omission that was necessary for the service provider to comply with a regulatory obligation or requirement or with an applicable regulatory instrument; or (b) not a consequence of any other act or omission of the service provider. Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things: (1) whether AusNet Services has insurance against the event; (2) the level of insurance that an efficient and prudent NSP would obtain in respect of the event.
Terrorism	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: 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 put the public, or any section of the public, in fear); and changes the costs to AusNet Services in providing direct control services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: i. whether AusNet Services has insurance against the event; ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.
Retailer insolvency	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:

Pass through event	Approved definition
	(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). For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the NER (as well as any subordinate terms including, without limitation, 'retailer insolvency costs', 'failed retailer' and 'billed but unpaid charges') 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 Customer Framework in Victoria

Source: AER analysis

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CCP17	Consumer Challenge Panel, sub-panel 17
distributor	distribution network service provider
DNSP	distribution network service provider
ECA	Energy Consumers Australia
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	network service provider
opex	operating expenditure
VCO	Victorian Community Organisations

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 16 Alternative control services

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

16 Alternative control services

This attachment sets out our final decision on prices, or revenues, AusNet Services is allowed to charge, or recover from, customers for the provision of alternative control services (ACS):

- ancillary network services,
- public lighting services, and
- metering services.

Alternative control services are customer specific or customer requested services and so the full cost of the service is attributed to that particular customer, or group of customers, benefiting from the service. We set service specific prices or revenues to provide a reasonable opportunity to the distributor to recover the efficient cost of each service from customers using that service.

For more information on the classification of services and the form of control applied to each of the above services, see Attachment 13 − Classification of services, Attachment 14 − Control mechanisms and/or our final *Framework and Approach* (F&A) paper for the Victorian distributors.[1]

16.1 Ancillary network services

Ancillary network services share the common characteristic of being non-routine services provided to individual customers as requested. Our F&A paper outlines several types of services that can be considered as meeting this broad definition.[2] For ease of reference, ancillary network services in this attachment is to be taken to refer to the following service groupings, unless further explanation is provided:[3]

- Auxiliary metering services
- Basic connection services
- Connection application and management services
- Network ancillary services.

Ancillary network services are either charged on a fee or quotation basis, depending on the nature of the service.

[1] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy: Regulatory control period commencing 1 January 2021*, January 2019.

[2] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy: Regulatory control period commencing 1 January 2021*, January 2019, pp. 29–34 and 100–104.

[3] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy: Regulatory control period commencing 1 January 2021*, January 2019, pp. 29–34 and 105–110.

We generally determine fee-based service price caps for the next regulatory control period as part of our determination, based on the cost inputs and the average time taken to perform each service. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty.

By comparison, prices for quoted services are based on quantities of labour and materials, with the quantities dependent on a particular task. Prices for quoted services are determined at the time of a customer's enquiry and reflect the individual requirements of the customer’s service request. For this reason, it is not possible to list prices for quoted services in our decision. However, our final decision sets labour rates to be applied to ancillary network services provided on a quotation basis.

16.1.1 Final decision

Fee-based and quoted services

Our final decision, is to:

- Accept all but one of AusNet Services’ proposed fee-based service prices. We do not accept the proposed price for security lighting reasonably reflects the efficient costs of providing these services. Our final decision substitutes the price with one we consider does reasonably reflect the efficient costs.
- Accept all but one of AusNet Services' proposed labour rates for quoted services. We do not accept the proposed senior engineer labour rates are efficient. Our final decision substitutes these labour rates with those we consider to be efficient.
- Simplify AusNet Services' four meter test services to two meter test services. In response to AGL's submission, AusNet Services stated it was amenable to simplifying its meter test services.

In our final decision, we adjust AusNet Services' proposed prices for year one (2021–22) of the 2021–26 regulatory control period for:

- actual inflation so the prices for the 2021–22 regulatory year are in nominal terms (see A Ancillary network services prices of this attachment)
- our final decision labour price growth forecasts, and
- our final decision nominal vanilla weighted average cost of capital (WACC) (see Attachment 3 – Rate of return).

Note on proposal of new services at the revised proposal stage

AusNet Services only proposed the 'Security and watchmen lights' service—and associated price—in its revised proposal.

Introducing services in revised proposals limits the extent to which stakeholders can consult and provide comments on the proposal. Our consumer engagement guideline highlights the significance of customer engagement for expenditure proposals.[4]

Stronger consumer engagement can assist in the assessment of service providers' expenditure proposals, and can raise alternative views on matters such as service priorities, capital expenditures and price structures.

X factors for ancillary network services

We determine the prices and labour rates for AusNet Services' ancillary network services in the first year of the 2021–26 regulatory control period. For each year thereafter, the prices and labour rates are determined by a price cap control mechanism that adjusts prices for inflation, an X factor and any relevant adjustments. Our final decision price cap control mechanism is set out in Attachment 14 – Control mechanisms.

As ancillary network services have a high share of labour and labour-related inputs, we use labour price growth forecasts as the ancillary network services X factor. In particular, we average wage price index growth forecasts from Deloitte Access Economics and BIS Oxford Economics to determine the X factors.

We have updated the labour price growth forecasts for our final decision to include the most recent forecasts. Our final decision X factors for ancillary network services are set out in Table 16.17 in A Ancillary network services prices of this attachment.

16.1.2 AusNet Services' revised proposal

AusNet Services accepted most of our draft decision on the prices for its fee-based services and its labour rates for quoted services. AusNet Services' revised proposal included a schedule of prices that is largely consistent with our draft decision.[5]

In response to our draft decision on fee-based services, AusNet Services:

- Identified additional costs for single phase connection services related to its own contractor's priority connections fees.[6] This led to an increase in the prices charged for single phase connection services in comparison to the initial proposal.
- Added a new fee-based ancillary network service for security and watchmen lights, consistent with our F&A.[7] [8] The year one price for this service was calculated to be

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4 AER, *Better regulation: Consumer engagement guideline for network service providers*, November 2013, p. 5.

5 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, pp. 187–189.

6 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 186.

7 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, pp. 188–189; AER, *Final framework and approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, pp. 33–34.

8 AusNet Services (along with Jemena) has proposed to operate and maintain security and watchmen lights but not their installation as an alternative control service in the 2021–26 regulatory control period. The other Victorian distributors are offering to install them as a quoted service with no additional fee to operate and maintain them.

equal to the average expected mercury vapour public lighting price over the regulatory control period.

For quoted services, AusNet Services:

- Amended its labour rates to include a margin, where the resultant rates would be below our consultant's maximum recommended total hourly rates.[9]
- Added a new senior engineer labour rate.[10] The proposed labour rate was higher than the labour rate we consider is efficient.

AusNet Services' revised proposal did not explicitly comment on the X factors to apply to ancillary network services. However, its modelling used the same approach that we accepted in the draft decision, which was to use labour price growth forecasts as the X factor.

16.1.3 Assessment approach

The regulatory framework for assessing alternative control services is less prescriptive than for standard control services. That is, there is no requirement to apply the building block model exactly as prescribed in Part C of the National Electricity Rules (NER).[11]

On this basis, our approach involves an assessment of the efficient costs of providing ancillary network services. Labour costs are the major input in the cost build-up of prices for ancillary network services. Therefore, our assessment focusses on comparing AusNet Services' proposed labour rates against maximum total labour rates, which we consider efficient.

Where AusNet Services' proposed labour rates exceed our maximum efficient labour rates, we apply our maximum efficient labour rates to determine prices. We follow this assessment process for services provided on a fee or quotation basis.

We also considered relevant stakeholder feedback raised throughout the consultation process and benchmarked AusNet Services' proposed ancillary network services prices against its prices for the 2016–20 regulatory control period and other relevant distributors. We made further adjustments to AusNet Services' ancillary network services prices where we considered it appropriate to do so.

Origin Energy noted in its submission that alternative control services can impose significant costs on customers. As such, Origin Energy appreciated the efforts made in examining the underlying cost structures associated with alternative control services.[12]

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9 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, pp. 190–191.

10 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 191.

11 NER, cl. 6.2.6(c).

12 Origin Energy, *Submission on the Victorian EDPR Revised proposal and draft decision 2021–26*, January 2021, p 2.

16.1.4 Reason for final decision

Sections 16.1.4.1 and 16.1.4.2 discuss our reasons for our final decision on AusNet Services' revised proposal where it has not accepted our draft decision or where it proposed new matters not considered in our draft decision.

Section 16.1.4.3 sets out our consideration of issues raised by AGL on the regulation of ancillary network services in general.

16.1.4.1 Fee-based services

Increase in single phase connection service prices

We accept AusNet Services' proposal to increase the price for its single phase overground and underground connection services by an additional 3.7 per cent of its contractor's fees. We are satisfied the increase reflects the efficient costs AusNet Services incurs in the provision of these services.

AusNet Services' cost build up model forecasts that seven per cent of its single phase connection services are a priority connection.[13] Priority connections occur when AusNet Services' contractor reschedules its works program (for example, due to weather or customer service issues). This leads to the contractor charging additional fees to complete the newly prioritised connections. As a result, AusNet Services increased the price of those services by seven per cent of its contractor's priority connection fee to reflect its additional costs.

In an information request, we requested AusNet Services provide reasons for using the seven per cent forecast, and whether it was based on a historical average. AusNet Services confirmed in its response that the probability was based on historical data. However, it had updated its analysis to propose a new probability of 3.7 per cent.[14]

Based on this additional information, we are satisfied the increase in prices by 3.7 per cent of AusNet Services' contractor's priority connection fees is efficient, as it reflects AusNet Services' actual costs of providing the service.

Security and watchmen lights as a new network ancillary service

We accept AusNet Services' proposal to provide the operation and maintenance of security and watchmen lights on a fee basis as it is consistent with our F&A.[15] However, we do not accept AusNet Services' proposed price and have substituted it with the price we consider efficient.

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[13] AusNet Services, *Revised regulatory proposal 2022-26 - Alternative Control - ANS fee based model*, December 2020.

[14] AusNet Services, *Information request #072,* January 2021.

[15] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy: Regulatory control period commencing 1 January 2021*, January 2019, p. 33.

In developing this service, AusNet Services modelled the year one price by averaging the projected mercury vapour (MV) 80W public lighting prices over the five-year regulatory control period. AusNet Services advised that it:

- used MV public lighting prices to derive this service's price as both services have identical approaches with the same globes, luminaires and switching arrangements,[16] and
- averaged the projected MV public lighting prices to help reduce price variations for its customers.[17]

We are satisfied with AusNet Services' explanation for deriving the price of this service by using MV public lighting prices. The price reflects the efficient costs that AusNet Services will incur for MV public lighting as the two services have identical approaches.

However, we do not accept that AusNet Services' proposed security and watchmen lights year one price is efficient. We see no reason to treat MV public lighting and security and watchmen lights differently by giving them different year one prices. AusNet Services' security and watchmen lights are subject to the price cap control mechanism. This means that regardless of the year one price, consumers will experience the same annual price variations due to inflation and X factors.

Furthermore, because security and watchmen lighting is an ancillary network service, we apply the labour price growth forecasts as the X factor (see section 16.1.1). This means that consumers face greater price variability when the year one price is higher as it causes higher annual price escalations.

Consequently, we have set AusNet Services' new security and watchmen lighting year one price to be equal to its MV lighting year one price. AusNet Services has accepted this year one price.[18]

Simplification of AusNet Services' meter accuracy tests

Our final decision consolidates AusNet Services' four single and multi-phase meter equipment test services with two equipment test services that will cover both types of meters. We consider the prices proposed by AusNet Services in response to an information request allows it to recover its efficient costs and responds to stakeholder requests to simplify its services.

In response to our draft decision, AGL submitted there was scope for AusNet Services to simplify its meter accuracy test services to be consistent with the other Victorian

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16 AusNet Services, *Information request #072,* January 2021.

17 AusNet Services, *Information request #072,* January 2021.

18 AusNet Services, *Information request #072,* January 2021.

distributors.[19] AGL also requested AusNet Services to clarify the differences between its meter accuracy tests.[20]

To advance AGL's considerations, we requested AusNet Services to provide additional information on these services and whether it was amenable to simplifying them.

AusNet Services responded that it has different prices for single and multi-phase meter accuracy tests because each phase of the meter is tested separately. This means that a multi-phase meter accuracy test would take longer than a single phase test. It also noted that its proposed price for a multi-phase meter accuracy test was similar in price to a single-phase meter test plus an additional single-phase meter.[21]

However, AusNet Services was amenable to simplifying its meter accuracy test services if a weighted average is applied. The weighted average price is derived by applying a weighting of 87 per cent to the price of tests for single-phase tests and 13 per cent to multi-phase tests. These percentages are the indicative volumes of each service that AusNet Services expects to provide in 2021–22.[22] The single price for the four services and the two weighted average prices are set out in Table 16.1.

Table 16.1 Meter test service prices, information request response ($2020–21)

Service	Meter test unit rate	Additional meter unit test rate
Meter equipment test – Single Phase	$297.72	$66.40
Meter equipment test – Multi Phase	$359.85	$98.37
Weighted average	$304.22	$70.14

Source: AusNet Services, *Information request #077,* February 2021.

We consider AusNet Services' method for deriving its weighted average prices is practical and intuitive. The resultant prices are heavily weighted towards the single phase price, which is much lower than the multi-phase price. Therefore, to ensure consistency between the Victorian distributors, we removed the distinction between phases for meter equipment tests and replace them with a single meter test rate and a single additional meter test rate. The new prices will be the weighted average of AusNet Services' previously proposed prices we previously accepted.

19 AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 3.
20 AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 3.
21 AusNet Services, *Information request #077,* February 2021.
22 AusNet Services, *Information request #077,* February 2021.

16.1.4.2 Quoted services

This section sets out our final decision on the labour rates AusNet Services uses for its quoted services. Our final decision on AusNet Services' proposed inclusion of a tax allowance in the quoted services control mechanism formula is set out in Attachment 14 – Control mechanisms.

The addition of margin to AusNet Services' quoted service labour rates

We accept AusNet Services proposal to apply a margin to its quoted service labour rates because:

- margins are included in the maximum labour rates we consider efficient, and
- the revised labour rates are below the maximum rates we consider efficient.

In response to our draft decision, AusNet Services proposed to increase its quoted service labour rates (compared to our draft decision) by a margin of 4.6 per cent. The increase was justified on the basis that the maximum rates we consider efficient, developed by our consultant Marsden Jacob Associates (Marsden Jacob), included margins in the overheads allowance when deriving the maximum rates.[23] Therefore, AusNet Services applied the margin to all but one labour category (Electrical Tester Including Vehicle & Equipment) to ensure the resultant rates would be below our maximum labour rates we consider efficient.

As set out in our assessment approach, we consider labour rates that are equal to or below the maximum labour rates developed by our consultant to be efficient. Therefore, we accept AusNet Services' proposed labour rates as they are below the maximum rates.

However, in our assessment we noted AusNet Services had applied the margin twice to its business hours labour rates.[24] In response to an information request, AusNet Services confirmed the margin should apply only once.[25] We correct for this in our final decision.

We note AusNet Services' resultant labour rates are still significantly below the maximum labour rates we consider efficient. Table 16.2 compares the business hour labour rates we consider efficient with AusNet Services' proposed labour rates.

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23 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 190.

24 AusNet Services, *Alternative Control - ANS fee based model*, 3 December 2020, 'Quoted Services'!

25 AusNet Services, *Information request #083,* February 2021.

Table 16.2 Comparison of business hour labour rates, revised proposal ($2020–21)

Service description	AER labour type	AER maximum total hourly rate – business hours	AusNet Services revised proposal (corrected for margin) – business hours
Construction Overhead Install	Field worker	$171.13	$119.17
Construction Underground Install	Field worker	$171.13	$116.39
Construction Substation Install	Field worker	$171.13	$116.39
Electrical Tester Including Vehicle & Equipment	Technical specialist	$171.13	$171.75
Planner Including Vehicle	Technical specialist	$171.13	$159.97
Supervisor Including Vehicle	Technical specialist	$171.13	$159.97
Design	Engineer	$150.14	$136.59
Drafting	Technical specialist	$171.13	$104.96
Survey	Technical specialist	$171.13	$123.63
Tech Officer	Technical specialist	$171.13	$123.63
Line Inspector	Technical specialist	$171.13	$119.17
Contract Supervision	Technical specialist	$171.13	$123.63
Protection Engineer	Engineer	$150.14	$136.59
Maintenance Planner	Technical specialist	$171.13	$123.63

Source: Marsden Jacob, *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services: Advice to the Australian Energy Regulator*, 30 June 2020, p. 10; AusNet Services, *Alternative Control – ANS fee based model*, 3 December 2020, 'Quoted Services'!, AER analysis.

AusNet Services' new senior engineer labour rate

We accept AusNet Services' proposal to include a new labour rate for senior engineers. However, we have substituted AusNet Services' proposed rate with the maximum labour rate we consider efficient.

In its revised proposal, AusNet Services stated that the proposed new labour category was for additional engineers to manage the increased number of large connections on its distribution network.[26] Table 16.3 compares the business hour labour rates we consider efficient with AusNet Services' proposed labour rates.

Table 16.3 Comparison of senior engineer labour rates, revised proposal ($2020–21)

Service description	AER labour type	AER final decision maximum total hourly rate – business hours	AusNet Services revised proposal – business hours
Senior Engineer	Senior Engineer	$196.34	$244.84

Source: Marsden Jacob, *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services: Advice to the Australian Energy Regulator*, 30 June 2020, p. 10; AusNet Services, *Alternative Control – ANS fee based model*, 3 December 2020, 'Quoted Services'!.

To calculate its proposed rate, AusNet Services:

- averaged our consultant's maximum recommended senior engineer rate with Australian Energy Market Operator's (AEMO's) charge-out rate for engineers ($270), then
- applied a margin consistent with the approach discussed in section 16.1.4.2.[27]

AusNet Services justified the higher price by citing the increased demand for senior engineers due to an increase in renewable projects.[28]

AusNet Services considered it appropriate to include the AEMO engineer call-out rate in deriving its proposed rates for two reasons:

- The skillsets involved in connecting large customers at the distribution level were broadly similar to connecting them at the transmission level.
- AusNet Services competes with AEMO for the same pool of senior engineers and therefore AEMO's rates are reflective of the market tested costs that it faces. [29]

We are not satisfied that AusNet Services' proposed rate for senior engineers is efficient. We consider the rationale behind proposing a higher rate for senior engineers (compared to our maximum labour rate) was not supported by the evidence.

First, we note Marsden Jacob's method to derive its benchmark efficient maximum labour rates for senior engineers. It used the highest salaries in the Hays 2019–20 energy sector salary data to derive labour rates with a bottom-up model. We consider

[26] AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 191.

[27] AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 191; AusNet Services, *Alternative Control - ANS fee based model*, 3 December 2020, 'Quoted Revised Proposal 2021'!

[28] AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 191.

[29] AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p. 191.

that using the Hays salary data from the previous financial year reasonably reflects the current labour market conditions for senior engineers in the energy sector.

Second, Marsden Jacob undertook additional analysis on the senior engineer labour rate after the other Victorian distributors proposed labour rates that were significantly higher than its benchmark rates.[30] Marsden Jacob found that, according to the Hays salary data, the maximum salaries for a number of senior engineering jobs has been declining significantly in Melbourne. In comparison with other jurisdictions, the senior engineer rate in Victoria tends to be 'in the middle of the pack'.[31] In other words, the Hays salary data does not suggest an increase in demand for senior engineers.

Finally, we consider that AusNet Services provided insufficient evidence that the work of AEMO's call-out engineers is similar to AusNet Services' engineers. We requested AusNet Services to outline the similarities and differences in the skills and responsibilities of its engineers and AEMO's engineers in greater detail. AusNet Services explained that while its engineers have similar modelling skills and level of experience compared to AEMO's, they have different areas of focus.[32]

To support its proposal, AusNet Services provided a table comparing the skills and experience required in an AEMO lead engineer job advertisement with one of its own job advertisements. The table mostly consisted generic criteria such as relevant tertiary qualifications and experience, leadership skills and willingness to support others. The comparison did not provide a specific list of common tasks or responsibilities that could support the claim that the two jobs were similar enough to compare labour rates.

This lack of detail makes it difficult to assess with any degree of certainty that the two engineering roles are comparable. There remains the possibility that AEMO's engineers may have different responsibilities that would merit additional compensation. Alternatively, AEMO may have other cost drivers unrelated to salary that could explain the difference between the labour rates.

For these reasons, we do not believe there is a reasonable justification in applying a labour rate that is higher than Marsden Jacob's. As a result, we have substituted in our efficient rate being the Marsden Jacob's recommended senior engineer rate, escalated by forecast labour price growth for 2021–22. We note that the other Victorian distributors have already accepted our decision to apply Marsden Jacob's senior engineer labour rate (or otherwise proposed senior engineer labour rates lower than Marsden Jacob's).[33]

30 Marsden Jacob, *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services: Advice to the Australian Energy Regulator*, 30 June 2020, pp. 12–13.

31 Marsden Jacob, *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services: Advice to the Australian Energy Regulator*, 30 June 2020, p. 12.

32 AusNet Services, information request #072, January 2021.

33 CitiPower, *Revised Regulatory Proposal 2021–26*, December 2020, p. 127; Jemena, *Revised Regulatory Proposal 2021–26: ATT 09-01 Response to the AER's draft decision - Alterative control services*, December 2020, p. 28; Powercor, *Revised Regulatory Proposal 2021–26*, December 2020, p. 141; United Energy, *Revised Regulatory Proposal 2021–26*, December 2020, p. 124.

16.1.4.3 Issues raised on the regulation of ancillary network services

In its submission, AGL considered there is scope to improve the regulation of ancillary network services by standardising and simplifying the services that distributors offer.[34] This would allow retailers operating across the five distribution regions in Victoria to streamline their operations. For example, AGL noted how each Victorian distributor had different criteria on how they charged their connection service fees.

We agree with the feedback from AGL that there is potential to standardise and simplify the ancillary network services offered across distributors and even across jurisdictions. The distributors different naming conventions, criteria for services, and service descriptions makes it difficult for us and other stakeholders to compare and benchmark prices. The standardisation and simplification of ancillary network services is an issue that merits further investigation in the future.

AGL further noted that it was important for distributors to justify differences in their after-hours rates with their business-hours rates. AGL considered distributors should not automatically assume their after-hours rates can be automatically marked up by 75 per cent.[35] This was in reference to the Marsden Jacob recommendation that after-hours labour rates be capped at 1.75 times the relevant ordinary rate.

In AusNet Services' case, most of its after-hours labour rates were above the 75 per cent mark-up cap recommended by Marsden Jacob. In our draft decision, we substituted those after-hours rates to reflect that cap, which AusNet Services accepted as part of its revised proposal. We will continue to monitor the after-hour mark-ups in future determinations.

16.2 Metering

We are responsible for the economic regulation of the regulated metering services provided by the Victorian distributors. Metering services include the maintenance, reading, data services and recovery of capital costs related to installing meters.

Metering assets are used to measure electrical energy flows at a point in the network to record consumption for the purposes of billing, and include:

- type 5 (interval) and type 6 (accumulation) meters, including meters installed as part of the Advanced Metering Infrastructure (AMI or smart metering) program in Victoria, which are classified as type 5-6 meters, and
- type 7 meters, which relate to unmetered connections with predictable energy consumption patterns (such as public lighting connections).

Unlike other jurisdictions in the National Electricity Market (NEM), the Victorian distributors are the monopoly providers of most metering services, including smart

[34] AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 2–3.

[35] AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

metering services. Since 2017, metering services have become contestable services in some jurisdictions and can be provided by a retailer or a third party instead, but not in Victoria.[36]

AusNet Services' current meter population comprises of 98.6 per cent AMI meters and 1.4 per cent non-AMI meters.[37]

In this section, we explain our final decision for AusNet Services on the following metering services:

- Type 5 and 6 (incl. smart metering) services, and
- Metering exit fees.

Our final decision on other regulated metering services (for example, type 7 metering services and auxiliary metering services other than metering exit fees) is set out in section 16.1.1 on ancillary network services.

16.2.1 Final decision

Our final decision is to:

- Not accept AusNet Services' proposed cost allocations between alternative control services to standard control services for the following IT and communication system costs:
    - Mesh (UIQ)-WiMax licenses (operating expenditure (opex)) and mesh network maintenance (capital expenditure (capex))
    - Telstra backhaul costs.

  We apply our draft decision allocations of these costs being 94 per cent to alternative control services and 6 per cent to standard control services.

- Not accept AusNet Services' proposed revenues for type 5 and 6 (incl. smart metering) services.

  We substitute alternative revenues for type 5 and 6 (incl. smart metering) services calculated by:
    - applying our alternative cost reallocation calculations, and
    - applying our final decision rate of return, labour price growth forecasts, and inflation forecasts consistent with standard control services.

- Not accept AusNet Services' proposed metering exit fees.

  We substitute alternative charges based on our changes to forecast capex and opex.

[36] In some instances, a customer is charged for metering services from both the distributor and retailer. More information on these arrangements can be found in the AER's distribution determination for each distributor.

[37] AusNet Services, *Metering Asset Management Strategy - Part 1,* January 2020, p.11.

In our final decision, we adjust AusNet Services metering model to derive charges for year one (2021–22) of the 2021–26 regulatory control period for:

- actual inflation and inflation forecast consistent with standard control services,
- our final decision labour price growth forecasts, and
- our final decision nominal vanilla WACC (see Attachment 3 – Rate of return).

Our final decision also includes an adjustment in the first year (2021–22) of the 2021–26 regulatory control period to true-up the allowed revenue amounts we set for the six-month extension period (see section 16.2.1.5).

16.2.1.1 Allocation of AMI IT and communication costs

We do not accept AusNet Services' proposed reallocation of certain AMI communication and IT costs from alternative to standard control services. Our final decision on the allocation between alternative and standard control services is set out in Table 16.4 below.

Table 16.4 Final decision – AusNet Services' allocation of AMI IT and communication costs

System	Current allocation	Initial proposal	Draft decision	Revised proposal	AER final decision
CAPEX					
CNMS Lifecycle Management for reporting and (monitoring)	100% ACS	50%:50% ACS:SCS	94%:6% ACS:SCS	94%:6% ACS:SCS	94%:6% ACS:SCS
UIQ	100% SCS	100% SCS	100% SCS	100% SCS	100% SCS
3G phase out	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS
Wimax network asset maintenance	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS
Mesh network asset maintenance	100% ACS	50%:50% ACS:SCS	94%:6% ACS:SCS	80%:20% ACS:SCS	94%:6% ACS:SCS
PolicyNet (mesh lifecycle management)	100% SCS	100% SCS	100% SCS	100% SCS	100% SCS
OPEX					
Mesh (UIQ) and WiMax (Policy Net)	100% ACS	50%:50% ACS:SCS	94%:6% ACS:SCS	80%:20% ACS:SCS	94%:6% ACS:SCS
EnergyIP (EIP)	100% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS
CIS	100% SCS	100% SCS	100% SCS	100% SCS	100% SCS
Reporting and Monitoring GD	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS

System	Current allocation	Initial proposal	Draft decision	Revised proposal	AER final decision
Telstra Backhaul	100% ACS	50%:50% ACS:SCS	94%:6% ACS:SCS	64%:36% ACS:SCS	94%:6% ACS:SCS
DMACS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS	50%:50% ACS:SCS
IBM	95%:5% ACS:SCS	95%:5% ACS:SCS	95%:5% ACS:SCS	95%:5% ACS:SCS	95%:5% ACS:SCS

Note: ACS is alternative control services, SCS is standard control services

Sources: AER analysis; AusNet Services, *Electricity Distribution Price Review 2022–26 Appendix 9D*, January 2020, pp.4–6.

16.2.1.2 Type 5 and 6 (incl. smart metering) services revenue

Our final decision allows a revenue requirement for type 5 and 6 (incl. smart metering) services for the 2021–26 regulatory control period of $300.79 million ($nominal) compared to AusNet Services' proposed $291.09 million ($nominal).

Table 16.5 sets out our approved revenue requirement for the 2021–26 regulatory control period.

Table 16.5 Final decision – metering annual revenue requirement for the 2021–26 regulatory control period ($ nominal)

	2021–22	2022–23	2023–24	2024–25	2025–26
Depreciation	27.06	30.02	32.73	35.30	37.53
Return on capital	10.07	9.30	8.38	7.37	6.31
Opex[a]	15.62	16.25	16.83	17.29	17.75
Net tax allowance	3.10	2.34	2.35	2.57	2.84
Unsmoothed revenue requirement	55.85	57.91	60.29	62.54	64.44
X factor (%)[b]	-21.60%	-0.75%	-0.75%	-0.75%	-0.75%
Smoothed revenue requirement	56.92	58.50	60.11	61.78	63.48

Source: AER, *Final decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, April 2021.

(a) Opex includes debt raising costs.

(b) The X factor for metering services from 2022–23 to 2025–26 will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

Having calculated the total revenue requirement for the 2021–26 regulatory control period, we smooth the revenue for each regulatory year across that period. This step reduces revenue variations between years, and calculates the expected revenue and X factor for each year. The X factors equalise (in net present value terms) the total expected revenues to be earned by the distributor with the total revenue requirement for the 2021–26 regulatory control period. For AusNet Services, this net present value is $262.81 million ($2020–21).

16.2.1.3 Metering charges

Our final decision will lead to a higher net present value of AusNet Services' total metering revenue (smoothed) over the 2021–26 regulatory control period than that proposed by AusNet Services in its revised proposal. As metering services[38] are subject to a revenue cap, we have not set metering charges in this final decision. Actual metering charges will be approved during our annual pricing process.

Broadly we expect the price path to follow the X factors included in Table 16.5 and Table 16.6. Table 16.6 provides the first year adjustment (2021–22) relative to the revenues the last year of the 2016–20 regulatory control period and X factors for remaining years of 2021–26 regulatory control period. We further note that negative first year adjustments and X factors reflect increases in revenues due to the CPI–X revenue control formula.Table 16.7 sets out the expected or 'smoothed' revenue for the 2021–26 regulatory control period.

Table 16.6 Final decision first year adjustments and X factors for remaining years of 2021–26 regulatory control period (per cent)

	2021–22	2022–23	2023–24	2024–25	2025–26
Proposal	7.23[1]	-0.89	-0.89	-0.89	-0.89
Draft decision	-20.54[1]	0.00	0.00	0.00	0.00
Revised proposal	-18.16	0.00	0.00	0.00	0.00
Final decision	-21.60	-0.75	-0.75	-0.75	-0.75

Source: AER, *Draft decision AusNet Services, distribution determination 2021–26 – Metering PTRM*, September 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – Metering PTRM – FY22-26*, January 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – EDPR 2022–26 Revised proposal – PTRM model (2022–26)*; *AER, Final decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, April 2021.

Note: AusNet Services' initial proposed first year adjustment was calculated from its proposed 2021 revenue for the six-month extension period 1 January 2021 to 30 June 2021, doubled to account for a full year, and does not include any adjustments to reflect our 2016 final decision on AMI transition charges applications. The first year movement for our final decision is calculated from approved 2020 revenue, and indexed to $2020–

[38] AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy - Regulatory control period commencing 1 January 2021*, January 2019. See also attachment 14 of this draft decision.

21 for comparison. This 2020 approved revenue that has been used as a base includes a downward adjustment as a result of our December 2016 final decision on AMI transition charges applications. Accordingly our final decision first year adjustment is not comparable to AusNet Services' proposed first year adjustment.

Table 16.7 Final decision smoothed revenue 2021–26 ($ million, nominal)

Smoothed revenue	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Proposal	54.76	56.60	58.51	60.47	62.51	292.85
Draft decision	56.64	57.98	59.36	60.77	62.21	296.95
Revised proposal	55.52	56.84	58.19	59.57	60.98	291.09
Final decision	56.92	58.50	60.11	61.78	63.48	300.79

Source: AER, *Draft decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, September 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – Metering PTRM – FY22–26*, January 2020; *Electricity distribution price review 2022–26 – Supporting document – EDPR 2022-26 Revised proposal – PTRM model (2022–26)*, December 2020; AER, *Final decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, April 2021.

16.2.1.4 Metering exit fees

Our final decision metering exit fees reflect adjustments we made to the building block components for type 5 and 6 (incl. smart metering) revenue. These metering exit fees reflect:

- apportionment of the meter, IT, communications, and any other regulated asset base to reflect foregone revenue based on the average remainder of life of an asset
- administration costs of removing the meter
- tax allowances, and other relevant costs.

These costs are sourced from the calculations of the building block components for type 5 and 6 (incl. smart metering) revenue, and are therefore subject to the same assessment and reasoning as for the type 5 and 6 (incl. smart metering) revenue.

Our final decision metering exit fees for 2021–22 are set out in B Type 5 and 6 (incl. smart metering) metering exit fees. Prices for subsequent years will be determined by the control mechanism formula set out in Attachment 14 – Control Mechanisms. Our final decision on the X factors for metering exit services is also set out in B Type 5 and 6 (incl. smart metering) metering exit fees.

16.2.1.5 True-up for six month extension period

Our final decision also includes an adjustment of $14,989 ($2020–21) in the first year (2021–22) of the 2021–26 regulatory control period to true-up the allowed revenue amounts we set for the six-month extension period. We used a placeholder WACC to determine the allowed revenues for the six-month extension period. Now that the actual WACC has been determined for this period, an adjustment is required to account for the differences between the placeholder and actual WACCs.

The adjustment will be made through the C factor as set out in Attachment 14 – Control mechanisms. The true up for the placeholder WACC is discussed further in Attachment 3 – Rate of return.

16.2.2 AusNet Services' revised proposal

AusNet Services accepted most aspects of our draft decision for metering services, except for our allocation of some type 5 and 6 IT and communication systems costs from alternative to standard control services.

AusNet Services also made changes relating to the labour price growth forecasts and inflation.

16.2.2.1 Cost allocation

AusNet Services did not accept our draft decision cost allocation of 94 per cent to alternative control services and 6 per cent to standard control services for its Mesh (UIQ[39])-WiMax licenses, mesh network asset maintenance and Telstra Backhaul.[40]

In response, AusNet Services proposed a revised allocation for:

- Mesh (UIQ)-WiMax licenses (opex) and mesh network maintenance (opex and capex) of 80 per cent to alternative control services and 20 per cent to standard control services, and
- Telstra Backhaul of 64 per cent to alternative control services and 36 per cent to standard control services as set out in Table 16.8.[41]

AusNet Services allocation of Mesh licenses and mesh network asset maintenance costs is driven by the relative costs of its UIQ and SIQ[42] licence fees. This differs from AusNet Services initial proposal to allocate these costs based on meter data volumes.

For its Telstra backhaul costs, AusNet Services continued to use meter data volumes to allocate costs. However, an adjustment was made to account for the smaller size of power quality data required to support is standard control services, which resulted in an allocation of 64 per cent to alternative control services and 36 per cent to standard control services.[43]

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39 UIQ is the main application providing core metering functions.

40 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p.179.

41 AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p.179.

42 SIQ is a complementary product to collect additional information such as power quality (standard control services).

43 AusNet Services, *Information Request #066*, December 2020

AusNet Services also submitted that collection of power quality data from only 1 per cent of meters (as per our draft decision) would erode benefits from smart meters, including reduced ability to detect faults and monitor the network[44] as discussed under section 16.2.4.1.

Table 16.8 AusNet Services proposed allocation of AMI communication capex and opex

Reallocation of AMI comms capex and opex	AusNet initial proposal	AER draft decision	AusNet revised proposal	Reason for allocation
Mesh (UIQ) Licensing Opex and Mesh network asset maintenance (Capex)	50% ACS 50% SCS	94% ACS 6% SCS	80% ACS 20% SCS	AusNet Services noted UIQ & Mesh licenses cover annual support and maintenance costs for UIQ and SIQ. SIQ licence is used for SCS purposes so allocated this licence component to SCS.
Telstra Mesh 'Backhaul'	50% ACS 50% SCS	94% ACS 6% SCS	64% ACS 36% SCS	AusNet Services noted Telstra charges cover the transport of all data collected from its meters to internal systems. AusNet Services revised its allocation based on data volumes 64% ACS and 34% SCS; while more data is collected by SIQ (used exclusively for SCS purposes), the size of data is much smaller.

Source: AusNet Services, *Revised Regulatory Proposal 2022–26*, 3 December 2020, p.179.

16.2.2.2 Type 5 and 6 (incl. smart metering) services revenue requirement

AusNet Services revised proposal included a revenue requirement of $291.1 million ($ nominal) or $271.1 million ($2020–21), with $78.1 million ($2020–21) in metering capex and $73.8 million ($2021–22) in metering opex.

16.2.2.3 Annual metering charges

AusNet Services revised annual metering charges are set out in Table 16.9 below.

Table 16.9 AusNet Services proposed metering service charges ($ nominal)

Meter type	2021–22	2022–23	2023–24	2024–25
Single phase single element	62.12	62.57	63.02	63.58
Single phase two element with contactor	71.60	72.10	72.60	73.00
Multiphase	83.45	83.90	84.42	84.90

[44] AusNet Services, *Revised Regulatory Proposal 2022–26*, December 2020, p.180.

Multiphase with contactor	91.54	92.00	92.50	92.90
Multiphase CT connected	114.46	115.89	116.00	116.80

Source: AusNet Services, *Revised Regulatory Proposal 2022–26,* December 2020, p.181.

16.2.2.4 Metering exit fees

AusNet Services revised meter exit fees as set out in Table 16.10 below.

Table 16.10 AusNet Services proposed meter exit fees ($ nominal)

Meter type	2022	2022–23	2023–24	2024–25
Single phase single element	365.02	349.59	331.07	310.00
Single phase two element with contactor	361.97	346.93	328.81	308.12
Multiphase	363.69	348.45	330.11	309.22
Multiphase with contactor	363.69	348.45	330.11	309.22
Multiphase CT connected	363.86	348.59	330.23	309.32

Source: AusNet Services, *Revised Regulatory Proposal 2022–26,* December 2020, p.181

16.2.3 Assessment approach

In our final Framework and Approach, we classified type 5 and 6 (incl. smart metering) services and Metering exit services as alternative control services.[45]

16.2.3.1 Type 5 and 6 (incl. smart metering) services revenue

As type 5 and 6 (incl. smart metering) services are classified as an alternative control service, we have a greater discretion under the NER in making our assessment compared to standard control services.[46]

The regulatory framework for assessing alternative control services is less prescriptive than for standard control services. That is, there is no requirement to apply the building block model exactly as prescribed in Part C of the NER.[47]

Consistent with the approach adopted for our draft decision and the current regulatory control period we have chosen to apply a limited version of a building block approach[48] for our final decision.

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45 AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy - Regulatory control period commencing 1 January 2021*, January 2019.

46 NER, cl. 6.2.6(c).

47 NER, cl. 6.2.6(c).

48 The building block model calculates the allowed revenue for a regulated business for each year of the regulatory control period. Where the revenue requirement = opex + depreciation + tax + (WACC x regulatory asset base).

For our final decision we also had regard, where relevant, to:

- the wider regulatory context in determining the allocation of metering service costs, including the possibility of Victoria adopting a competitive metering framework at some point in the future
- cost allocation principles, and particularly our Cost Allocation Methodology Guideline[49] and the approved Cost Allocation Methodology for each distributor[50]
- consistency of approach with other regulated services, including the WACC and labour price growth forecasts used for standard control services
- comparisons between the Victorian distributors
- the Victorian distributors revised proposals, and
- stakeholder feedback in response to our draft decision.

16.2.3.2 Cost allocation

In our draft decision, we affirmed that some AMI system costs are shared costs between alternative and standard control services. We noted meter data volumes are an appropriate causal allocator of the associated shared costs.[51]

Our draft decision determined the collection of power quality data from 1 per cent of meters is sufficient to support AusNet Services distribution functions. On this basis, we determined 94 per cent of costs be allocated to alternative control services and 6 per cent to standard control services. We considered this supported not only the appropriate recovery of costs from relevant customers, but also enabled efficient price signals to be sent regarding the costs of providing the service.[52]

In assessing AusNet Services revised proposal, we focused on the scope of the causal allocator – meter data volumes – with respect to the frequency of data collection and the meter population.

Our analysis and reasons are set out in section 16.2.4.1.

16.2.3.3 Metering exit fees

Metering exit services allow the distributor to recover the written down value, as well as the efficient costs of removing and disposing, of AMI meters. This currently occurs

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The building block model requires inputs/forecasts for each year of the regulatory control period. These include; the regulatory asset base, opex, capex, interest rates, inflation and incentive payments. Our metering building block model is 'limited' because it does not include any adjustment for incentive schemes.

49 AER, *Victorian electricity distribution network service providers - cost allocation guidelines*, June 2008.

50 AusNet Services, *Electricity Distribution Cost Allocation Method*, September 2019.

51 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.3.

52 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.38-41.

when an existing site with multiple meters, such as an apartment building becomes an embedded network, resulting in the removal of existing meters.[53]

Consistent with the approach for our draft decision, the inputs we used to calculate metering exit fees for our final decision are:

- Our final decision on AusNet Services' opening metering asset base value for type 5 and 6 (incl. smart metering) services as of 1 July 2021, split into meter categories (meter, IT and communications) for the purpose of modelling the exit fee, as opposed to the broader category of 'remotely read interval meter'.
- Our final decision on forecast metering capex and opex for type 5 and 6 (incl. smart metering) services for AusNet Services' 2021–26 regulatory control period.
- Depreciation lives (meters – 15 years, communications and IT – 7 years), which we accept in this final decision.

Our analysis and reasons are set out below in section 16.2.4.

16.2.4 Reason for final decision

16.2.4.1 Cost allocation

We agree with stakeholders such as Department of Environment, Land, Water and Planning, Energy Consumers Australia (ECA), our Consumer challenge panel, sub-panel 17 (CCP17) and the Victorian electricity distributors that the AMI infrastructure and communication systems can be used to provide a range of distribution services, including standard control services.[54] As such, some of the AMI shared costs will need to be allocated to both alternative and standard control services. A view endorsed by ECA and the CCP17.[55]

ECA submitted that in a market where there is no metering competition, the allocation of costs between alternative and standard control services makes little difference to the customer who pays for the entire bundle.[56] Further, ECA submitted that, in the absence of metering competition or a need to compare metering costs across jurisdictions, it had no objection to the reallocation of costs to standard control services.[57]

In our assessment, we have been mindful to seek an appropriate allocator to apportion AMI shared costs between alternative and standard control services to ensure prices

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53 AER, *Final framework and approach: AusNet Services, CitiPower, Jemena, Powercor and United Energy - Regulatory control period commencing 1 January 2021*, January 2019

54 Department of Environment, Land, Water and Planning, *Victorian Government submission on the electricity distribution price review 2021–26*, June 2020, pp.4-5; Spencer & Co Business, *Report to ECA - Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, June 2020, p. 37; CCP17 *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021.

55 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 18; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 95.

56 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 18.

57 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 18.

reflect the respective underlying efficient costs. This is particularly pertinent should metering services in Victoria become contestable in the future to reduce the risk of cross-subsidies. The Victorian distributors and their competitors should face similar underlying costs in providing these services. As noted by the CCP17, AMI data can be used to support network operations, however metering remains fundamentally required for the purposes of determining energy consumption and retail competition.[58]

In our draft decision, we agreed data volumes are an appropriate driver of AMI shared costs and could be used to allocate costs. However, we did not accept AusNet Services proposed meter data requirements of collecting power quality data from 85 per cent of meters and the 50 per cent reallocation of AMI communication costs to standard control services for the following services:[59]

- AMI Network Head End Solution (WiMAX and Mesh)
- Meter Data Management System (MDMS) – EnergyIP
- Telstra costs for data usage to transport data from the AMI network; and
- Labour and support for the above systems.

Based on our assessment, we determined AusNet Services only needed to collect power quality data from 1 per cent of AMI meters to support its distribution network functions. We considered this a more appropriate allocation of costs, supporting not only the appropriate recovery of costs from relevant customers, but also enabling efficient price signals to be sent regarding the costs of providing a given service.

Collecting power quality data from 1 per cent of meters resulted in a cost allocation based on meter data volumes of 94 per cent to alternative control services and 6 per cent allocated to standard control services (See our draft decision Attachment 16 – Alternative control services, section 16.2.4 reasons for draft decision).[60]

In its revised proposal, AusNet Services accepted most of our draft decision for cost allocations, except for the allocation proportions for Mesh licensing opex, mesh network asset maintenance (capex) and Telstra mesh backhaul.[61]

Our assessment of each of these is set out below.

Mesh licensing opex and mesh network asset maintenance capex

We do not accept AusNet Services revised proposal to allocate 80 per cent of its mesh licensing opex and mesh network asset maintenance capex to alternative control

58 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 95.

59 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.38-41.

60 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.38-41.

61 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p.179.

services and 20 per cent to standard control services. Our final decision is to maintain our draft decision allocation of 94 per cent to alternative control services and 6 per cent to standard control services. Our final decision allocations are based on the collection of power quality data from 1 per cent of the meter population.

In its revised proposal, AusNet Services changed its approach to allocate costs. Rather than allocations based on data volumes, AusNet Services allocated costs based on the license fees for UIQ and SIQ[62] applications, and where the costs are charged per meter.[63] The relative costs of the licensing agreements per meter are 80 per cent for UIQ (alternative control services) and 20 per cent for SIQ (standard control services).

In response to our information requests, AusNet Services advised it rolled out SIQ to meet new obligations in the new electricity distribution code.[64] To comply with these obligations, AusNet Services submitted that voltage (power quality) data must be collected from 100 per cent of meters associated with each feeder/substation.

We do not agree that the Electricity Distribution Code (the Code) requires AusNet Services to capture voltage data from 100 per cent of meters.[65] We consider the Code requires AusNet Services to publish an average voltage for each Voltage Control Section.[66] Rather, we consider that one efficient method to comply with the Code would be to capture voltage data for one meter (or in some circumstances a small number of meters) per Voltage Control Section and then calculate or model the control section voltage.

As such, we maintain our draft position of collecting data from 1 per cent of meters would efficiently meet this requirement. As we note below, the provision of distribution services through the AMI network should be done in an efficient manner.

In addition to the new obligations in the Code, AusNet Services also submitted that collecting data from less than 100 per cent of meters will have a material impact on existing capabilities. Any reduction in power quality data collection would erode the benefits customers receive from smart meters, including:

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62 UIQ is the main application providing core metering functions and SIQ is a complementary product to collect additional information such as power quality (standard control services).

63 AusNet Services, *Information request #066*, December 2020.

64 See https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/electricity-distribution-code/electricity-distribution-code-review-2019/technical-standards-electricity-distribution-code-2019-review.

65 See Schedule 1, of the electricity distribution code - https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/electricity-distribution-code/electricity-distribution-code-review-2019/technical-standards-electricity-distribution-code-2019-review.

66 See table 6 of Schedule 1 of the electricity distribution code, which sets out, The voltage data to be published is the 10-minute averaged voltage data over 3 months (for each time period identified in Table 6, which commences on the first day of the month at the start of the relevant 3 month period and ends on the last day of the final month of the relevant 3 month period) of the aggregated advanced metering infrastructure population for the "Voltage Control Section" column https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/electricity-distribution-code/electricity-distribution-code-review-2019/technical-standards-electricity-distribution-code-2019-review.

- Improved low voltage (LV) network visibility, which helps minimise voltage issues and voltage complaints.
- Network grooming: Identifying and resolving network imbalance, and determining the most prudent network augmentation projects.
- Cross referencing error identification to ensure customers are correctly assigned to a feeder and therefore receive outage notifications for planned works (we note that our engagement, including with the Customer Forum, highlighted the importance of effective communication on outages).
- A more accurate assessment for distributed energy resources (DER) capacity on the network at a customer's specific location – information that is essential for customers looking to gain solar pre-approval of their applications (discussed in further detail below).
- Identification of DER non-compliance, which can occur where a customer has installed unapproved or excess DER on the network (discussed in further detail below).
- Monitoring loss of neutral incidents (discussed in further detail below).
- Monitoring and resolving non-technical losses, such as energy theft.[67]

We observe that other jurisdictions in the NEM have limited penetration of AMI meters compared to the Victorian electricity distribution networks. As a result, the electricity distributors operating in these other jurisdictions do not rely on the AMI infrastructure to deliver network services similar to the ones described above. Most of these services, including loss of neutral (discussed below), are adequately managed by use of non-AMI infrastructure. Therefore, we consider the provision of distribution services through the AMI infrastructure should only be carried out to the extent it is efficient to do so.

As noted, we agree that use of AMI infrastructure to collect power quality data can support the distribution network and provides benefits to customers. In our draft decision, we recognised these benefits by allocating an efficient portion of AMI IT and communication costs to standard control services.[68]

However, AusNet Services has provided only anecdotal evidence to support its position that the high frequency and high volumes of data collection is the efficient option for providing these services when quantifying the benefits to customers. Our assessment is that AusNet Services has overstated the efficient level of data collection required (power quality data every 5 minutes from 85 per cent of its meters and alarm data (30 alarms/day) from all of its AMI meters) to support these services.

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67 AusNet Services, *Information request #090*, February 2021.

68 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, Table 16.22 p.51.

As set out in our draft decision, we consider AusNet Services only needs to collect power quality data from 1 per cent of its AMI meters to support its distribution network functions. We consider this translates into a more appropriate allocation of costs, supporting not only the appropriate recovery of costs from relevant customers when the benefits to customers are quantified, but also enabling efficient price signals to be sent regarding the costs of providing a given service.

Loss of netural

We agree that collecting power quality data from AMI meters is an efficient way to manage loss of neutral faults. However, we consider AusNet Services has overstated the efficient level of data required to perform this service.

We note loss of neutral is a process that generally occurs gradually over time (months to years), or is associated with installation changes such as replacing service mains. We also note that loss of neutral impacts a small number of installations each year (typically 0.2 per cent or less) at a given point in time.

Given the gradual degradation process and relatively small amount of installations that are affected, we do not consider it necessary or efficient to collect power quality data every 5 minutes from 85 per cent of meters in order to monitor loss of neutral.

We consider that monitoring loss of neutral should closely follow the profile of how the fault develops. Therefore, an efficient use of the AMI network to manage the loss of neutral is to collect a materially lower frequency and volume of data. We consider the collection of power quality data from 1 per cent of the meter population is more appropriate and efficient when the benefits to customers are quantified.

Distributed energy resources (DER)

We recognise that in areas where there is a high penetration of DER exporting into the network that distributors may want to capture power quality data to manage high and low voltage problems.

However, we consider that data only needs to be collected from a small number of sites per low voltage feeder. Over the total network, we consider it sufficient to collect power quality data from approximately 1 per cent of AMI meters for this purpose.

Telstra backhaul opex costs

We do not accept AusNet Services revised proposal to allocate 64 per cent of its Telstra backhaul costs to alternative control services and 36 per cent to standard control services. Our final decision is to maintain our draft decision allocation of 94 per cent to alternative control services and 6 per cent to standard control services based on the collection of power quality data from 1 per cent of the meter population

In its revised proposal, AusNet Services proposed allocation is based on the collection of power quality data from 85 per cent of meters.[69] AusNet Services reduced the volume to 10 per cent to account for the smaller size of power quality data collected.

We do not consider AusNet Services' proposed meter data requirements and consequently its reallocation of costs is efficient. The volume of data proposed is still significantly larger than what we consider as reasonable.

As set out in our draft decision, we consider AusNet Services only needs to collect power quality data from 1 per cent of AMI meters to support its distribution network functions.[70] We consider this a more appropriate allocation of costs, supporting not only the appropriate recovery of costs from relevant customers, but also enabling efficient price signals to be sent regarding the costs of providing a given service.

Future assessments of metering costs and changes in cost allocation

We will continue to focus on ensuring prices reflect the respective underlying efficient costs for our future assessments of AMI cost allocations between alternative and standard control services.

We would expect where allocations are proposed to change, the Victorian distributors would provide us and stakeholders with comprehensive economic analysis setting out the costs and benefits to customers as to:

- why the provision of standard control services through the AMI network is the efficient approach to deliver these services
- what efficiencies are delivered to the distributor and how these efficiencies are manifesting in cost savings for operating the network
- why particular levels of data collection is efficient, and/or
- why an alternative causal allocator than data volumes is appropriate.

For our assessment of AusNet Services' AMI cost allocations in this determination, we note this level of detailed economic analysis was not provided. As noted above, AusNet Services only provided anecdotal evidence to support its proposal that high frequency and high volumes of data collection is the efficient option for providing these services when quantifying the benefits to customers.

Future cost allocation assessments may also include a detailed assessment of whether the costs to be allocated to operating or capital expenditure for standard control services reasonably reflect the prudent and efficient costs. This detailed assessment would apply to any increase or new costs related to metering services for alternative control services.

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69 AusNet Services, *Information request #066,* January 28.

70 AER, *Draft Decision AusNet Services Distribution Determination 2021–26 Attachment 16 Alternative control services*, September 2020, p.41

Finally we note that Victoria is the only NEM jurisdiction without competition in metering. This was a policy decision taken by the Victorian government. We advise that any future proposal on the cost allocation of metering services include the Victorian government as a stakeholder.

Overall, our assessment approach would ensure the Victorian distributors are only recovering costs that reasonably reflect the prudent and efficient costs in providing alternative and standard control services; balanced against the costs and benefits to consumers and any future competition for metering services in Victoria.

16.2.4.2 Price growth forecasts and inflation

We have updated the metering post-tax revenue model (PTRM) and metering capex and opex models to include our final decision inputs relating to the rate of change, inflation and labour price growth forecasts. For our labour price growth forecasts for metering services we apply the average of wage price index growth forecasts from Deloitte Access Economics and BIS Oxford Economics.

We also updated our models to correct an escalation error in our draft decision, as well as include actual consumer price index (CPI) for December 2019 and December 2020; and our final decision inflation forecast of 2.37 per cent to replace AusNet Services' inflation forecast of 2.45 per cent.

16.2.4.3 Metering revenue and charges

Capital expenditure

Our final decision allows for $83.39 million ($2020–21) in forecast capex for AusNet Services' 2021–26 regulatory control period, as opposed to $78.11 million ($2020–21) proposed by AusNet Services (see Table 16.11).

Table 16.11 Forecast capital expenditure ($2020–21)

Forecast Capex	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Proposal	14.72	12.47	11.79	12.63	13.44	65.05
Draft Decision	18.13	16.52	16.09	15.49	16.22	82.45
Revised Proposal	17.24	15.64	15.23	14.62	15.39	78.11
Final Decision	18.24	16.67	16.28	15.73	16.47	83.39

Source: AER, *Draft decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, September 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – Metering PTRM – FY22-26*, January 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – EDPR 2022-26 Revised proposal – PTRM model (2022–26)*, Dec 2020; AER, *Final decision AusNet – distribution determination 2021–26 – Metering PTRM*, April 2021

Our final decision forecast capex consists of:

- IT $5.48 million ($2020–21)

- Communications $35.77million ($2020–21)
- Metering capex (remotely read interval meters and transformers) $41.28 million ($2020–21)
- Leases capitalised $0.23 million ($2020–21)
- Equity raising costs $0.63million ($2020–21).

The key driver for our higher forecast capex than that proposed by AusNet Services is our decision to not accept AusNet Services' proposal to re-allocate 20 per cent of its mesh network asset maintenance capex to standard control services and instead to allocate 6 per cent to standard control services.

AMI IT and communication costs

Our final decision allows for forecast communication capex of $35.77 million ($2020–21). This is higher than AusNet Services' proposed communications capex of $30.98 million ($2020–21). The key driver of this of the increase in communications capex compared to AusNet Services revised proposal is our decision on cost allocation as discussed above (see section 16.2.4.1).

Forecast opex

Our final decision allows for $78.84 million ($2020–21) in forecast opex for AusNet Services' 2021–26 regulatory control period. This is higher than AusNet Services' proposed opex of $73.77 million ($2020–21), driven by our decision on cost allocation as set out above under section 16.2.4.1.

Table 16.12 provides the final decision forecast operating expenditure for the 2021–26 regulatory control period.

Table 16.12 Forecast operating expenditure ($2020–21)

Forecast Opex	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Proposal	11.11	11.36	11.48	11.43	11.48	56.86
Draft Decision	15.23	15.49	15.69	15.78	15.88	78.08
Revised Proposal	14.30	14.60	14.83	14.96	15.08	73.77
Final Decision	15.31	15.62	15.86	15.97	16.08	78.84

Source: AER, *Draft decision AusNet Services – distribution determination 2021–26 – Metering PTRM*, September 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – Metering PTRM – FY22-26*, January 2020; AusNet Services, *Electricity distribution price review 2022–26 – Supporting document – EDPR 2022-26 Revised proposal – PTRM model (2022–26)*, Dec 2020; AER, *Final decision AusNet – distribution determination 2021–26 – Metering PTRM,* April 2021

The key driver of the increase in opex compared to AusNet Services revised proposal is our decision on cost allocation as discussed above in section 16.2.4.1.

16.2.4.4 Meter exit fees

Our final decision sets metering exit fees that reflect adjustments we made to the building block components for type 5 and 6 (incl. smart metering) revenue. These metering exit fees reflect:

- apportionment of the meter, IT, communications, and any other regulated asset base to reflect foregone revenue based on the average remainder of life of an asset
- administration costs of removing the meter, and
- tax allowances, and other relevant costs.

These cost components are sourced from the calculations of the building block components for type 5 and 6 (incl. smart metering) revenue, and are therefore subject to the same assessment and reasoning as for the type 5 and 6 (incl. smart metering) revenue.

16.3 Public lighting services

Public lighting services are defined as the:

- operation, maintenance, repair and replacement of public lighting assets in line with the Public lighting Code or the relevant legislation
- alteration and relocation of public lighting assets, and
- provision of new public lights.

16.3.1 Final decision

Our final decision is to:

- Accept AusNet Services' co-funding proposal for its light-emitting diode (LED) bulk replacement program following its engagement with stakeholders.
- Accept AusNet Services updates in its public lighting model to correct for data inaccuracies included in its initial proposal.

In our final decision, we adjust AusNet Services public lighting model to derive charges for year one (2021–22) of the 2021–26 regulatory control period for:

- actual inflation where relevant
- our final decision on labour price growth, and
- our final decision WACC (see Attachment 3 – Rate of return).

Our final decision sets the public lighting prices for the first year (2021–22) of the 2021–26 regulatory control period which are set out in C   Public lighting services of this attachment. Prices for the subsequent years of the regulatory control period will be escalated by actual inflation and the X factors set out in Attachment 14 – Control mechanisms.

16.3.2 AusNet Services' revised proposal

In response to our draft decision, AusNet Services:

- proposed a co-funding arrangement with councils for a bulk replacement program to replace MV lights with efficient LED lights
- accepted our draft decision amendments to the public lighting model, except for labour price growth and the amendments to the T5 replacement and repair daily rates
- accepted our draft decision LED unit prices
- introduced three new public lighting prices for major road smart lighting.

AusNet Services also updated its public lighting model to correct for errors relating to:

- the double counting of public lights, and
- misallocation of public lights across councils.[71]

16.3.2.1 AusNet Services' bulk replacement program

As requested in our draft decision, AusNet Services have undertaken additional stakeholder consultation to discuss a program to replace MV lights with LED lights.[72] AusNet Services' noted its revised co-funding arrangement of LED bulk replacements reflects its stakeholder consultation, which better reflects the preferences of its public lighting customers.[73]

AusNet Services put to councils an option to replace all MV lights by 2026, with the cost partially funded by AusNet Services regulated capital expenditure.[74] This option would result in a moderate growth in the capital charges for lights in the efficient light class (LED, CFL, T5) for the following 20 years. AusNet Services noted this option:[75]

- Involves replacing MV lights with efficient LED lights, where AusNet Services would fully fund the replacement for 11 councils and co-fund the replacement for 18 councils by providing up to $45 per light in each council (where relevant). AusNet Services' $6.9 million in replacement costs would be derived from its efficient lighting regulated asset base and paid for by public lighting customers through public lighting tariffs. The 18 co-funded councils would fund $10.2 million of the remaining capital cost to ensure all MV lights are replaced.
- Provides equity for councils that have already invested in efficient lighting replacements and ensures the MV lights will be replaced. AusNet Services stated

71 AusNet Services, *Information request #097*, March 2021.

72 AER, *Draft Decision AusNet Services Distribution Determination 2021–26, Attachment 16 Alternative control services*, September 2020, p. 57.

73 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p.198.

74 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p.198.

75 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p.199.

where it determined a council has not substantially received the full value of their $45 per efficient light allocation, it will work with the council to fund the replacement of additional aged high pressure sodium lights in their area.

- Will give councils the opportunity to coordinate their lighting exchange program using AusNet Services' and the Municipal Association of Victoria's approved resources, including project manager and tendered service providers. Regional or smaller councils will be given the opportunity to work together with nearby councils and engage the same project manager and tendered service provider to organise a single program across municipalities.
- Is an approach to provide smart street lighting by creating new public lighting prices for major road smart lighting, with higher costs for software as a service and more expensive smart cells. This approach allows to offer IT systems and smart lighting services without increasing the prices for councils that have not invested in smart lighting. It contrasts with alternative approaches of not providing smart lighting services or providing smart lighting services to all customers with the higher costs of more expensive smart Photo Electric (PE) cells and IT systems. However, it means paying higher unit rates for smart PE cells due to lower volumes.

16.3.3 Assessment approach

To determine prices for public lighting services we assessed AusNet Services' public lighting model, considered historical data and benchmarked proposed costs against other NEM distributors and against independent data and information as relevant. Specifically, we assessed proposed labour rates, luminaire prices, other input assumptions and stakeholder submissions to derive proposed public lighting charges. We also updated model parameters where appropriate.

With regard to AusNet Services' proposed LED bulk replacement program, we engaged with the Local Government Response (LGR) (a group comprising Victorian greenhouse alliances, public lighting group and member councils) to discuss:

- AusNet Services' consultation with stakeholders on its revised co-funded bulk replacement program, and
- LGR's views on the revised bulk replacement program itself.

16.3.4 Reason for final decision

16.3.4.1 LED bulk replacement program

We accept AusNet Services co-funding proposal for its LED bulk replacement program. We acknowledge the work AusNet Services has done with stakeholders in working toward an accepted replacement program.

As noted, in our draft decision we did not accept AusNet Services' proposed LED replacement program because it was not supported by stakeholder feedback.[76] We requested AusNet Services to consult further with stakeholders to determine whether:[77]

- an alternative replacement program could be supported, or
- customers should instead work through any proposed bulk replacements on a case-by-case basis.

In response to our draft decision, AusNet Services engaged further with stakeholders to discuss key concerns raised in response to AusNet Services' initial proposal.[78] Through this engagement, AusNet Services proposed the amended co-funded bulk replacement program set out in section 16.3.2. AusNet Services stated that representative working groups provided in principle support of its proposed replacement program.[79]

In its submission, the LGR supported this position by noting AusNet Services proactively responded to the councils' request to find an alternate, collaborative approach to the replacement of lights.[80] The LGR noted the co-funding arrangement of the bulk replacement program was supported by the majority of councils although some councils were not in a position to commit to the co-funding arrangement at this stage.[81] These councils noted:

- that to comment to the co-funding arrangement a formal proposal would need to be submitted to their respective councils for consideration[82]
- their budgeting process does not allow for rapid consensus decision making, and[83]
- they will need to receive the co-funding proposals at least 8 months prior to the start of the financial year in which the upgrades will take place.[84]

LGR recommended AusNet Services bulk replacement program be accepted on the following basis:

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76 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.16-57.

77 AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.16-57.

78 AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p. 198.

79 AusNet Services, *Revised regulatory proposal 2022–26*, 3 December 2020, p. 200.

80 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 7.

81 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 7.

82 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 8.

83 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 9.

84 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 9.

- all the elements of the replacement program developed with the councils be included in the program roll-out
- future processes that propose such funding need longer time frames for engagement to ensure councils can adequately consider the proposals
- Councils cannot commit in advance to co-funding without going through proper process, AusNet Services will need to work with councils to ensure:[85]
    - there is sufficient time to consider the matter in the relevant year
    - an agreed process is determined if councils cannot allocate funding in the nominated year
    - cross subsidies are removed or diminished
    - a clear process for resolving lighting data inaccuracies before and during the project.

We engaged further with the LGR to discuss its submission and to get better insights into AusNet Services' proposed replacement program. Through this engagement, LGR reiterated its view that AusNet Services replacement program should be accepted by the AER.[86]

In response to the LGR's concerns regarding where a council cannot provide the funds to co-fund an LED bulk replacement, we note AusNet Services still has an obligation to ensure it is undertaking normal operation and maintenance requirements and should work with councils on how best to spend the allocated funds. AusNet Services may agree with a council to proceed with a portion of the planned bulk replacement on the basis that the funding has been provided.

We also note that our draft decision amended AusNet Services' LED unit rates to the most recent tender prices with respect to LED unit rates.[87] AusNet Services accepted our draft decision LED unit rates in its revised proposal.[88]

16.3.4.2 Correction of public lighting volumes

We accept AusNet Services update to its public lighting model to correct for errors relating to:

- the double counting of public lights, and
- misallocation of public lights across councils.

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[85] Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 9.

[86] AER File Note, *Meeting between AER Staff and the LGR*, February 2021.

[87] AER, *Draft Decision AusNet Services distribution determination 2021 to 2026 Attachment 16 Alternative Control Services*, September 2020, p.16-55.

[88] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p. 198.

These updates will ensure AusNet Services public lighting prices are more accurate and better reflect the costs in providing these services. Correcting for this error will result in an increase in per light prices of between 3 and 11 per cent for customers in the North East Region of AusNet Services network.

We note stakeholders submitted that where AusNet Services or councils uncover data inaccuracies or billing errors that these be resolved in a timely manner.[89] We consider in this instance AusNet Services has responded in a timely manner to correct for the error in its data management systems and proposed public lighting model.

Since submission of its initial proposal, AusNet Services became aware of a discrepancy between the number of public lights registered in its asset management system and those in its billing system for customers.[90] AusNet Services noted that around 18,000 lights in the North East Region in its asset management system had either been double counted or had been misallocated to the Central Region.[91]

In discussions with the AER, AusNet Services confirmed the error only impacted its internal systems and operations and no customers had been overcharged. AusNet Services charges customers based on its billing system which did not include these errors. If anything, AusNet Services had been under recovering due to these errors.[92]

AusNet Services also noted that through its engagement with councils following our draft decision they agreed to improve its public lighting data records.[93] AusNet Services noted that councils had been made aware of data issues and that it would be updating its public lighting model in its revised proposal. Further, AusNet Services noted that it would work with councils to correct data issues when identified.

We consider AusNet Services has been transparent in its approach to correct for its volume data error and updates to its public lighting model. We acknowledge the work AusNet Services is undertaking to improve the quality of its public lighting data. AusNet Services has noted that it is currently improving its processes to ensure its data will become increasingly more accurate and be more transparent to councils.

16.3.4.3 Other public lighting prices

We accept AusNet Services revised T5 replacement and repair daily rates to be consistent with Powercor's rates, as per the approach set out in our draft decision.

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89 Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 9.

90 AER File note, *Meeting between AER staff and AusNet Services*, 23 March 2021.

91 AusNet Services, *Information request #096*, March 2021.

92 AusNet Services, *Information request #096*, March 2021.

93 AusNet Services, *Information request #096*, March 2021.

The LGR raised concerns regarding the inconsistency on VLED daily repairs between AusNet Services and Powercor given they are two similarly configured distribution networks.[94] The LGR should now be satisfied the daily repair rates are now consistent.

We consider our benchmarking and comparative analysis can enable distributors to improve performance and pass on the benefits to customers. However, we also note that elements such geographical parameters, cost structures and external contractors rates can influence the input assumptions for different distributors.

We also accept the AusNet Services introduction of three new ‘smart’ lights into its price list that received in principle support from stakeholders.[95] [96]

16.3.4.4 Price movements

Our final decision results price movements for the first year of the regulatory control period are in the range of 1.2 per cent increase to a decrease of 8 per cent for some of the light types when compared to the revised proposal. Overall the revenue increase for the 2021–26 regulatory control period is driven by adjustments to the light volumes and deployment of bulk replacement program and is in a reasonable range.

Our final decision public lighting prices and the corresponding X factors are set out in C Public lighting services of this attachment.

[94] Local Government Response, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26,* December 2020, p. 7.

[95] AusNet Services, *Revised regulatory proposal 2022–26*, December 2020, p. 198.

[96] AER File Note, Meeting between AER Staff and the LGR, 8 February 2021.

A Ancillary network services prices

Prices in this appendix are in $2021–22.

Table 16.13 Fee-based ancillary network services prices for 2021–22 ($2021–22), final decision – business hours

Service description	AER final decision
Connection-related	
Single Phase overhead	$498.35
Single Phase underground	$219.01
Single Phase underground with a directly connected meter on group metering panel	$472.23
Multi-phase overhead with a directly connected meter	$566.34
Multi-phase overhead with a CT connected meter	$1,081.27
Multi-phase underground with a directly connected meter	$347.11
Multi-phase underground with a directly connected meter on group metering panel	$604.57
Multi-phase underground with a CT connected meter	$862.04
95mm2 overhead service from LVABC	$852.49
Establish temporary supply connection	$494.11
Appointment – inspection of group or CT metering prior to connection	$514.93
Service truck – Disconnect / Reconnect at pole or pit	$567.41
Other	
Meter equipment test[1]	$311.67
Meter equipment test – Each Additional Meter at same site[1]	$71.86
Wasted Truck Visit – customer not ready for their requested works	$211.04
Manual assessment of PV & small generator installation enquiry, 4.6kW to 15kW	$325.79
Manual assessment of PV & small generator installation enquiry, 15kW to 30kW	$325.79
Security and watchmen lights	$60.88
Auxiliary metering services	
Remote special meter read	$0.00
Remote re-energisation	$0.00
Remote de-energisation	$0.00
Remote meter re-configuration	$15.11

Service description	AER final decision
Field officer visit	$34.80
Manual meter reading	$34.80
Priority re-energisation	$33.69
Non-standard AMI data subscription (per month)	$0.85 (for compliance purposes only)[2]
Type 7 metering charge	
Per NMI	$30.00
Per light	$1.76

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Ancillary Network Services Model*, April 2021; AER, *Final decision – AusNet Services distribution determination – 2021–26 – Auxiliary Metering Services Charges Model*, April 2021

Notes: 1. This table reflects the simplification of AusNet Services' meter equipment tests. For a more detailed discussion, see section 16.1.4.1.

2. As discussed in section 16.1.4.5 of the draft decision, this price is included for the purposes of complying with the price cap formula only. AusNet Services does not propose to offer this service in the 2021–22 regulatory year.

Table 16.14 Fee-based ancillary network services prices for 2021–22 ($2021–22), final decision – after hours

Service description	AER final decision
Connection-related	
Single Phase overhead	$872.12
Single Phase underground	$383.27
Multi-phase overhead with a directly connected meter	$991.10
Multi-phase overhead with a CT connected meter	$1,822.22
Multi-phase underground with a directly connected meter	$1,307.29
Multi-phase underground with a CT connected meter	$1,508.57
95mm2 overhead service from LVABC	$1,491.86
Establish temporary supply connection	$864.69
Auxiliary metering services	
Field officer visit	$60.91

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Ancillary Network Services Model*, April 2021.

Table 16.15 Non-exhaustive list of ancillary network services provided on a quotation basis, draft decision

Description of service
Access permits, oversight and facilitation
Network related property services
Notices of arrangement and completion notices
Network safety services
Connection application and management services
Community network upgrades
Provision of training to third parties for network related access
Authorisation and approval of third party service providers design, work and materials
Customer initiated network asset relocations
Customer requested supply outage
Customer requested provision of electricity network data
Enhanced connection services

Source: AusNet Services, *Electricity Distribution Price Review 2022–26: Part IV*, 31 January 2020, pp. 53–56.

Table 16.16 Quoted service hourly labour rates for 2020–21, final decision ($2021–22)

Service description	AER labour type	AER final decision maximum total hourly rate – business hours	AER final decision maximum total hourly rate – after hours
Construction Overhead Install	Field worker	$121.21	$147.21
Construction Underground Install	Field worker	$118.39	$143.78
Construction Substation Install	Field worker	$118.39	$143.78
Electrical Tester Including Vehicle & Equipment	Technical specialist	$174.55	$238.63
Planner Including Vehicle	Technical specialist	$162.72	NA
Supervisor Including Vehicle	Technical specialist	$162.72	NA
Design	Engineer	$138.93	$168.73
Drafting	Technical specialist	$106.76	$129.66

Service description	AER labour type	AER final decision maximum total hourly rate – business hours	AER final decision maximum total hourly rate – after hours
Survey	Technical specialist	$125.76	$152.74
Tech Officer	Technical specialist	$125.76	$152.74
Line Inspector	Technical specialist	$121.21	$147.21
Contract Supervision	Technical specialist	$125.76	$152.74
Protection Engineer	Engineer	$138.93	$168.73
Maintenance Planner	Technical specialist	$125.76	$152.74
Senior Engineer	Senior engineer	$200.26	$299.02

Source: Marsden Jacob, *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services: Advice to the Australian Energy Regulator*, 30 June 2020, p. 10; AER, *Final decision – AusNet Services distribution determination – 2021–26 – Ancillary Network Services Model*, April 2021.

Table 16.17 AER draft decision on X factors for each year of the 2021–26 regulatory control period for ancillary network services (per cent)

	2022–23	2023–24	2024–25	2025–26
X factor	-0.6627	-0.6091	-0.7328	-0.9509

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Ancillary Network Services Model*, April 2021

Note: We do not apply an X factor for 2021–22 because we set the 2021–22 ancillary network service prices in this determination.

To be clear, the labour price growth forecasts in this table are operating as de facto X factors. Therefore, positive labour price growth forecasts are represented as negative in this table and vice versa.

B Type 5 and 6 (incl. smart metering) metering exit fees

Prices in this appendix are in $2021–22.

Table 16.18 AER final decision metering exit fees ($2021–22)

Meter type	2021–22
Single phase single element	$364.37
Single phase two element with contactor	$361.32
Multiphase	$363.04
Multiphase with contactor	$363.04
Multiphase CT connected	$363.21

Source: AER, *Final decision – AusNet Services distribution determination 2021–26 – Metering PTRM*, April 2021.

Table 16.19 AER final decision on X factors for each year of the 2021–26 regulatory control period for metering exit fees (per cent)

X factor	2022–23	2023–24	2024–25	2025–26
Single phase single element	6.0984	7.1493	8.1869	9.1412
Single phase two element with contactor	6.0244	7.0769	8.1142	8.5921
Multiphase	6.0615	7.1142	8.1526	8.9133
Multiphase with contactor	6.0615	7.1142	8.1526	8.9133
Multiphase CT connected	6.0675	7.1182	8.1557	8.9431

Source: AER, *Final decision – AusNet Services distribution determination 2021–26 – Metering PTRM*, April 2021.

C Public lighting services

Prices in this appendix are in $2021–22.

Table 16.20 Final decision public lighting prices ($2021–22)

AusNet Services' Lights (Central)	Revised Proposal	Final Decision
Mercury Vapour 80W	$60.14	$60.88
HP Sodium 150W	$112.16	$112.86
HP Sodium 250W	$115.00	$115.69
Mercury Vapour 50W	$92.01	$93.15
Mercury Vapour 125W	$88.40	$89.50
Mercury Vapour 250W	$120.75	$121.47
Mercury Vapour 400W	$125.35	$126.10
HP Sodium 100W	$120.01	$120.77
HP Sodium 400W	$163.30	$164.27
Metal Halide 70W	$262.50	$265.76
Metal Halide 100W	$267.79	$269.49
Metal Halide 150W	$304.23	$306.16
HP Sodium 50W	$49.72	$50.04
T5 2X14W	$51.50	$51.71
T5 2X24W	$55.01	$55.22
LED 18W	$29.24	$29.46
LED non-standard low power ~14W	$31.07	$31.28
LED 70W-125W (L1)	$48.63	$45.36
LED 155W-250W (L2)	$49.27	$46.04
LED 275W-400W (L4)	$55.00	$52.06
Compact Fluorescent 32W	$45.30	$45.49
Compact Fluorescent 42W	$45.30	$45.49
Smart lighting L1	$59.59	$59.98
Smart lighting L2	$60.23	$60.65
Smart lighting L4	$65.96	$66.68

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Public Lighting Model*, April 2021.

AusNet Services' Lights (North East)	Revised Proposal	Final Decision
Mercury Vapour 80W	$66.12	$66.94
HP Sodium 150W	$131.45	$132.16
HP Sodium 250W	$131.25	$131.93
Mercury Vapour 50W	$$97.86	$99.07
Mercury Vapour 125W	$$97.86	$99.07
Mercury Vapour 250W	$136.50	$137.21
Mercury Vapour 400W	$140.44	$141.16
HP Sodium 100W	$140.66	$141.41
HP Sodium 400W	$186.38	$187.34
Metal Halide 70W	$251.55	$254.65
Metal Halide 100W	$278.43	$279.91
Metal Halide 150W	$316.32	$318.01
HP Sodium 50W	$59.78	$60.10
T5 2X14W	$57.37	$57.56
T5 2X24W	$61.43	$61.62
LED 18W	$31.37	$31.58
LED non-standard low power ~14W	$33.12	$33.33
LED 70W-125W (L1)	$56.19	$51.24
LED 155W-250W (L2)	$56.83	$51.91
LED 275W-400W (L4)	$62.55	$57.94
Compact Fluorescent 32W	$50.46	$50.63
Compact Fluorescent 42W	$50.46	$50.63
Smart lighting L1	$67.46	$67.82
Smart lighting L2	$68.10	$68.49
Smart lighting L4	$73.82	$74.52

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Public Lighting Model*, April 2021.

Table 16.21 Final decision public lighting – X factors (per cent)

AusNet Services' Lights (Central)	2022–23	2023–24	2024–25	2025–26
Mercury Vapour 80W	0.0818	-2.4754	-6.5005	0.2455
HP Sodium 150W	-0.0978	-0.4618	-4.2807	-0.1092
HP Sodium 250W	-0.0894	-0.5942	-4.2705	-0.0999
Mercury Vapour 50W	0.0818	-2.4754	-6.5005	0.2455
Mercury Vapour 125W	0.0818	-2.4754	-6.5005	0.2455
Mercury Vapour 250W	-0.0894	-0.5942	-4.2705	-0.0999
Mercury Vapour 400W	-0.0894	-0.5942	-4.2705	-0.0999
HP Sodium 100W	-0.0978	-0.4618	-4.2807	-0.1092
HP Sodium 400W	-0.0894	-0.5942	-4.2705	-0.0999
Metal Halide 70W	0.0818	-2.4754	-6.5005	0.2455
Metal Halide 100W	-0.0978	-0.4618	-4.2807	-0.1092
Metal Halide 150W	-0.0978	-0.4618	-4.2807	-0.1092
HP Sodium 50W	-0.0978	-0.4618	-4.2807	-0.1092
T5 2X14W	-3.6758	-2.7277	-2.1625	-1.3291
T5 2X24W	-3.5424	-2.6354	-2.0970	-1.3032
LED 18W	-5.0645	-3.6723	-2.8278	-1.5879
LED non-standard low power ~14W	-4.7904	-3.4858	-2.6962	-1.5309
LED 70W-125W (L1)	-5.9329	-4.2848	-3.2511	-1.8244
LED 155W-250W (L2)	-6.1597	-4.4377	-3.3542	-1.8686
LED 275W-400W (L4)	-7.9290	-5.6089	-4.1338	-2.1998
Compact Fluorescent 32W	-3.6758	-2.7277	-2.1625	-1.3291
Compact Fluorescent 42W	-3.6758	-2.7277	-2.1625	-1.3291
Smart lighting L1	-4.5210	-3.3145	-2.5507	-1.4661
Smart lighting L2	-4.7088	-3.4446	-2.6406	-1.5061
Smart lighting L4	-6.2214	-4.4763	-3.3459	-1.8166

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Public Lighting Model*, April 2021.

AusNet Services’ Lights (North East)	2022–23	2023–24	2024–25	2025–26
Mercury Vapour 80W	0.1262	1.0727	-6.1418	0.2089
HP Sodium 150W	-0.1274	1.0858	-3.7959	-0.1987
HP Sodium 250W	-0.1869	0.7374	-3.8469	-0.1611
Mercury Vapour 50W	0.1262	1.0727	-6.1418	0.2089
Mercury Vapour 125W	0.1262	1.0727	-6.1418	0.2089
Mercury Vapour 250W	-0.1869	0.7374	-3.8469	-0.1611
Mercury Vapour 400W	-0.1869	0.7374	-3.8469	-0.1611
HP Sodium 100W	-0.1274	1.0858	-3.7959	-0.1987
HP Sodium 400W	-0.1869	0.7374	-3.8469	-0.1611
Metal Halide 70W	0.1262	1.0727	-6.1418	0.2089
Metal Halide 100W	-0.1274	1.0858	-3.7959	-0.1987
Metal Halide 150W	-0.1274	1.0858	-3.7959	-0.1987
HP Sodium 50W	-0.1274	1.0858	-3.7959	-0.1987
T5 2X14W	-3.3271	-2.4803	-1.9859	-1.2501
T5 2X24W	-3.2010	-2.3927	-1.9236	-1.2255
LED 18W	-4.7207	-3.4325	-2.6591	-1.5110
LED non-standard low power ~14W	-4.4905	-3.2750	-2.5471	-1.4618
LED 70W-125W (L1)	-5.2868	-3.8461	-2.9494	-1.6957
LED 155W-250W (L2)	-5.4962	-3.9891	-3.0467	-1.7376
LED 275W-400W (L4)	-7.1551	-5.1020	-3.7949	-2.0574
Compact Fluorescent 32W	-3.3271	-2.4803	-1.9859	-1.2501
Compact Fluorescent 42W	-3.3271	-2.4803	-1.9859	-1.2501
Smart lighting L1	-4.0361	-2.9780	-2.3180	-1.3716
Smart lighting L2	-4.2072	-3.0976	-2.4012	-1.4086
Smart lighting L4	-5.6011	-4.0585	-3.0628	-1.7004

Source: AER, *Final decision – AusNet Services distribution determination – 2021–26 – Public Lighting Model*, April 2021.

Shortened forms

Shortened form	Extended form
ACS	alternative control services
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	advanced metering infrastructure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
CPI	consumer price index
Distributor	distribution network service provider
ECA	Energy Consumers Australia
F&A	framework and approach
LED	light-emitting diode
MV	mercury vapour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RIN	regulatory information notice
SCS	standard control services
WACC	weighted average cost of capital

FINAL DECISION

AusNet Services Distribution Determination 2021 to 2026

Attachment 18 Connection policy

April 2021

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

18 Connection policy

We are required to make a decision on the connection policy that is to apply to AusNet Services for the 2021–26 regulatory control period. This may be the connection policy prepared by a distributor, some variant of it, or a policy substituted by the AER.[1]

A connection policy sets out the nature of connection services offered by a distributor, when connection charges may be payable by retail customers and how those charges are calculated. It also:

- must be consistent with:[2]
    - the connection charge principles set out in chapter 5A of the National Electricity Rules (NER)
    - the connection policy requirements set out in part DA of chapter 6 of the NER
    - our connection charge guidelines published under chapter 5A,[3] and,
- must specify:[4]
    - the categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed
    - the aspects of a connection service for which a connection charge may be made
    - the basis on which connection charges are determined
    - the manner in which connection charges are to be paid (or equivalent consideration is to be given)
    - a threshold (based on capacity or any other measure identified in the connection charge guidelines) below which a retail customer (not being a non-registered embedded generator or real estate developer) will not be liable for a connection charge for an augmentation other than an extension.

The AER's connection charge guidelines for electricity retail customers

A connection policy must be consistent with our connection charge guidelines for electricity retail customers. The purpose of our guideline is to ensure that connection charges:[5]

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1 NER, cl 6.12.1(21).

2 NER, cl 6.7A.1(b)(1).

3 AER, *Connection charge guideline for electricity retail customers, Under chapter 5A of the National Electricity Rules Version 1.0*, June 2012.

4 NER, cl 6.7A.1(b)(2).

5 NER, cl 5A.E.3(b); AER, *Connection charge guideline for electricity retail customers, Under chapter 5A of the National Electricity Rules Version 1.0*, June 2012, p. 11.

- are reasonable, taking into account the efficient costs of providing the connection services arising from the new connection or connection alteration
- provide, without undue administrative cost, a user-pays signal to reflect the efficient costs of providing the connection services
- limit cross-subsidisation of connection costs between different classes (or subclasses) of retail customers
- are competitively neutral, if the connection services are contestable.

18.1 Final decision

We have taken into account AusNet Services' revised revenue proposal, submissions raised by stakeholders and our draft decision in reaching our final decision. Our final decision is to apply a variant of the connection policy proposed by AusNet Services for the 2021–26 regulatory control period, specifically regarding its proposed threshold level for where upstream augmentation charges will apply, because parts of its revised connection policy are not consistent with:

- our connection charge guidelines for electricity retail customers under chapter 5A.
- the threshold levels of all other jurisdictions of the national electricity market (NEM).

The reasons for the above rejection and the variations that we have made are explained in section 18.5. Our approved connection policy can be found in appendix A to this attachment.

18.2 AusNet Services’ revised proposal

In the revised proposal AusNet Services accepted the majority of our proposed changes in the draft decision to its original connection policy. However, it submitted the following contentions:[6]

- It has not updated the augmentation threshold of 10 kilovolt amperes (kVA) on single-wire earth return (SWER) lines. This change would enable customers to upgrade existing distribution transformers at no cost and therefore increase cross-subsidisation.
- It has not accepted our change that the augmentation threshold for new connections other than on SWER lines to 100 amperes (A) per phase for multiphase connections.

AusNet Services also proposed the following additions to the original connection policy:

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6 AusNet Services, *Electricity Distribution Price Review 2021–26 Revised Regulatory Proposal*, December 2020, p.168.

- amendments to the upstream augmentation rates to better reflect the cost of extending high voltage (HV) feeders connected to Rapid Earth Fault Current Limiter (REFCL) feeders.
- a change to ensure that embedded generators pay the tax costs associated with their connection, so that other customers do not unfairly incur these costs.
- including the company tax liability arising from customer contributions received from works under Alternative Control Services.

18.3 Submissions

The Consumer Challenge Panel, sub-panel 17 (CCP17) supported AusNet Services' actions outlined in section 11.1 of the revised proposal, including SWER connections augmentation threshold to 10kVA, and updating cost recovery for REFCL feeders.[7]

18.4 Assessment approach

We examined the revised connection policy against the requirements of Part DA of chapter 6 as stated above—whether it:

- is consistent with the connection charge principles set out in chapter 5A of the NER, and our connection charge guidelines
- contains all the information for new customers as prescribed by the NER.

In addition, we also examined whether:

- other connection related charges included in the connection policy, such as metering installation charges, are consistent with the service classification of this final determination.
- the connection policy contains terms that are not fair and reasonable.

18.5 Reasons for final decision

18.5.1 Including the net tax liability arising from capital contribution from large embedded generators

In its revised proposal, AusNet Services submitted that:[8]

- This change will reduce the cross-subsidy paid by our customers to large embedded generator connections and to maintain competitive neutrality between generators connecting to the transmission and distribution networks.
- As generators connecting to the transmission network contribute to the economic tax cost borne by the transmission network service providers on the capital portion

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[7] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 96.

[8] AusNet Services*, Electricity Distribution Price Review 2022-26 Revised Regulatory Proposal*, December 2020, p.170.

of their connection, applying the same charges to distribution-connected generators achieves parity in this respect.

- These connections are bespoke and generally only benefit the individual application.
- The wider customer base currently pays the tax costs associated with these connections. This is a cross-subsidy that it does not believe is well-understood nor intended.
- Both AusNet Services and its customers are exposed to forecasting risk regarding these connections. That is, if the forecast is too high, a higher amount of tax contribution will be paid by customers than is required. If the forecast is too low, the distributor will bear tax costs for which it will not be compensated.
- There is a high degree of uncertainty over the volume of these connections. These are very lumpy and heavily influenced by Government policy support for renewable generation in Victoria which contributes to the uncertainty around these forecasts.

In response to our information request, AusNet Services further advised that:[9]

> It consulted on this proposed approach to the tax treatment of capital contributions for large embedded generators as part of its Revised Proposal engagement program. This comprised several sessions attended by a range of stakeholders (including the AER, Vic Government, a range of customer advocates, the Customer Forum, its internal Customer Consultative Committee (CCC) and new energy service providers) and its intention to directly charge embedded generators the tax cost associated with their connection, removing the current cross subsidy, was described in detail.

We accept the AusNet Services revised proposal to charge the net tax liability (netting off future depreciation reverse cash flow) arising from the capital contribution of embedded generators larger than 1.5 MW. This is on the basis that:

- AusNet Services has consulted with relevant stakeholders on the proposal
- the tax liability is part of the cost incurred by AusNet Service for such new connections
- the process will align the connection cost structure with transmission connected generators
- the CCP17 supported the change
- if the tax liability is not included in the capital contribution calculation of these embedded generators, this cost will be paid by the entire customer base, rather than the beneficiary of the connection .

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9 AusNet Services, *Information Request 094*, March 2021.

However, an important principle is that distributors do not ‘double-dip’ or recover this tax cost (or any other costs) through different revenue mechanisms. This is clear from the connection charge principle that a capital contribution may only be required if the provision for the costs has not already been made through the existing distribution use of system (DUoS) charges or an applicable tariff. It is therefore important that this tax component must not be included in the post-tax revenue model to avoid double recovery.

18.5.2 Including the net tax liability arising from capital contribution from works under Alternative Control Services

Our decision is to reject this change, because the control mechanism set out in the Framework and Approach (F&A) does not allow this charging method. As explained in the draft decision for similar charging method proposed in AusNet Services’ initial regulatory proposed, tax components cannot be part of the charges under Alternative Control Services, because:[10]

> …the limitations set out in the NER on changes to control mechanism formulae following publication of the relevant F&A as being designed to limit the ability to make amendments after this point.

18.5.3 Change in service classification for connection of large embedded generators

AusNet Services also proposed to reclassify the connection of large embedded generators from standard control service to alternate control service.[11] We do not agree to this proposed change. Our reason for not agreeing to this change is discussed in attachment 13 – Classification of services.

18.5.4 Threshold for capital contribution for network extension or shared network augmentation.

AusNet Services sought to retain its proposal in the initial connection policy to set the threshold for:[12]

- SWER connections at 10 kVA
- all other connections at 100A in aggregate across all phases, for example 100A single phase or 33A 3-phase supply, because this level is consistent with the

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10 AER, *Draft Decision, AusNet Services, CitiPower, Jemena, Powercor, and United Energy Distribution Determination 2021 to 2026, Attachment 14 - Control mechanisms*, September 2020, p.11–35.

11 AusNet Services, *Electricity Distribution Price Review 2022–26 Revised Regulatory Proposal*, 3 December 2020 p.170.

12 AusNet Services, *Electricity Distribution Price Review 2022–26 Revised Regulatory Proposal*, 3 December 2020 p.169.

deemed standard connection agreement set out by the Essential Services Commission of Victoria (ESCV) in 2018.

Regarding the first matter, we have already approved the 10 kVA threshold for SWER connections in the draft decision. Hence, there will be no further changes.

With respect to the second matter, we rejected the originally proposed threshold in the draft decision. We amended the threshold level to 100A 3 phase (meaning 100A per phase or 70 kVA).

For the final decision, we maintain that AusNet Services' upstream charge threshold be amended to 100A per each of the three-phase supply, because:

- The proposed 100A in total threshold is the default capacity availability specified by the ESCV.[13] It is about the minimum capacity entitlements by all customers in Victoria; rather than a delineation line on who should contribute to upstream cost when a new small customer is seeking connection, as contemplated by the NER.
- The threshold value recommended in our connection charge guideline (at 100A three-phase) is consistent with Victorian distributors' tariff proposals that set the threshold for residential and small commercial customers at consuming up to 160 MWh per annum.[14]
- A 100A three-phase connection can consume 160 MWh of energy only if it operated at full power for 6.4 hours a day every day of the year. Hence, this threshold is consistent with the threshold for small connection expressed in the distributor's tariff proposal.
- This threshold is being applied to all other distributors in the NEM.

We maintain that AusNet Services' upstream charge threshold be amended to 100A 3 phase or 100A per each of the three-phases of a three phase supply.

18.6 Upstream charge rates

In the draft decision we benchmarked AusNet Services' proposed upstream augmentation unit rates in Table 2-4 (of the proposed connection policy) against its historical cost.

18.6.1 Comparison with historical cost

We calculated that AusNet Services' historical average overall network cost at low voltage level to be about $5,481.48 per kVA based on its latest Economic

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13 Essential Services Commission, *Decision: Deemed distribution contract variations: AusNet Services, CitiPower, Powercor, United Energy and Jemena*, April 2018, p10.

14 AusNet Services, *Revised Tariff Structure Statement 2022–26,* December 2020; Jemena, *Att 12-01 Tariff Structure Statement for 1 July 2021 to 30 June 2026,* December 2020; CitiPower, *APP06 - Tariff Structure Statement 2021–26*, December 2020; Powercor, *APP06 - Tariff Structure Statement 2026–26,* December 2020; United Energy, *APP06 – Tariff Structure Statement 2021–26,* December 2020.

Benchmarking Regulatory Information Notices report for 2018–19.[15] This represents a charging rate of $4,056 and $2,686 per kVA for residential and non-residential customers connecting at the low voltage networks respectively. This historical cost is higher than AusNet Services' proposed charge rates for shared network augmentation for low voltage networks at $1,191.75 and $872.60 for residential and non-residential customers respectively.

18.6.2 Our conclusion on the proposed upstream cost based on the above comparisons

In AusNet Services' revised proposal new rates were presented. AusNet Services proposed a revision to its augmentation unit rates to revise down the unit rates for non-REFCL connected customers and a new set of unit rates for REFCL connected customers. The new rates under each of the classifications were lower than the amounts we accepted in our draft decision.

We conclude that AusNet services' proposed marginal cost for shared network augmentation is reasonable because the rate is less than the actual historical cost, which is a good representation of the long run marginal cost.

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15 AusNet Services, *Economic Benchmarking RIN*, July 2019.

Shortened forms

Shortened form	Extended form
AER	Australian Energy Regulator
CCP17	Consumer Challenge Panel, sub-panel 17
distributor	distribution network service provider
DUoS	distribution use of system
ESCV	Essential Services Commission of Victoria
F&A	framework and approach
NEM	National Electricity Market
NER	National Electricity Rules
REFCL	Rapid Earth Fault Current Limiter
SWER	single-wire earth return

A AER approved connection policy for AusNet Services

AusNet services

AER modified version

Distribution Connection Policy

Effective from 1 July 2021

PUBLIC

mission zero

About AusNet Services

AusNet Services is a major energy network business that owns and operates key regulated electricity transmission and electricity and gas distribution assets located in Victoria, Australia. These assets include:

- A 6,574 kilometre electricity transmission network that services all electricity consumers across Victoria;
- An electricity distribution network delivering electricity to approximately 660,000 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 572,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

AusNet Services' purpose is 'to provide our customers with superior network and energy solutions.' The AusNet Services company values are:

- We work safely
- We do what's right
- We're one team
- We deliver

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.

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[redacted]

Table of contents

1 Introduction

1.1 Purpose of this document

This document is our connection policy for our electricity distribution network. It has been developed in accordance with the requirements of the National Electricity Rules (NER) and the connection charge guidelines[1] published by the Australian Energy Regulator (AER).

This Connection Policy sets out the circumstances where we a retail customer or real estate developer may be required to pay a connection charge for the provision of a connection service.[2] It specifies:

- The categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed;
- The aspects of a connection service for which a charge may be made;
- The basis on which connection charges are determined;
- The way connection charges are to be paid (or equivalent consideration is to be given); and
- The threshold below which a retail customer (not being a non-registered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation.[3]

1.2 Commencement date

This Connection Policy applies from 1 July 2021 and supersedes the previous version published on 28 July 2018.

1.3 Chapter 5A

The NER establishes two connection regimes:

- Chapter 5 of the NER creates a framework for connecting load for a registered or intending market participant, and connecting generation or large embedded generators which exceed the exemption limit (currently 5 MW) for registration as a participant with the Australian Energy Market Operator (AEMO).
- The regime in Chapter 5A applies to connecting load for retail customers, or a retailer or other person on behalf of a retail customer, or a real estate developer. It also applies to non-registered embedded generators and micro embedded generators (that is, embedded generator connections that comply with Australian Standard AS4777).

The Chapter 5A connection process is shorter and more flexible than the Chapter 5 process. This Connection Policy applies only to Chapter 5A connections.

1.4 Other relevant documents

This Connection Policy should be read in conjunction with the following documents:

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1 AER, Connection Charge Guidelines for Electricity Retail Customers under Chapter 5A of the National Electricity Rules, Version 1.0, June 2012.

2 In accordance with Clause 6.7A.1 of the NER.

3 A customer would be required to pay for an extension, where the customer is located outside the present boundaries of the distribution network.

- Our approved Annual Pricing Proposal, which sets out the fees for connection services and ancillary network services.
- Our minimum system requirements for inverter systems, including photovoltaic installations.
- The Model Standing Offer (MSO) for basic connection services, which sets out the terms and conditions for providing a connection between the distribution system and a retail customer's premises.
- The MSO for basic connection services (Basic Micro Embedded Generation), which sets out the terms and conditions for connecting a retail customer who is a micro embedded generator.
- The MSO for standard connection services, which sets out the terms and conditions for underground extension connection services within a specified distance from the distribution network.
- The electricity distribution contract, which sets out the terms and conditions on which we will maintain the connection.

These documents are available at:

- https://www.ausnetservices.com.au/en/New-Connections/Electricity-Connections; and
- https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-policies-and-manuals/deemed-distribution-contract-variations-review-2018#tabs-container2

1.5 Structure of this document

The remainder of this document is structured as follows:

- Section 2 provides an overview of the connection charging principles.
- Section 3 explains the charging arrangements for basic connections.
- Section 4 explains the charging arrangements for standard connections.
- Section 5 describes the arrangements for negotiated connections for small customers.
- Section 6 sets out the connection charging arrangements applying to real estate developers.
- Section 7 addresses other matters relevant to a connection, including security deposits and fees, payment of connection charges, and dispute resolution.

2 General connection pricing principles

2.1 Overview of connection services

Distribution connection services encompass the services required to connect premises to our distribution network. The connection services generally include the design, construction and energisation of connection assets.

In some circumstances, the new connection or connection alteration may require augmentation of the shared distribution network to ensure sufficient capacity to service the connection. The new connection or connection alteration may also require a network extension to enable the connection of the standard service line to the distribution network.

The following diagrams illustrate the typical connections for a residential customer for overhead and underground supply.

Figure 1: Typical overhead connection for residential customer

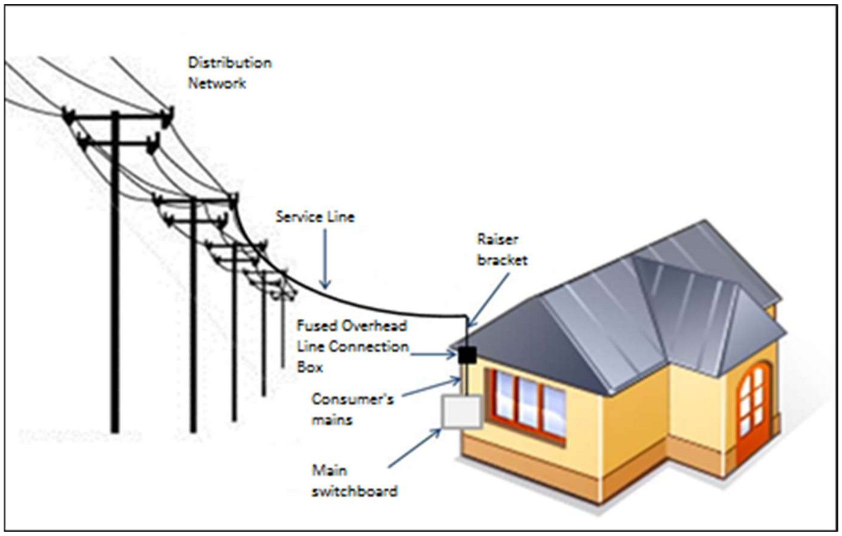
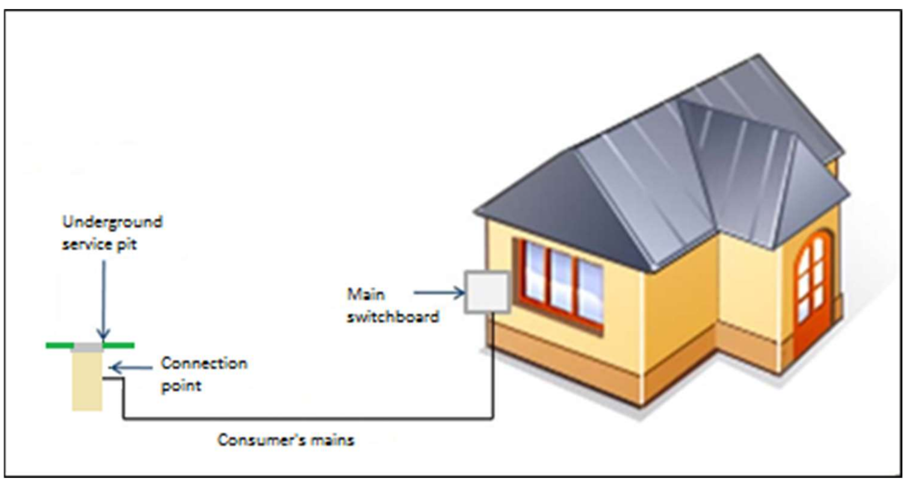


Figure 2: Typical underground connection for residential customer



There are different types of connection services, depending on:

- The customer classification of the applicant for the purposes of connection charging;
- The nature of the connection; and
- Whether line capacity is readily available in the existing distribution network.

The following sections detail the customer classifications, the classification of connection services and the connection charges that may be applicable.

2.2 Classification of customers

In broad terms, the connection service requirements and the associated charges will depend on the type of customer and the nature and location of the connection service. For this Connection Policy, it is useful to identify the different classes of customers:

- Residential and small commercial premises not requiring any network augmentation;
- Customer connections requiring network augmentation;
- Customers requesting temporary supply;
- Customers requesting an unmetered supply;
- Micro embedded generators;
- Embedded generators, other than micro embedded generation;
- Real estate developers; and
- Rapid Earth Fault Current Limiters (REFCL) HV customers.

Within these customer classes, we distinguish between customers on the basis of their network requirements, including:

- Energy consumption;
- Maximum demand; and
- Electricity import and export capacity.

The connection application process and the contractual arrangements vary accordingly.

2.3 Basic, standard and negotiated connection services

When an application is made for a new connection or alteration to an existing connection, we will offer:

- A basic connection service; or
- A standard connection service; or
- A negotiated connection service.

The type of connection service we offer will depend on the nature of the connection required and the network capacity available.

The table below sets out where in this document each type of connection is explained in detail. For connection types where one or more of the basic, standard or negotiated connections are available, the choice of service will often depend on the customer's particular circumstances.

Table 2-1: Further information for each type of connection

A connection for …	… is covered in …		
	Basic connection	Standard connection	Negotiated connection
Residential and small business overhead	Section 3	Section 4	Section 5
Residential and small business underground	Section 3	Section 4	Section 5
Micro embedded generation	Section 3	n/a	Section 5
Temporary connection	Section 3	n/a	Section 5
Unmetered supply	n/a	n/a	Section 5
Customer connections requiring augmentation	n/a	n/a	Section 5
Embedded generation connections	n/a	n/a	Section 5
Real estate developments	n/a	n/a	Section 5

2.3.1 Basic connection service

As the name suggests, the basic connection service is the most straightforward connection and will apply in most cases. If a property is eligible for a basic connection, all a customer is required to do is contact their chosen electricity retailer to request the connection and provide the necessary paperwork from their registered electrical contractor (electrician).

We offer two classes of basic connection service:

- A basic connection service, where connection between the distribution system and the customer's premises requires minimal or no augmentation of the distribution network.
- A basic micro embedded generation connection service, which is for the connection of micro embedded generators with a maximum capacity less than 5 kVA per phase, or more than 3.5 kVA if connected to a single-wire earth return (SWER) powerline.

A retail customer is only eligible for a basic connection service if the proposed connection satisfies certain conditions. These conditions are described in Chapter 3 of this Connection Policy and in the relevant Model Standing Offer (MSO). If a retail customer is not eligible for a basic connection service or prefers to negotiate the terms and conditions of the connection service, we will offer a negotiated connection service.

2.3.2 Standard connection service

We offer a standard connection service for underground connections within a specified distance from the distribution network, as set out in section 4.2 of this Connection Policy and Table 4-1. This service includes trenching and boring under roads, if required. Underground connections that require longer connections are classified as a negotiated connection service.

2.3.3 Negotiated connection service

A connection that does not meet the requirements of a basic or standard connection service is a negotiated connection service.

Most negotiated connection services are classified as a standard control service, meaning that the connection charges are approved by the AER.

An enhanced connection service is a specific type of negotiated connection service. This is a connection where the service is provided:

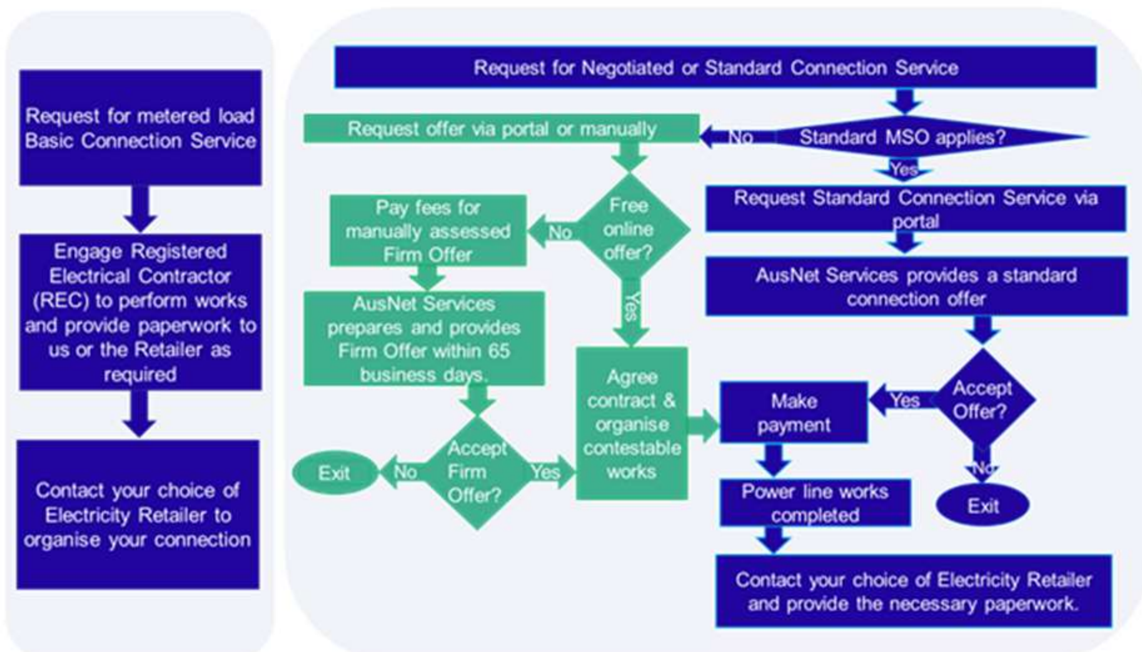
- With higher reliability standards, or lower reliability standards (where permissible) than those specified in the NER or any other applicable regulatory instruments; or
- At service levels or plant ratings in excess of those required by the regulatory framework to be provided by us.

Enhanced connection services have been classified by the AER as alternative control services and connection charges will be calculated as quoted services.

2.4 Connection process and expedited connections

The figure below shows the typical steps required when arranging an electricity supply to a property. It illustrates the simplified process for obtaining a basic connection service or standard connection service, which does not require any negotiation between the connection applicant and us.

Figure 3: Process for arranging an electricity supply



We will use our best endeavours to provide a connection applicant with an offer for:

- A basic connection services MSO within 10 business days, or
- A standard connection services MSO within 20 business days.[4]

We will notify the connection applicant within 10 business days if their request does not satisfy the relevant qualifying conditions applying to that service. In those circumstances, the customer will require a negotiated connection service.

If a connection applicant does not require a connection offer or a signed agreement for a basic connection service, the applicant may apply for an expedited connection. An expedited

[4] We will provide an offer within 10 business days of conducting a site-specific assessment or site inspection. It may take up to 10 business days to conduct a site-specific assessment or site inspection.

connection request requires the applicant to contact their electricity retailer and provide the necessary paperwork from a Registered Electrical Contractor.

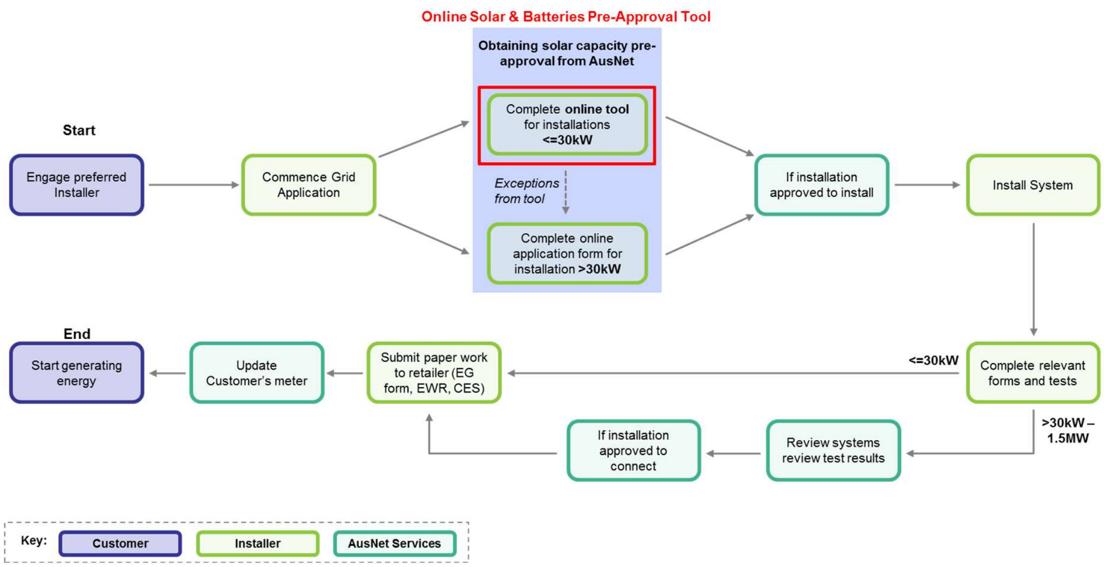
For an expedited connection, we are taken to have made, and the connection applicant is taken to have accepted, a connection offer in accordance with the relevant MSO on the date we receive the application. An expedited connection is subject to the same qualifying conditions as a basic connection service. We will notify the customer as soon as possible if it becomes evident that these conditions are not satisfied.

2.4.1 Connections of embedded generation

We have an online tool that instantly assesses applications to connect solar and/or battery systems up to 10 kVA maximum inverter capacity per phase (all SWER connections must be assessed on a case by case basis) and 5 kW (3.5 kW for SWER) total export limit per phase. This online tool can be found on our website: https://www.ausnetservices.com.au/New-Connections/Solar-and-Battery-Connections/Small-Simple-Solar-Installations/Pre-approval-Tool-Welcome

For systems greater than 30 kVA capacity and 15 kVA export, the connection applicant must apply for a manual technical assessment using the link above.

Figure 4: Diagram of process for embedded generator connections



2.5 Overview of connection charges

The charges payable for a connection application will depend on the nature of the connection service required, the demand and consumption profile and the work involved in establishing the connection. The connection charges that a connection applicant may be required to pay can include one or more of the following cost components:[5]

- Fees for connection services;
- A capital contribution (CC) charge;
- Metering costs;

[5] These components are set out in clause 5A.B.2(b)(5) of the NER and, in relation to pioneer schemes, clause 6.1.5 of the AER's connection charge guidelines for electricity retail customers.

- Costs of minor variations;
- Other incidental costs; and
- Charges payable to account for any pioneer schemes (also known as reimbursement schemes).

The table below describes each of these cost elements.

Table 2-2: Summary of connection fees and charges

Fee or charge group	Description
Connection Service Fee	These fees cover the cost of the connection assets or alteration of the existing connection, including design, construction, commissioning and energisation of connection assets. The various connection services offered by us are defined in Table 2-3 in section 2.6 of this Connection Policy. The fees for these services are approved annually by the AER. Fees for connection services will need to be paid directly by the connection applicant.
Capital Contribution Charge	CCs for extension or augmentation of the distribution system (including the customer's connection assets) may apply to connections where the expected demand exceeds an augmentation threshold. Our augmentation threshold is: • 10 kVA on SWER lines[6], or • 100A single phase, or 100A per phase of a multi-phase supply. The rationale for these thresholds is discussed in section 2.7 of this Connection Policy. All connection applicants will pay a CC for any new network extensions required for their new connection or connection alteration, in addition to any augmentation of the connection assets. CCs are calculated in accordance with section 2.7 of this Connection Policy.[8] CCs do not apply in relation to basic connection services.
Metering costs	The connection may require a change of meter, which would incur a metering charge. The metering costs will be charged in accordance with our published fees.
Minor variations	These costs arise if the connection requirements vary from the standard specifications as detailed in the applicable MSO or as otherwise agreed with the connection applicant.
Other incidental costs	The connection applicant may be required to pay incidental costs arising from the connection, as detailed in the relevant MSO or as otherwise agreed with the connection applicant.

[6] SWER line means a single wire earth return (that is, a single-wire electricity distribution line which supplies single phase electrical power such that the earth is used as the return path for the current).

[8] Our CCs are calculated in accordance with section 5 of the AER's guidelines and the connection charge principles in clause 5.A.E1(c) of the NER.

Fee or charge group	Description
Pioneer Scheme Charge	Where a connection is made to an extension funded by an original customer, we may be required to refund customers already connected to the extension under a pioneer scheme (reimbursement scheme). The connection applicant (the subsequent customer) may be required to share costs of the original customer's connection by making an appropriate contribution towards the cost of the shared line.

Further information on the calculation of these cost components is provided in later sections of this Connection Policy and in the MSO for basic connection services and the MSO for standard connection services.

2.6 Regulation of connection fees

As noted in the previous section, the connection service fee is a component of the total cost of a connection. The AER classifies connection services depending on the nature of the service and the extent of competition in the provision of the service.

The AER's connection charge guideline requires us to apply different connection charges depending on the AER's service classification. Given this requirement, the table below maps our connection services to the AER's service classification for regulatory purposes.

Table 2-3: Connection services and the AER's service classification

Service group	Further description	AER's Service Classification
Basic connection service	Means a *connection service* related to a *connection* (or a proposed connection) between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances: (a) either: 1. the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or 2. the retail customer is, or proposes to become, a micro embedded generator; and (b) the provision of the service involves minimal or no augmentation of the distribution network; and (c) a MSO has been approved by the AER for providing that service as a basic connection service.	Alternative control
Standard connection service	Means a connection service (other than a basic connection service) for a particular class (or sub-class) of connection applicant and for which a MSO has been approved by the AER.	Standard control
Negotiated connection	Means a connection service (other than a basic connection service) for which a DNSP provides a connection offer for a negotiated connection contract. This includes connections under Chapter 5 of the NER.	Standard control

Service group	Further description	AER's Service Classification
Connection application and management services	Connection application related services Works initiated by a customer or retailer that are specific to the connection point. This includes, but is not limited to: • field based de-energisation and re-energisation • non-basic supply abolishment or reposition non-basic connection • temporary connections (e.g. for builder's supply, fetes etc.) • overhead service line replacement – customer requests the existing overhead service to be replaced (e.g. because of a point of attachment relocation). No material change to load • protection and power quality assessment • supply enhancement (e.g. upgrade from single phase to three phase) • customer requested change requiring primary and secondary plant studies for safe operation of the network (e.g. change protection settings) • upgrade from overhead to underground service • rectification of illegal connections or damage to overhead or underground service cables • calculation of a site specific distribution loss factor on request in respect of a generating unit up to 10 MW or a connection point for an end-user with actual or forecast load up to 40 GWh per annum capacity, as per clause 3.6.3(b1) of the NER • calculation of site specific loss factors when required under the NER • power factor correction • embedded network management • assessing connection applications or a request to undertake relocation of network assets as contestable works and preparing offers • processing preliminary enquiries requiring site specific or written responses • undertaking planning studies and associated technical analysis (e.g. power quality investigations) to determine suitable/feasible connection options for further consideration by applicants • liaising with groups representing multiple connecting parties (e.g. community group upgrades) • site inspection in order to determine the nature of the connection service sought by the connection applicant and ongoing co-ordination for large projects • registered participant support services associated with connection arrangements and agreements made under Chapter 5 of the NER.	Alternative control

Service group	Further description	AER's Service Classification
Enhanced connection services (a specific type of negotiated connection service)	Other or enhanced connection services provided at the request of a customer or third party that include those that are provided: • with higher reliability standards, or lower reliability standards (where permissible) than those specified in the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance. • at service levels or plant ratings in excess of those required by the regulatory framework to be provided by us.	Alternative control
Public lighting	Public lighting services (including emerging public lighting technology), including: • operation, maintenance, repair and replacement of public lighting services; • alteration and relocation of public lighting assets; • new public lighting services; and • provision, construction and maintenance of emerging public lighting technology.	Alternative control

The AER regulates the fees that we charge for the connection services set out above. The fees and the regulatory arrangements for annual changes are detailed in the current Victorian electricity distribution determination. We submit an annual pricing proposal for the AER's approval to update the applicable fees in accordance with the AER's determination.

For a complete list of our current services and fees, please refer to our Annual Pricing Proposal: https://www.ausnetservices.com.au/Misc-Pages/Links/About-Us/Charges-and-revenues/Network-tariffs

2.7 Capital contributions

A CC is a contribution paid by the connection applicant towards the cost of extending or augmenting the distribution network or installing or upgrading new connection assets required to enable the new connection or connection alteration to be made. Where a CC is required, we will specify the amount of the contribution in the connection offer. The CC must be paid as a lump sum before we will commence any works.

CCs for network augmentation (other than a network extension beyond the standard service line) are not required where:

- The connection service is offered under the terms and conditions of a basic connection offer; or
- Maximum demand at the connection point does not exceed:
  - 10kVA on SWER lines, or
  - 100A single phase, or 100A per each of the phases of a multi-phase low voltage supply (the augmentation threshold).

These maximum demand thresholds have been determined having regard to the principles set out in the AER guidelines for setting such thresholds. Based on the limited available capacity on SWER lines, the rural nature of our distribution network, and the average size of the connecting customers, we consider that a threshold above 10kVA for SWER connections would drive significant augmentation costs that would be unfair to share across all customers.

Where applicable, the CC amount will be calculated in the following manner:

Capital Contribution (CC) = ICCS + ICSN – IR(n=X)

Where:

ICCS = Incremental Cost Customer Specific

ICSN = Incremental Cost Shared Network

IR (n=X) = Incremental Revenue.

A CC is only payable where the incremental costs exceed the incremental revenue (i.e. CC > $0).

2.7.1 Incremental cost of customer specific connection assets

The Incremental Cost Customer Specific (ICCS) is the incremental costs we incur that are specific to the connection, such as network extension assets and augmentation of connection assets at the premises. The ICCS is calculated as the sum of the incremental costs specific to the connection, such as:

- Design and construction of new customer-specific connection assets;
- Design and augmentation of any existing connection assets at the customer's premises;
- Network extension costs;
- Administration costs (including design and certification costs);
- Tender costs (where applicable); and
- The provision of any other connection services that are to be used solely by the connection applicant.

Overheads will be applied in addition to the costs specific to the connection.

For the ICCS, we will:

- Determine the cost in a fair and reasonable manner and ensure that the cost estimate is reflective of the efficient cost of performing the service;
- Calculate the cost on the basis of the least cost, technically acceptable standard necessary for the connection[9], unless the connection applicant requests a connection service (or part thereof) to be provided to a higher standard. In these circumstances, the connection applicant is required to pay for the additional cost of providing the services to the higher standard; and
- Include the relevant operating and maintenance costs for servicing the connection in the calculation of incremental cost and incremental revenue.

Where we elect to provide the service to a higher standard or capacity than necessary to meet the connection applicant's requirement (other where the applicant is a real estate developer), we will not charge the connection applicant for the additional cost. Where the connection applicant is a real estate developer, we may provide the service to a higher capacity to efficiently provide for forecast load growth at that location, and may charge the developer accordingly. The treatment of connection applications from real estate developers is discussed in Chapter 6 of this Connection Policy.

2.7.2 Incremental cost of shared network

The Incremental Cost Shared Network (ICSN) is the network cost we incur as a result of a new or altered connection, but which is not specific to the connection e.g. network augmentation (other

[9] The least cost, technically acceptable standard may also depend on the location and nature of the connection. Please refer to section 7.3 of this Connection Policy for further details.

than an extension beyond the standard service line). The ICSN is determined on the basis of unit rates:

ICSN = Unit Rate × Demand Estimate

Where:

Unit Rate = Average cost of augmentation (other than an extension beyond standard service line) per unit of added capacity, expressed as $/kVA

Demand Estimate = Estimated maximum demand at the connection point, measured in kVA

We will apply the above ICSN formula when the connection applicant's expected demand is above the augmentation thresholds as described in section 2.7 of this Connection Policy. The unit rates used to determine the ICSN are consistent with our approach in the AER's Electricity Distribution Determination for the previous 2016-20 regulatory period, except for the inclusion of REFCL specific rates.

We propose to include Marginal Cost of Reinforcement (MCR) with REFCL variations in each connecting customer's CC. The MCR concept, and underlying basis for its calculation, aligns with the ICSN component of the Customer Contribution Formula. In parts of the network where REFCL technology is operating, the cost of augmentation for new HV connected load contributes to the eventual need to upgrade the upstream distribution system REFCL technology.

The calculated unit rates reflect the average cost of shared network augmentation recently undertaken by us, on a $/kVA basis, for the following network components:

- Low voltage mains;
- Distribution substation;
- Higher voltage feeder (REFCL or non-REFCL);
- Zone substation (REFCL or non-REFCL); and
- Sub-transmission line.

The unit rates vary according to the network component requiring augmentation, reflecting the cost that we incur in adding each unit of capacity to the network (measured in kVA), exclusive of overhead costs. The unit rates reflect the useful life of the network assets and the assumed period that the connection applicant is expected to use the network.

The applicable unit rates for residential and business customers in 2020 are presented in the following table.

Table 2-4: Augmentation unit rates, ($ per kVA, $2020 excluding overheads)

	Residential customers (non-REFCL)	Business customers (non-REFCL)	Residential customers (REFCL)	Business customers (REFCL)
LV feeder	$743,751	$440,845	$743,751	$440,845
Distribution substation	$592,256	$351,049	$592,256	$351,049
HV feeder	$348,482	$206,557	$412,783	$244,670

	Residential customers (non-REFCL)	Business customers (non-REFCL)	Residential customers (REFCL)	Business customers (REFCL)
Zone substation	$251,370	$148,995	$315,671	$187,109
Sub-transmission line	$51,526	$30,541	$51,526	$30,541

Source: AusNet Services

In addition to the quoted augmentation unit rates presented in Table 2-4 above, we will apply:

- Price escalation in each year according to movements in the Consumer Price Index (CPI); and
- An overhead charge.

In determining the connection applicant's demand estimate for the purposes of the ICSN calculation, we will:

- Apply an average diversity factor for the corresponding customer type to estimate the customer's expected contribution to system peak, coincidental demand; and
- In the case of a request to alter or upgrade an existing supply, apply an average diversity factor to the estimated increase in the connection applicant's maximum demand at the time of system peak.

In respect of these diversity factors:

- The cumulative diversity factor applied will vary depending on the point of connection; and
- The diversity factors vary for residential and business customers, reflecting the variations in the expected load placed on the network by different types of customers.

We will apply the unit rates listed in Table 2-4 for all negotiated load connections where the cost-revenue test is applied, except for very large high voltage customers that require major upstream augmentation such as the establishment of a new zone substation and/or 66 kV feeder assets including major upgrades. In such cases, we will estimate the cost of the shared network components used by the customer, having regard to the amount of capacity required to meet specific connection requirements and the retail customer's estimated maximum demand.

We will also include the relevant operating and maintenance costs for servicing the connection in the calculation of the incremental cost of shared network.

The process for determining the estimated maximum demand is described in greater detail in section 2.9 of this Connection Policy.

2.7.3 Incremental revenue calculation

The Incremental Revenue (IR(n=X)) is the present value of the incremental revenue stream expected to be received from the new or altered connection over a pre-defined period. For residential premises, this is 30 years. For commercial and industrial premises, the period varies depending on the nature of the business and will be defined in the connection offer to a maximum of 15 years.

To estimate the incremental revenue, we will:

- When calculating the present value of the revenue stream, apply the pre-tax weighted average cost of capital as:
    - set out in the AER's Final Distribution Determination, or

  - updated annually in accordance with the AER's Final Distribution Determination;

- Use the price profile in the Final Distribution Determination and apply a flat profile in real terms thereafter;
- Remove the component attributable to shared network augmentation costs from the network tariff where a customer's expected demand is below the augmentation threshold (in accordance with the AER connection charging guideline, clause 5.3.1(b)); and
- Include the component attributable to incremental operational and maintenance costs in the network tariff.

All CCs will be calculated specifically for the connection applicant except in the case of standard connection services, where we will apply pre-calculated CCs. Standard connection services are discussed in Chapter 4 of this Connection Policy.

2.8 Higher standards under Electricity Safety (Bushfire Mitigation) Regulations

The least cost technically acceptable standard may depend on the location of the connection. For example, a higher standard may apply in areas specified as hazardous bushfire risk areas for the purposes of the Electricity Safety (Bushfire Mitigation) Regulations 2013. In these circumstances, the connection applicant will be required to pay for the additional cost of providing the services to the higher standard.

A codified area will usually require the use of covered or insulated conductor. A supply fed from a zone substation supported by REFCL technology or its transfer feeders may require additional works to maintain the capacity prescribed by the Electricity Safety (Bushfire Mitigation) Regulations 2013.

2.9 Measuring demand and consumption

Where the connection applicant is required to make a CC, the connection offer will set out the demand and consumption estimates used to determine the CC.

In general, the demand and consumption estimates will reflect the information supplied in the connection application. However, we may also have regard to the actual consumption and demand information from existing connections with similar characteristics. The demand and consumption estimates will account for the load characteristics, which will reflect the impacts of any embedded generation relevant to the connection offer.

Where we and the connection applicant cannot agree on the demand and consumption estimates for use in determining the CC payable, we will apply a provisional estimate.

Where a provisional estimate is applied , the connection applicant may be subject to an additional charge or receive a refund of an upfront security deposit once the difference between the actual consumption and demand and provisional estimates of consumption and demand is assessed.

We will assess the additional charge or security deposit refund payable within three years of the connection being energised. The amount of the additional charge or security deposit refund will be the difference between the actual CC paid and the contribution calculated using the actual demand and consumption.

A security deposit refund will only be paid where the connection applicant is still solvent and continuing to utilise the premises at the contracted demand rates.

2.10 Pioneer schemes

It is important that customers share in the costs of extending the network. Cost sharing arrangements or 'Pioneer Schemes' ensure that a customer that initially funds a network extension recovers part of their expenditure when other customers subsequently make use of that asset. For new connections that require network extensions, we will apply a Pioneer Scheme in accordance with the AER's connection charge guidelines.

The Pioneer Scheme means that a connection applicant may be required to contribute to the costs of an existing line that is subject to the scheme as part of their connection fees and charges. The amount the customer will need to pay will be identified in our connection offer. If other customers subsequently connect, the connection applicant may recover a proportion of the contribution they paid from the subsequent customers.

We apply the following principles under the Pioneer Scheme:

- The scheme applies for seven years after the network extension is complete.
- Capital contributions made in relation to an augmentation or alterations that did not involve a network extension are not subject to the Pioneer Scheme.
- Each extension is subject to a separate cost sharing arrangement under the Scheme, even if it connects to a pre-existing extension.
- The capital contribution paid by the customer for the network extension (which includes contributions to upstream augmentation and connection assets) is the maximum amount that may be recovered from new customer(s).
- The reimbursement amount payable by new customer(s) in relation to a network extension is based on the depreciated value of the relevant assets at the time of the connection application and the relative usage made by the new and existing customers, taking into account:
    - the physical attributes of the assets to be used by the new customer(s) (for example, length of line) relative to other customers already connected to the extension;
    - the amount of electricity demand forecast to be used by the new customer(s) relative to other customers already connected to the extension; and
    - the depreciated value of the assets, calculated on a straight line basis over a period of 20 years for the purpose of the scheme.
- A reimbursement under the Pioneer Scheme will only be paid where the minimum threshold is met. In accordance with the AER's connection charge guideline, the reimbursement threshold is $ 1,156 for 2020.[10]
- Where a reimbursement is payable, the payment is made to the original connection applicant(s) that contributed to the relevant network extension.
- Where the network extension was built by a third party, we estimate the cost of the extension and adopt this as the amount we would have charged to build the extension.
- Where the original extension was built to a higher standard or capacity than the least cost technically acceptable standard required by the original customer, the cost of constructing the network extension to the least cost technically acceptable standard will be used for the purpose of the Pioneer Scheme.
- In relation to real estate developments, the Pioneer Scheme only applies to customers connecting to the extension assets outside the pioneer developer's site boundary and not to premises connecting within the development.
- The Pioneer Scheme replaces our earlier cost sharing arrangements. We will resolve any inconsistencies arising from earlier schemes and the current Pioneer Scheme by exercising reasonable discretion, having regard to the AER's connection charge guidelines and our previous practices.

[10] This figure reflects the AER's threshold of $1,000 (2012 dollars), updated for CPI. The threshold will be updated annually by applying ABS CPI All Groups, Weighted Average of Eight Capital Cities, March to March Quarter.

2.11 Other cost sharing arrangements

We may offer alternative cost sharing arrangements to those provided by the Pioneer Scheme.

Alternative cost sharing arrangements are specifically designed for circumstances where land adjacent to a development is expected to be rezoned for real estate development. In these cases, it is important that the electricity infrastructure is appropriately sized and the associated costs are shared appropriately between the initial and subsequent customers.

In broad terms, the alternative cost sharing will apply a $/lot rate to reflect an appropriate contribution to the initial costs of the infrastructure. The calculation of the $/lot rate and the payment arrangements will be subject to negotiation between us and the developer.

Where these cost sharing arrangements apply, it is not necessary or appropriate to apply the Pioneer Scheme.

3 Basic connection services

3.1 Qualifying conditions

The majority of our new connections for load and solar Photovoltaics (PVs) do not require any augmentation. As such, the connection application process is relatively simple and the connection timeframes are typically within 10 business days from the customer's acceptance of a connection offer.

For a connection to be classified as a basic connection service, the proposed connection must satisfy several qualifying conditions, which are set out in the table below. These qualifying conditions ensure that more complex connections, including those requiring augmentation of the distribution network, are not inappropriately classified as basic connection services.

Table 3-1: Qualifying conditions for basic connection services

Basic connection service	Qualifying conditions
Customer connection to the distribution network	For connection of residential and small business premises where: • A low voltage supply with the necessary capacity is available; • Minimal or no augmentation is required; • The maximum connection capacity does not exceed 100A[11] in total with no more than 40A per phase; • The connection complies with our technical and metering requirements, as outlined in the relevant MSO; and • The proposed connection is not to a SWER line.

Embedded generator connection to the distribution network	For connection of a micro embedded generator where:
	• A low voltage supply with the necessary capacity is available;
	• The export capability and inverter capacity is consistent with the requirements of AS4777;
	• The proposed connection satisfies our safety and technical requirements;[12]
	• Minimal or no network augmentation is required;
	• The total maximum export of all micro embedded generating units connected must not exceed:
	  ○ 5kVA in the case of single-phase connections per phase; and
	  ○ 3.5kVA in the case of SWER connections.
	• The total maximum inverter capacity of all micro embedded generating units connected must not exceed 10kVA per phase

[12] Our safety and technical requirements are specified in the MSO. It should be noted that these requirements may change from time to time in response to technological developments and operational experience.

[12] Our safety and technical requirements are specified in the MSO. It should be noted that these requirements may change from time to time in response to technological developments and operational experience.

Basic connection service	Qualifying conditions
	and all SWER connections must be assessed on a case by case basis.

Source: AusNet Services, Attachment Model Standing Offer for Basic Connection Services Basic Micro Embedded Generation (Inverter Energy System – Battery, Solar, Wind).

If the above conditions are not satisfied, the connection application will be classified as a standard connection service or negotiated connection service (see Chapters 4 and 5 of this Connection Policy).

It should also be noted that connection applicants who are entitled to a basic connection service or standard connection service have a right to negotiate the terms and conditions of their connection offer. Where the connection applicant prefers a negotiated outcome, the MSO (and the associated processes) for basic connection services do not apply. In these circumstances, we will offer a negotiated connection service (see Chapter 5 of this Connection Policy).

3.2 Basic customer connections to the distribution network

We will provide the following basic connection services for customer connections to the distribution network:

Table 3-2: Basic connection types for customer connections

Connection types	Description
Routine connection of new premises – customers up to 100A	Connection services to customers making connection of a new premise to the network. This service includes: • the provision of a service cable in areas with overhead supply; and • making a connection in an existing pit for customers in underground supply areas. See Table 3-3 for further details.
Temporary connections and disconnections	Distributors provide temporary connection and/or disconnection services to specific customers on request. This is most commonly used for construction sites, although other examples include blood bank vans and community fetes.

We offer several different types of connections as basic connection services. The table below describes each of these services.

Table 3-3: Routine Connections up to 100A

Service Name	Description
Single overhead (single-phase) connection	Establish a single-phase connection between the connection point at a premises and our distribution system. The connection will be between the connection point and an existing low voltage pole no longer than permitted in the Victorian Service and Installation Rules, on the same side of the street with no requirement to cross another property, and complying with statutory clearance requirements over driveways.[13]
Multi overhead (multiphase) – direct connected meter	Establish a multiphase connection between the connection point at a premises and our distribution system. The connection will be between the connection point and an existing low voltage pole no longer than permitted in the Victorian Service and Installation Rules, on the same side of the street with no requirement to cross another property, and complying with statutory clearance requirement over driveways. The service is dependent upon the requested number of phases being available from existing network assets. A current transformer (CT) connected meter service is also available, but the connection is likely to exceed 100A on any phase a on 3 phase low voltage supply and therefore will be provided as a negotiated connection service.
Single underground (single-phase) connection	Establish a single-phase connection at a connection point between the premises and our distribution system. The connection point will be in an existing service pit or pillar located on the property boundary that has sufficient capacity for the connection requested. The location of the connection point must not require the consumer mains to cross another property.
Multi underground (multiphase) – direct connected meter	Establish a multiphase connection at a 'connection point' between the premises and our distribution system. The connection point will be in an existing service pit or pillar located on the property boundary that has sufficient capacity for the connection requested. The location of the connection point must not require the consumer mains to cross another property. The service is dependent upon the requested number of phases being available from existing network assets. A CT connected meter service is also available, but the connection is likely to exceed 100A on any phase on a 3 phase low voltage supply and therefore will be provided as a negotiated connection service.

[13] Section 7.4.4 of the Service Installation Rules (SIRs) requires a minimum line clearance of 4.6 metres (including in service sag) over driveways and vehicle accessible areas.

Service Name	Description
Temporary overhead supply	Establish a single-phase connection at a 'connection point' between the premises and our distribution system. The connection point will be on an existing low voltage pole no longer than permitted in the Victorian Service and Installation Rules, on the same side of the street with no requirement to cross another property, and complying with statutory clearance requirements over driveways.

3.3 Basic micro embedded generator connections

For micro embedded generators that qualify as a basic connection service, we conduct an automatic assessment and approval process at no cost to the customer. An expedited application process is available online, whereby the connection application is taken to have accepted our basic connection service offer by submitting the connection application. Where there is insufficient information to process an expedited assessment or there are capacity constraints on the network, a manual technical assessment will be undertaken.

We do not levy a specific connection service fee for basic micro embedded generator connection applications. However, ancillary services may be required of the kind set out in the table below. The cost of these services will be charged to the connection applicant.

Table 3-4: Connection application and management services for micro embedded generation

Service name	Service description
Meter exchange upon installation of a small scale renewable energy generation system	A meter is required to be changed at a site as a result of the installation of a renewable energy installation such as solar generation.
Meter reconfiguration upon installation of a small scale renewable energy generation system	An existing meter is required to be reconfigured at a site as a result of the installation of a renewable energy installation such as solar generation.

3.4 Fees and charges

The following table sets out the fees and charges that may be payable under a MSO for basic connection services or MSO for basic connection services (Micro Embedded Generation).

Table 3-5: Applicable fees for basic connection services

Service charge group	Routine connection of new premises – customers up to 100A	Temporary connections and disconnections	Micro embedded generation
Fees for connection services	✓	✓	✗[14]
Capital contribution for network extension[15]	✗	✗	✗
Charges for connection augmentation[16]	✗	✗	✗
Capital contribution for network augmentation[17]	✗	✗	✗
Charges for meter type	As required	As required	As required
Minor variations/other incidentals	As required	As required	As required
Reimbursement Payment (Pioneer Scheme) - See section 3.6 below.	As required	✗	As required

3.5 Capital contributions

For basic connection services, the connection applicant is not required to pay a CC for shared network (upstream) augmentation (such as a requirement to increase the distribution network capacity because of the applicant's connection).

Where a new connection gives rise to a need for a network extension or augmentation of the shared network or existing connection assets, the applicant is required to contribute to the cost of these works. In these circumstances, the connection service is classified as a standard or negotiated connection service and the relevant provisions described below apply.

3.6 Pioneer Scheme

As explained in section 2.10 of this Connection Policy, we apply a Pioneer Scheme in accordance with the AER's connection charge guideline. To give effect to this arrangement, a connection applicant may be required to make a reimbursement payment where the proposed connection makes use of a network extension that was initially funded by another customer.

3.7 Payment of connection charges

The total connection charges payable is the sum of the applicable fees and charges set out in

14 Customers requesting a micro embedded connection will either already have an existing connection service or will request a connection service and pay the relevant service fee for connection to the distribution network.

15 If a network extension is required, the connection service is a negotiated connection service.

16 If augmentation of the connection assets is required, the connection service is a negotiated connection service.

17 The basic connection service does not include connections that require network augmentation.

Table 3-5. We require these charges to be paid as a lump sum at the time the connection offer is accepted, and prior to any construction work being undertaken. Alternatively, the customer may request the connection service through their retailer and the retailer will recover the costs from the customer.

3.8 Further information

Further information on basic connections is available in the following our publications:

- Basic Connections Standing Model Offer; and
- Customer Connection Guide.

These publications, and other related fact sheets, are available from our website: https://ausnetservices.com.au/New-Connections

4 Standard connection services

4.1 Qualifying conditions

We offer standard connection services for underground connections that require a network extension, not exceeding a specified distance from the existing low voltage supply. Customers may be eligible for a standard connection service depending on meeting the qualifying conditions for our pole-to-pit MSO.

We currently offer two standard connection services, with additional charges applicable if there is a road crossing or a site-specific Aboriginal cultural heritage due diligence assessment is required. We anticipate adding additional standard connection services during the 2022-26 regulatory period and these will be available on our website: https://www.ausnetservices.com.au/New-Connections/Electricity-Connections

A pre-calculated CC calculated in accordance with the formula set out in section 2.7 of this Connections Policy applies to the provision of each standard connection service, and must be paid by the connection applicant in accordance with the MSO. The amount payable is based on average cost and incremental revenue estimates. This approach delivers the following benefits to customers:

- It reduces the volume of customer-specific information required by us to prepare a quote for the connection service; and
- The customer is not required to pay a security deposit, because the capital contribution is based on average data, rather than the customer's particular usage.

We have also identified 'minor variations/other incidentals' that may be required by a customer, where:

- The proposed connection service crosses more than one road; and/or
- A site specific Aboriginal cultural heritage due diligence assessment is required.

To further assist customers, the MSO for standard connection services specifies the costs of these 'minor variations/other incidentals', in addition to specifying the pre-calculated capital contribution for each standard connection service.

The qualifying conditions for each standard connection service closely align with those for basic connection services. The key difference is that for standard connection services, the low voltage supply can be some distance from the customer's premises. Therefore, the qualifying conditions for each standard connection service are:

- A low voltage supply is available with the necessary capacity and within the specified distance from the proposed connection;
- Maximum connection capacity of 100A in total on 3 phase low voltage supply with no more than 40A per phase;
- Compliance with the technical and safety obligations; and
- Connection to a line that is not a SWER line.

We note that the standard connection service applies to single underground extensions, not to connection applications involving multiple underground extensions. If a connection application does not satisfy the qualifying conditions for a standard connection service, the connection will be classified as a negotiated connection service.

4.2 Standard connection to the distribution network

A description of the standard connection services is set out in the table below. To simplify the presentation of information in Table 4-1, we describe the underground extension of up to 40 metres to the existing overhead supply for one or two new customers.

Table 4-1: Standard connection types for customer connections

Standard connection service	Description
Underground extension (up to 40 metres) to the existing overhead supply, where the service would be used by one new customer	Provision of an underground connection service to a customer's single premises, where requested to do so by the customer, and the proposed connection point is within 40 metres of an existing low voltage pole. This service involves installing an underground service pit and undertaking the necessary trenching and boring. We offer two standard services at different prices, depending on whether the service is single use or dual use. If a road crossing is required, an additional connection service charge applies.
Underground extension (up to 40 metres) to the existing overhead supply, where the service would be used by two new customers	Provision of an underground connection service to a customer's single premises, where requested to do so by the customer, and the proposed connection point is within 40 metres of an existing low voltage pole. This service involves installing an underground service pit and undertaking the necessary trenching and boring. We offer two standard services at different prices, depending on whether the service is for single use (one customer) or dual use (two customers). If a road crossing is required, an additional connection service charge applies.

Source: AusNet Services, Attachment Model Standing Offer for Standard Connection Services Pole-to-Pit Connections

4.3 Fees and charges

The table below sets out the fees and charges that are payable under a MSO for the standard connection services. The underground extension to the existing overhead or underground supply does not include basic connection services for routine new connections and addition of micro EG generation. These basic connection services must be requested separately.

The table below simplifies the presentation by only showing the charges that apply for underground extensions to an existing overhead supply or an existing underground supply. The applicable charges are the same in both cases, as they are for each of the two standard connection services that we offer.

Table 4-2: Applicable fees for the standard connection service

Service Charge Group	Underground extension to the existing overhead supply	Underground extension to the existing underground supply
Fees for the relevant basic connection services	Requested separately	Requested separately
Pre-calculated capital contribution	✓	✓
Minor variations/other incidentals	As required	As required
Reimbursement payment (Pioneer Scheme) - see section 4.5 below.	As required	As required

4.4 Pre-calculated capital contributions

The AER's connection charge guidelines allow distributors to set a pre-calculated CC for connection applicants who are expected to have substantially the same connection service and expected usage characteristics. Pre-calculated CCs are specified in the MSO for Standard Connection Services.[19]

The AER's guideline requires that a pre-calculated CC charge must be included in a distribution network service provider's basic or standard connection offers and should:[20]

- Not create unreasonable cross-subsidisation within the class; and
- Reflect the average or typical CC that would be charged to connection applicants within the class, if the cost-revenue-test was individually applied to each connection applicant's connection service.

To ensure all customers are treated fairly and cross-subsidies are minimised, we have defined our underground connection services so that customers are likely to have similar connection service and usage characteristics.

In addition, as each standard connection service is essentially a basic connection service with a small underground extension, it is important that there is equitable treatment between customers requesting a basic connection service and those requesting a standard connection service. Given this objective, our approach is that a connection applicant for a standard connection service:

- Should pay the AER-approved connection fee for the equivalent basic connection service.
- Should pay the pre-calculated CC; and
- Should not contribute to the augmentation of the shared network, as basic connection service are not subject to these charges

4.5 Pioneer schemes

A connection applicant will be required to make a reimbursement payment where the proposed connection will make use of an existing network mains extension that was funded by an original customer through a CC. However, network extensions that are provided as part of a standard connection service featuring an underground extension to the existing overhead supply are not subject to the Pioneer Scheme, as the reimbursement amount will be below the threshold amount

[19] https://www.ausnetservices.com.au/-/media/Files/AusNet/New-Connections/Model-Standing-Offer-for-standard-connection-submission.ashx?la=en

[20] AER, Connection charge guidelines for electricity retail customers, June 2012, clause 5.5.2.

(as described in section 2.10 of this Connection Policy). In the case of a standard connection service including an underground extension to the existing underground supply, the extension is typically provided to real estate developers sub-dividing land and are not subject to Pioneer Scheme payments.

4.6 Payment of connection charges

The total connection charges payable is the sum of the applicable fees and charges set out in Table 4-2. We require the connection applicant to pay these charges as a lump sum at the time the connection offer is accepted, and prior to any construction work being undertaken.

4.7 Further information

Further information on the standard connection services is available in the following publications:

- Standard Connections Model Standing Offer; and
- Customer Connection Guide.

These publications, and other related fact sheets, are available from our website: https://ausnetservices.com.au/New-Connections

5 Negotiated connection services

This chapter provides information on our negotiated connection services. As previously noted, all connection applicants have the right to negotiate the terms and conditions of their connection offer. Where the connection applicant elects to negotiate the terms and conditions of their connection, the MSOs for basic and standard connection services do not apply.

5.1 Negotiated customer connections to the distribution network

We will provide negotiated connection services for customer connections to the distribution network, as set out in the table below.

Table 5-1: Negotiated connection types for customer connections

Negotiated connection service	Description
Routine connection of new premises – customers over 100A	Routine connection services to customers making connection of a new premise to the network where that customer is above 100A. These services do not require augmentation of the shared network.
New connections requiring augmentation	This service applies in circumstances where: • augmentation of the shared network is required; or • a network extension is required outside the scope of a standard connection service; or • alterations are required to existing connection assets.
Rearrangement of existing assets at customer request, excluding alteration and relocation of public lighting assets	Works associated with any rearrangement of existing assets at the customer's request.
Unmetered supply	Unmetered supply is rarely available to connection customers. Telstra and NBN are the primary customers that require unmetered supply.
Enhanced connection services (a specific type of negotiated connection service)	Other or enhanced connection services provided at the request of a customer or third party, including those that are provided: • With higher reliability standards, or lower reliability standards (where permissible) than those specified in the NER or any other applicable regulatory instruments. This includes reserve feeder installation and maintenance. • At service levels or plant ratings in excess of those required by the regulatory framework to be provided by us.

5.2 Negotiated embedded generation connections

Where an embedded generator connection does not qualify for the basic micro embedded generation connection then we will offer a negotiated connection service. We will undertake a manual assessment of the PV and small generator installation applications (described in the table below) to determine the technical implications of the proposed connection.

As noted in , a low voltage supply must be available to obtain a negotiated embedded generation connection service. If it is not, a connection application must be made concurrently. Where the connection applicant is also seeking a connection to the distribution network, the network requirements arising from the proposed connection of the embedded generator are considered at the same time. The CC for non-registered embedded generators that are also load customers is calculated based on the total cost of the works required to support both the generation (expected electricity output) and load components of the connection service.

For embedded generators above 5 MW, the contribution may also include an amount to reflect the tax we incur on the capital component of the expenditure, netting off the present value of the reverse cash flow resulting from the depreciation of the CC.

Table 5-2: Approval services for embedded generator connections

Service name	Description
Manual assessment of PV & small generator installation enquiry, 4.6 kW to 15 kW.	These services involve us manually assessing whether or not the connection of a PV or small generator installation at a particular site will have any technical implications for its upstream distribution network and require further augmentation. This only occurs in situations where a request for preliminary assessment of whether a DER connection would be allowed without network augmentation application is referred by the online site approval web portal for manual assessment.
Manual assessment of PV & small generator installation enquiry, 15 kW to 30 kW.	
Manual assessment of PV & small generator installation enquiry, 30 kW to 1.5 MW	A manual assessment will be performed on a quoted basis.

As part of the pre-approval process, we may recommend the customer install an export-limiting device to avoid incurring the cost of upstream augmentation. If the embedded generation applicant chooses not to install and export-limiting device, these augmentation costs would otherwise fall on us and other network customers. In these circumstances, the embedded generation connection applicant must obtain a 'new connection requiring augmentation' service and pay the associated connection costs.

The following ancillary services may also be required on completion of the embedded generation connection.

Table 5-3: Connection application and management services for embedded generation connections

Service name	Service description
Meter exchange upon installation of a small scale renewable energy generation system	The meter at the site must be changed as a result of the installation of a renewable energy installation such as solar generation.
Meter reconfiguration upon installation of a small scale renewable energy generation system	The existing meter at the site must be reconfigured as a result of the installation of a renewable energy installation such as solar generation.

5.3 Fees and charges

The fees and charges that are payable for a negotiated connection service are subject to negotiation with us. We will determine:

- The technical requirements for the proposed new connection or connection alteration;
- The extent and costs of any necessary augmentation of the distribution system; and
- Any consequent change in charges for distribution use of system services.

In accordance with clause 5A.C.4 of the NER, we charge the connection applicant a reasonable fee (a negotiation application fee) to cover expenses directly and reasonably incurred by us in assessing the application and making a connection offer.

The table below summarises the applicable fees for negotiated connection service.

Table 5-4: Connection charges for negotiated connection services

Fees and charges	Routine connections over 100A[23]	New connections requiring augmentation	Re-arrangement of existing assets	Unmetered supply	Embedded generation
Pre-approval service	✗	✗	✗	✗	✓
Negotiation application fee	✗	✓	✗	✓	✓
Design and construction of connection assets	As required	As required	As required	As required	As required
Capital contribution for network extension	✗	As required	✗	As required	As required
Capital contribution for network augmentation	✗	As required	As required	✗	As required

23 This service applies where there is no augmentation of the shared network required. If the connection requires augmentation, the charges for "New connections requiring augmentation" would apply.

Fees and charges	Routine connections over 100A[23]	New connections requiring augmentation	Re-arrangement of existing assets	Unmetered supply	Embedded generation
Tax cost	✗	✗	✗	✗	As required
Charges for meter type	As required	As required	As required	✗	As required
Minor variations/other incidentals	As required	As required	As required	As required	As required
Reimbursement Payment (Pioneer Scheme) - see section 5.6	✓	✓	✓	✗	✗[24]

5.4 Augmentation threshold

As shown in Table 5-4 (above), a CC for network extension or shared network augmentation may apply to some connections. However, a CC is not payable if the capacity of the connection does not exceed the following threshold:[25]

- 10 kVA for a connection to a SWER line; or
- A maximum capacity of 100A single phase, or 100A per each phase of a multi-phase low voltage supply elsewhere in our distribution network.

The rationale for these thresholds is explained in section 2.7 of this Connection Policy. Any CC is calculated in accordance with the formula, which is also set out in section 2.7 of this Connection Policy.

5.5 Payment of connection charges

The total connection charges payable are the sum of the applicable fees and charges set out in Table 5-4. We require these charges to be paid as a lump sum at the time the connection offer is accepted, and prior to any construction work being undertaken.

5.6 Pioneer scheme

As already noted, the Pioneer Scheme operates to ensure a fair sharing of network extension costs between existing and future customers.

A connection applicant may be required to make a reimbursement scheme payment where the connection will make use of a network extension that is subject to the Pioneer Scheme (i.e. the network extension was funded by an original customer via a CC).

Further detail on the application of the Pioneer Scheme, see section 2.10 of this Connection Policy.

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24 As the connection to the distribution network is a qualifying condition for this service, any reimbursement relating to a pioneer scheme would be made as part of the load connection.

25 No augmentation fee is payable if the connection service is offered under the terms and conditions of a basic connection offer (see section 2.7 of this Connection Policy) or a standard connection offer (see section 4.4 of this Connection Policy).

5.7 Security deposits and fees

We may require a connection applicant to provide a security deposit and may withhold a security fee from the deposit where:

- The customer fails to take supply/utilise the capacity of the new or additional assets within the first three years of supply being made available; or
- The customer discontinues the use of the supply without warning; or
- The customer's actual consumption is less than the amount estimated in calculating the CC.

Further information on the application of security deposits and fees is contained in section 7.2 of this Connection Policy.

5.8 Minimum demand agreements

As an alternative to charging a security deposit for a single site connection with minimum demand exceeding 50 kVA, we may negotiate a minimum demand agreement with the customer. Under this arrangement, the customer agrees to be assigned to a minimum demand-based network tariff for a specified period. This approach gives us greater certainty about our ability to recover the costs we incur when providing the connection service. The terms of any such agreement will depend on the circumstances and will be subject to negotiation.

5.9 Further information

Further information on negotiated connections is available from our website: https://ausnetservices.com.au/New-Connections

6 Real estate developers

6.1 Overview

Real estate developers are responsible for the design and construction of electrical reticulation and connection assets within the boundaries of their property development. For this Connection Policy, real estate development includes the commercial development of land in one or more of the following ways:

- Residential housing and commercial / industrial subdivisions;
- Construction of commercial and / or industrial premises (e.g. shopping centres); and
- Construction of multiple new residential premises.

Connecting real estate developments to our distribution network typically involves extending the distribution network and augmenting the upstream network. These works are necessary to ensure the network is sized to allow for the expected future electricity demand from the development.

All connections for real estate developments are subject to a Negotiated Connection Offer. Connection applications for real estate development connections will only be accepted from the real estate developer.

6.2 Connection charges

The connection charges for real estate developments are summarised in the table below:

Table 6-1: Applicable charges for negotiated connection services

Fees and charges	Applicable to a negotiated connection service?
Negotiation Application Fee	✓
Design and construction of connection assets	As required
CC for network extension and/or modification	As required
CC for network augmentation	As required
Charges for meter type	As required
Minor variations/other incidentals	As required
Reimbursement Payment (Pioneer Scheme)	As required

These charges relate solely to the connection of the real estate development to the distribution network, and are additional to any costs the real estate developer may incur in the design and construction of reticulation assets within the development.

The connection charges are payable in accordance with the terms and conditions set out in our negotiated connection offer.

6.3 Capital contributions

The CCs for augmentation of the shared network are calculated in accordance with section 2.7 of this Connection Policy, with the exception that the augmentation threshold does not apply (as mandated by the AER's connection charge guidelines and the NER).

A real estate developer is treated as a single customer for the purpose of calculating a CC. The estimated incremental revenue from the development includes all the sites/connection services within a real estate development. The incremental costs may include the costs of the connection services and the efficient cost of providing for forecast demand.

6.4 Pioneer scheme

Real estate developers seek to recover their connection costs through the sale of real estate. As such, it is not appropriate to require customers within a development to make payments to share the connection costs. Therefore, developers are typically not entitled to receive the reimbursement payments under the Pioneer Scheme.

There is an exception for line extensions that are outside the developer's site boundary. Under this exception, a developer may receive a rebate if that line extension is later used by a subsequent real estate development outside the initial development. Similarly, developers may be required to make a reimbursement scheme payment where their development makes use of a network extension that is subject to a Pioneer Scheme (i.e. that was funded by an original customer via a CC).

As explained in section 2.10 of this Connection Policy, we may negotiate alternative cost sharing arrangements with developers, under which a charge is levied on a $/lot basis. Such arrangements may be a more efficient and administratively simpler way to ensure effective cost sharing.

6.5 Payment of connection charges

The total connection charges payable by the connection applicant is the sum of the applicable fees and charges set out in Table 6-1 above. At our discretion, the payment terms may be subject to negotiation between the parties. In the absence of mutually acceptable terms, the connection cost must be paid as a lump sum at the time the connection offer is accepted, and prior to any construction work being undertaken.

6.6 Security deposits and fees

We require the developer to provide a security deposit and may charge the customer a security fee from the deposit to mitigate the risks to us from the development, including the risk that we may not recover the projected future revenue from the provision of standard control services.

Further details of the application of security fees are provided in section 7.2 of this Connection Policy.

6.7 Further information

Further information for connection of real estate developments please contact us by calling 1300 360 795 or emailing us via supplyrequest@ausnetservices.com.au.

7 Other matters

7.1 Contestable services

There are certain tasks in the connection process that only we can undertake for safety or operational reasons, such as auditing third party network system designs and connection assets. We will allow customers to arrange most other works, including the tendering and construction of extension works. Works that can be undertaken by a third party are "Contestable Services", and typically include:

- Project management;
- Some design, including surveying and drafting services; and
- Construction, which includes the provision of all materials and 'as-constructed' plans.

The cost of Contestable Services depends on several variables, including:

- The distance of line extension to the property;
- Addressing environmental considerations (such as impacts on trees) or overcoming objections from third parties;
- The type and size of equipment used to provide the amount of supply requested; and
- Meeting regulatory requirements, such as those applied by the Victorian Government and local Councils.

A customer can elect to use an Approved Contractor (instead of us) to provide Contestable Services. An Approved Contactor has demonstrated to us that they have the necessary qualifications, training, experience, and quality systems of work to provide the Contestable Services lawfully and safely. If the customer elects to use an Approved Contractor, the customer can request that we conduct the tender exercise on their behalf. A fee applies for this service.

All Contestable Services designs are subject to approval by us. This ensures the designs are technically appropriate and have considered the overall impact and potential future needs of the electricity network.

When the customer chooses an Approved Contractor to perform Contestable Services, we may require a Refundable Guarantee from the customer to cover any costs associated with fixing faults or defects that may arise from the contractor's work. Any unused portion of the Refundable Guarantee will be returned after one year from the completion of the connection works.

A compliance audit of the Approved Contractor's work must be completed to ensure compliance with our construction standards prior to connecting to our system. This inspection is necessary as we are responsible for the safety and future maintenance of the line after connection occurs. The customer must pay the Audit Fee for this inspection and any necessary subsequent inspections.

7.2 Charges for connection services classified as alternative control services

Alternative control services are customer specific or customer-requested services. Where alternative control services are provided by us, the full cost of the service can be recovered from the customers using that service.

Alternative control services are charged on either:

- Fixed fee basis – this is where the scope of the connection service is predictable and the AER has approved a fee for the service, for example basic connection and public lighting operation, maintenance, repair and replacement of public lighting services.

- Quoted basis – using the labour rates approved by the AER, along with a pass through of material, contractor costs and tax. We determine charges on a quoted basis where the scope of the service vary significantly between customer requests and prices can only be determined when the scope of the work in known.

Our method for determining the charge for a connection service on a quoted basis is set out below.

Price = Labour + Contractor Services + Materials + Tax

Where *Labour* consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs, overheads and margin. *Labour* is escalated annually by:

$$(1+\Delta CPI_t)(1-X_t^i)$$

Where:

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year *t*–2 to the June quarter in year *t*–1.

X_t^i is the X factor for service *i* in year *t*, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of material directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

~~*Tax* is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, netting off the net present value of the reverse cash flow resulting from the depreciation of the capital contribution.~~

7.3 Security deposits and fees

In certain circumstances, we may require the payment of a security deposit or bank guarantee and may withhold a security fee from the deposit. We do this in circumstances where we consider there is a significant risk that we may not earn the estimated incremental revenue from the connection services we provide. If a security deposit is charged, we may require an amount to be paid upfront, or we may require a financial security[27] to be provided for an amount which is the lesser of:

- The incremental revenue at risk of non-recovery; and
- The incremental cost incurred by us in providing the connection service.

Under these circumstances, where the security deposit is provided as an upfront payment, we will rebate the security deposit via annual instalments, with the annual rebate being:

- Any interest earned on the security, calculated at the interest rate (cost of debt) approved by the AER for the current revenue determination; plus
- The lesser of:
    - the actual incremental revenue received from the customer for the year; or

[27] Such as a bank guarantee.

- the security deposit that was paid for that year.

We will not require a security deposit:

- For an amount that exceeds the value of the incremental revenue which is at risk of not being recovered;
- For an amount that exceeds the present value of the incremental costs incurred by us; or
- Where the total value of the network augmentation or connection asset augmentation is valued at less than $10,000.

7.4 Dispute resolution

If a connection applicant wishes to dispute our connection charges or the terms and conditions of a connection agreement, disputes are managed in accordance with our Customer Complaint and Dispute Resolution Policy and the principles of the International Standard ISO 10002. A copy of the Customer Complaint and Dispute Resolution Policy is available from our website: https://www.ausnetservices.com.au/Misc-Pages/Links/Contact-Us

We will endeavour to resolve any disputes in a timely, fair and transparent manner.

A connection applicant is entitled to refer a dispute to the AER. Information on the AER's customer connection dispute resolution process is available on its website: http://www.aer.gov.au/about-us/dispute-resolution.

Glossary

Abbreviation	Full Name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CC	Capital Contribution
CPI	Consumer Price Index
CT	Current Transformer
DUOS	Distribution Use of System
EG	Embedded Generation
ICCS	Incremental Cost Customer Specific
ICSN	Incremental Cost Shared Network
IR	Incremental Revenue
kVA	Kilovolt amperes
MSO	Model Standing Offer
PV	Photovoltaic
REFCL	Rapid Earth Fault Current Limiters
SWER	Single-wire earth return

Definitions

Alternative Control Services	A distribution service provided by AusNet Services that the AER has classified as an Alternative Control Service under the NER.
Approved Contractor	A contractor approved by AusNet Services that can provide Contestable Services.
Augmentation	Work to enlarge the distribution system or to increase its capacity to distribute electricity.
Australian Energy Regulator (AER)	The AER is an independent statutory authority that is part of the Australian Competition and Consumer Commission. The AER is responsible for the economic regulation of electricity networks in the National Electricity Market.
Basic connection service	A connection service that meets the requirements for a Basic Connection Offer as set out in Chapter 3 of this Connection Policy.
Capital Contribution (CC)	A capital contribution may be charged where a network extension, augmentation or connection assets are required for a new connection or alteration in accordance with this policy.
Codified Area	Defined under the Electricity Safety (Bushfire Mitigation) Regulations as ‘Electric Line Construction’ areas.
Connection	A physical link between a distribution system and a retail customer’s premises to allow the flow of electricity.
Connection alteration	An alteration to an existing connection including an addition, upgrade, extension, expansion, augmentation or any other kind of alteration.
Connection applicant	An applicant for a connection service who is either a retail customer; retailer or other proxy for a retail customer, or a real estate developer.
Connection application	An application made under clause 5A.D.3 of the NER.
Connection assets	Those components of a transmission or distribution system which are used to provide connection services. Connection assets are those assets required to connect an electrical installation to the shared network and are all the assets from the connection point back up to and including the network coupling point.
Connection charge	A charge imposed by a Distribution Network Service Provider for a connection service.
Connection contract	A contract formed by the making and acceptance of a connection offer.
Connection offer	An offer by a Distribution Network Service Provider to enter into a connection contract with a retail customer or a real estate developer.

Connection point	The agreed point of supply established between Network Service Provider(s) and another Registered Participant, Non-Registered Customer or franchise customer.
Connection policy	A document, approved as a connection policy by the AER under Chapter 7, Part E of the NER.
Connection service	Means either or both of the following: (a) a service relating to a new connection for premises; (b) a service relating to a connection alteration for premises.
Contestable Service	A service is contestable where it can be provided on a competitive basis. Contestable Services can be provided by AusNet Services or an Approved Contractor.
Customer	A person or entity that receives, or wants to receive a supply of electricity for a premises, or any other distribution service from AusNet Services.
Distribution Network Service Provider	A person that owns, controls or operates a Distribution Network and the associated connection assets. AusNet Services is a distribution network service provider.
Distribution system	The electrical system used to transport electricity from the high voltage transmission network connection point to distribution network users.
Distribution Use of System (DUOS) charge	The component of the network tariffs which covers costs associated with connection services and/or use of the distribution network for the conveyance of electricity.
Energy	The amount of electricity consumed by a consumer over a period of time. Energy is measured in terms of watt hours, such as kilowatt hours (kWh), megawatt hours (MWh) or gigawatt hours (GWh).
Extension	Work that involves the construction and connection of a power line or facility outside the present boundaries of the distribution network owned, controlled or operated by AusNet Services.
National Electricity Rules	Rules made under the National Electricity Law which govern the operation of the National Electricity Market.
Negotiated connection service	A connection service that is not a basic connection service or a standard connection service.
New connection	A connection established or to be established, in accordance with Chapter 5A of the NER and applicable energy laws, where there is no existing connection.
Non-registered embedded generator	An embedded generator that is neither a micro embedded generator nor a Registered Participant.
Original customer	The connection applicant who triggered the requirement and paid for the construction of an extension asset.
Pioneer scheme	A scheme to enable original customers to receive a partial refund of their capital contributions where the network extension funded by the capital contribution is subsequently used by other customers.

Real Estate Developer	A person who carries out a real estate development.
Real estate development	The commercial development of land including its development in one or more of the following ways: (a) subdivision; (b) the construction of commercial or industrial premises (or both); (c) the construction of multiple new residential premises.
Registered participant	A person who is registered by AEMO in any one or more of the categories listed in rules 2.2 to 2.7 of the NER (in the case of a person who is registered by AEMO as a Trader, such a person is only a Registered Participant for the purposes referred to in rule 2.5A of the NER). However, as set out in clause 8.2.1(a1), for the purposes of some provisions of rule 8.2 of the NER only, AEMO, Connection Applicants, Metering Providers and Metering Data Providers who are not otherwise Registered Participants are also deemed to be Registered Participants.
Standard connection service	A connection service that meets the requirements for a Standard Connection Offer as set out in Chapter 4 of this Connection Policy

FINAL DECISION

AusNet Services, CitiPower, Jemena, Powercor, and United Energy
Distribution Determination
2021 to 2026

Attachment 19
Tariff structure statement

April 2021

AUSTRALIAN ENERGY REGULATOR

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AER reference: 63599, 63600, 63601, 63602, 63603

Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to AusNet Services, CitiPower, Jemena, Powercor, and United Energy for the 2021–26 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Customer service incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Negotiating framework

Contents

19 Tariff structure statement

This attachment sets out our final decision on the Victorian electricity distributors' proposed tariff structure statements to apply for the 2021–26 regulatory control period.

A tariff structure statement applies to a distributor's tariffs for the duration of the regulatory control period. It describes:

- a distributor's tariff classes and structures
- the distributor's policies and procedures for assigning customers to tariffs
- the charging parameters for each tariff
- a description of the approach the distributor will take to setting tariff levels in annual pricing proposals.

It is accompanied by an indicative pricing schedule.[1]

A tariff structure statement provides consumers and retailers with certainty and transparency in relation to what network tariff structures will be charged to retailers for different types of consumers over the five year period to which it applies. It also explains how a distributor's tariff strategy aligns with other initiatives it is undertaking, such as the management of distributed energy resources (DER) and demand management.

Our final decision focuses upon issues unresolved after our draft decision and each Victorian electricity distributor's revised proposed tariff structure statement. We approved most elements of the initial proposals. Revised proposals dealt with most issues left outstanding after our draft decision. A small number of issues remained to be addressed with our final decision. For details of our consideration of previously settled issues, please see Attachment 19 of our draft decision for each Victorian distributor.[2] For example, most small customer tariff issues have been settled prior to this final decision.

With their revised proposed tariff structure statements, the Victorian distributors made a number of improvements to their large customer tariffs. Our final decision is to approve them. We accept that there was insufficient time to establish additional large customer tariffs between our draft decision and revised proposals being submitted to us.

Stand-alone energy storage assets and electric vehicle charging stations can, if appropriately incentivised, make significant contributions to more efficient operation of Victoria's distribution networks. To realise those benefits they must be exposed to network tariffs which signal the costs of network use at times of current or future

1 NER, cl. 6.18.1A(e).

2 As the Victorian distributors coordinated on a number of key issues we produced one draft decision attachment to cover the proposed tariff structure statements from the five distributors together. This was published as Attachment 19 under the draft decision for each distributor.

congestion on the relevant parts of the network. They should also make contributions to network cost recovery commensurate with their network use.

Our final decision is that new and emerging technologies with potentially significant new loads should face appropriate network price signals to guide their use of network assets. Without appropriate network price signals these potentially beneficial technologies could exacerbate network congestion and worsen bill outcomes for all Victorian electricity consumers.

Further improvements to the efficiency of Victoria's distribution network price signals may be made in the future. We note the Victorian networks intend to trial a number of innovative new tariffs, including for large customers. This matches a more general move across the National Electricity Market (NEM) to trial new tariffs and new technologies. We support these initiatives to inform the ongoing reform program.

Future network tariffs should further enhance opportunities for consumers to optimise their own consumption and asset use, while getting the most out of shared network assets financed by all consumers. They should also be technologically neutral, simply signalling the costs (and benefits) arising from serving the consumers' use of the network.

19.1 Final decision

Our final decision is to approve the Victorian electricity distributors' tariff structure statements with amendments that:

- ensure all consumers contribute to the recovery of the cost of operating and maintaining the electricity distribution network they use, including stand-alone (grid scale) storage assets;
- provide greater detail on tariffs to be trialled in the first year of the regulatory control period under the approved tariff structure statements; and
- simplify tariff assignment policies to support Victorian Government policy and facilitate simpler engagement between distributors and retailers.

Our broad acceptance of the distributors' revised proposals is due to the revised Victorian tariff structure statements largely aligning with our draft decision.
For example, our draft decision for the residential and small business tariff classes established:

- default assignment to the time of use tariff with the ability to opt-out to the demand or flat rate network tariff structures;
- reassignment of customers on legacy time of use, flexible and demand tariffs to the new time of use or demand equivalent;
- discounted time of use and demand tariffs relative to the flat rate to incentivise take-up of these more cost reflective options;
- state wide peaks of 3pm to 9pm for residential customers and 9am to 9pm for small business customers;

- removal of access to the flat rate network tariff for electric vehicle owners, once such customers are identifiable; and
- continued ability for customers with consumption under 160 MWh a year but demand greater than 120 kVA to access a zero demand tariff structure.

However, following engagement with the distributors we have revised our approach to accept:

- distributors may provide tariff choice to large users through tariff trials and transitional arrangements during the 2021–26 regulatory control period.

19.2 Victorian distributors' revised proposals

The Victorian distributors' revised tariff structure statements closely resemble the tariff structure statements initially proposed in January 2020. In response to our draft decision, the distributors made the following changes:

- AusNet Services aligned with other distributors in allowing solar customers to opt-out to a flat rate tariff but incentivising the choice of a cost reflective tariff through introducing a discount of 1 per cent per year relative to the flat rate.
- CitiPower, Powercor and United Energy increased the peak to off-peak ratio of the residential time of use tariffs to maintain the established ratios.
- All five distributors proposed to remove legacy residential cost reflective tariffs to focus on the coordinated choice of the new time of use, demand or flat rate tariffs for the new regulatory control period.
- All five distributors supported the Victorian Government's position that electric vehicle owners should face cost reflective tariffs to support the efficient integration of this emerging technology.[3]
- CitiPower, Jemena, Powercor, and United Energy reviewed and refined their large user peak charging windows to more closely target network conditions.[4] This included CitiPower, Jemena and Powercor adopting United Energy's incentive peak demand component into their large user tariff structure.
- CitiPower, Powercor and United Energy provided further flexibility by allowing large business customers who can demonstrate their capacity to match "the nature and extent of their usage"[5] and "nature of their connection to the network" to the small business tariff class to be reassigned to this tariff class.
- All five distributors provided greater clarity on how their tariff strategy aligned with DER integration and demand management programs over the regulatory control period, including a clear commitment to trial alternative tariffs (see Appendix B).

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3 Victorian Department of the Environment, Land, Water and Planning, *Victorian Government submission on tariff structure statements 2021–26*, 29 May 2020, p 1.

4 As AusNet Services uses a critical peak demand tariff structure targeted at five peak demand events rather than the long peak windows the other distributors initially proposed for medium and large businesses.

5 NER cl 6.18.4 outlines the characteristics that should inform the assignment of tariff classes and requires customers with similar connection and usage profiles to be treated on an equal basis.

With respect to energy storage:

- AusNet Services and Jemena adopted CitiPower, Powercor and United Energy's proposal to offer standalone batteries in their network zero priced tariffs, noting the right to an avoided transmission use of system (TUOS) rebate would need to be waived should the battery not pay tariffs.

With respect to large business customer tariffs and contrary to our draft decision, the distributors proposed:

- Not to offer large user tariff choice, but they have made a number of improvements to their proposed large customer tariffs and undertaken to support tariff trials.
- CitiPower, Jemena and Powercor proposed transitional arrangements to support implementation of their amended large user tariff in their revised proposals.
- AusNet Services undertook to consider extending its critical peak price large business customer tariff to its medium business customers in the 2026–31 regulatory control period.

19.3 Assessment approach

We assessed revised proposals against the two sets of requirements for tariff structure statements set out in the National Electricity Rules (NER).

First, the NER sets out a number of elements that an approved tariff structure statement must contain.[6] These include the structure of proposed tariffs, and the policies and procedures the distributor will use to assign customers to those tariffs.

Second, a tariff structure statement must comply with the distribution pricing principles.[7] Broadly, the pricing principles require tariffs to reflect a distributor's efficient costs. An approved tariff structure statement must have regard to the impact on customers in the transition to cost reflective tariffs.

Please refer to our draft decision for more details.[8]

19.4 Reasons for final decision

In this section, we outline our reasons for:

- requiring standalone batteries to:
    - face network price signals to guide their operation
    - contribute to the cost of operating and maintaining the electricity distribution networks they use

6 NER, cl. 6.18.1A(a).

7 NER, cl. 6.18.1A(b).

8 AER, *Draft Decision – AusNet Services, CitiPower, Jemena, Powercor and United Energy Distribution Determination 2021 to 2026 Attachment 19*, September 2020, p 19-8 to 19-11.

- approving CitiPower, Jemena and Powercor's more targeted large customer tariff peak charging windows and their adoption of United Energy's incentive demand tariff structure with a transitional arrangement
- requiring the distributors to provide further information on their intended tariff trials for the first year of the regulatory control period, in addition to plans for later years
- amending the distributors' assignment policies to clearly remove access to the flat rate network tariff for electric vehicle owners and allow retailers to request tariff reassignment to optimise their retail offers.

As previously noted, with our support, the Victorian electricity distributors retained most of their initial proposed tariff structure statements for their revised proposals. We have not provided additional analysis of:

- issues we approved and which were not changed between initial and revised proposals (e.g. the aligned residential and small business charging windows)
- elements of our draft decision which the Victorian electricity distributors adopted with their revised proposals (e.g. reassigning customers on legacy cost reflective tariffs and maintaining historical peak to off-peak ratios for small users).

Stakeholders seeking the reasons for our above decisions should refer to Attachment 19 of our draft decision.[9]

19.4.1 Tariff choice for medium and large business tariffs

United Energy's medium business customers

In its revised proposal, United Energy proposed that its medium business customers be able to opt-out to a time-of-use tariff only. We consider this is appropriate. Our final decision is to approve this element of United Energy's revised proposed tariff structure statement.

United Energy's medium sized business customers are capable of understanding time of use tariffs.[10] They may also mitigate the impact of the change in tariffs through their usage decisions, including by investing in energy storage.[11]

In its initial tariff structure statement proposal, United Energy proposed that medium business customers be assigned to a demand tariff, with the ability to opt-out to either a time-of-use tariff or a single-rate tariff.

Our draft decision was that the single-rate tariff was inappropriate, given its inability to provide a price signal to customers as to their impact on the network. Single rate tariffs do not signal the likely cost to the distributor of meeting demand during times of

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9 AER, *Draft Decision – AusNet Services, CitiPower, Jemena, Powercor and United Energy Distribution Determination 2021 to 2026 Attachment 19*, September 2020

10 NER, cl. 6.18.5(i).

11 NER, cl.6.18.5(h0(3).

greatest network utilisation.[12] Accordingly, in our draft decision we required United Energy to either incorporate cost-reflective elements (such as demand or critical peak pricing) within this tariff structure or exclude it as an opt-out alternative.

Tariff optionality for medium and large business customers

Our final decision is to approve the Victorian distributors' proposal to not offer tariff choice to large business customers and Jemena's medium business customers. We accept that, given limited time to develop and consult stakeholders on new tariff designs, the distributors were not able to introduce further choice between their initial and revised proposals.

In their initial tariff proposals, the Victorian distributors offered only one network tariff to their large business customers. This was in contrast to distributors in other jurisdictions which generally offer large business customers a choice of alternative cost reflective tariffs in addition to the default tariff.

In our draft decision we required the Victorian distributors to:

- offer their large business customers an alternative network tariff, in addition to their default tariffs, in the form of an individually calculated customer (ICC) tariff
- set out the parameters and processes they would use to develop the charging parameters and price levels of those tariffs.

We also required AusNet Services to provide its medium business customers with an opportunity for network tariff choice in addition its default critical peak demand tariff.

In their revised proposals, the Victorian distributors argued that there was insufficient time available to design and develop new site-specific tariffs. The Consumer Challenge Panel, sub-panel 17 (CCP17) supported this view, highlighting there was only a nine-week period between the release of the draft decision and development of revised proposed tariff structure statements.[13]

Jemena and the CCP17 both submitted that the provision of optionality, merely for the sake of choice, would result in customers simply selecting the cheapest tariff and not necessarily elicit a beneficial behavioural change.[14] The Energy Users Association of Australia (EUAA) doubted there was any benefit from introducing further optional cost reflective tariffs.[15]

In response to the CCP17 and EUAA, we note that when tariffs are cost reflective any reduction in a customer's network bill will derive from behaviour that reduces

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12 NER, cl. 6.18.5(f)(2).

13 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 78.

14 Jemena, *2021–26 Electricity Distribution Price Review Revised Proposal, Attachment 12-02, Tariff Structure Statement – Explanatory Document*, 3 December 2020, p. 70; CCP17, *Advice to the AER on the Victorian Electricity Distributors' Revised (Final) Regulatory Proposals for the Regulatory Determination 2021–26*, 8 January 2021, p. 78.

15 Energy Users Association of Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 11.

operational and investment costs for the network. We consider there is merit in enabling consumers to choose the tariff structures that best suit them. This is relevant to large customers just as for small customers. We note too that tariff optionality may provide the flexibility that customers need to unlock the marginal behavioural change required to realise network benefits.

While no Victorian distributor proposed an ICC tariff for their large business customers in their revised tariff structure statement, several reviewed the structure and assignment of their default large business tariff. In particular:

- CitiPower, Powercor and Jemena proposed a tariff structure consistent with that of United Energy by incorporating an incentive demand charge into their existing tariffs. This facilitates a commensurate reduction in the levels of other tariff parameters.[16]
- CitiPower, Powercor and United Energy proposed to set locational windows for their incentive demand charges to better target local network constraints.
- CitiPower, Powercor, United Energy and Jemena proposed to revise their peak charging windows.[17] [18] [19]

Following consultation with key stakeholders, including the EUAA, AusNet Services proposed no changes to the existing pricing structure and assignment policies of its critical peak demand tariffs for medium and large business customers. However it did adjust its medium business tariff peak charging window, as discussed below.[20]

EnergyAustralia submitted that the revised large business customer tariffs incorporated improved operational signals and represented an improvement on current arrangements. It submitted that the incentive tariff component and the determination of demand over a twelve-hour period provide time-based signals for storage assets to efficiently utilise spare network capacity.[21]

However, EnergyAustralia also submitted that there was further opportunity for tariffs to optimise network use, particularly for storage assets.[22]

Similarly, AGL submitted that there remains scope to further improve tariff structures for large businesses to be more cost reflective. In particular, it did not consider the measurement of maximum demand charges over wide time periods to be sufficiently cost reflective for situations where a large customer can effectively schedule its

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16 These new incentive demand charges will be introduced on a transitional basis to enable customers to adjust to the new tariff structure.

17 CitiPower, Powercor Australia and United Energy*, Tariff Structure Statement – Explanatory Document 2021–26*, 3 December 2020, pp. 17-21.

18 Jemena*, 2021–26 Electricity Distribution Price Review Revised Proposal, Attachment 12-02, Tariff Structure Statement – Explanatory Document*, 3 December 2020, p. 70; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, January 2021, p. 61.

19 Ibid.

20 AusNet Services, *Revised Tariff Structure Statement 2022–26, Explanatory Pape*r, 3 December 2020, p. 56.

21 EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021,, pp. 1-2.

22 Ibid.

maximum demand. Nonetheless, AGL submitted that dynamic locational pricing would be difficult to achieve under the existing framework.[23]

EnergyAustralia was concerned that the minimum demand charges proposed may disadvantage smaller users.[24]

The basis for our draft decision requirement for tariff optionality was to further the cost-reflectivity of large business tariffs, particularly though establishment of locational price signals. We considered ICC tariffs to be a suitable means of introducing both locational and, where necessary, more dynamic charging parameters.[25] Across other NEM regions, ICC tariffs are used to better signal to large customers the actual cost of their connection and network use.

However, we acknowledge the challenges associated with development of site-specific tariffs, and accept that it has been impractical for the Victorian distributors to incorporate ICCs within their revised proposals in the time available to them.

Jemena, United Energy, CitiPower and Powercor proposed revisions to their default large business tariffs. We consider these changes enhance the cost reflectivity of those tariffs and therefore partially meet our draft decision objectives.

While AusNet Services elected not to reform its medium and large business tariffs, we recognise the superior cost-reflective nature of its existing critical peak pricing tariffs and the dynamic signals they send about periods of network constraints.

In the absence of site-specific tariffs, we note that distributors intend to provide some flexibility and optionality for customers. For example, AusNet Services proposed to permit a review of the capacity value assigned to the capacity element of its critical peak demand tariff.[26]

Similarly, United Energy, CitiPower and Powercor proposed to enable customers to opt out of a large business demand tariff to a time of use tariff, subject to installing equipment to limit demand to 120 kVA.[27]

In addition, CitiPower, Powercor, United Energy and Jemena propose to retain the safety net, provided for under Victorian Government legislation,[28] enabling customers consuming less than 160 MWh per annum to access a tariff structure with a $0 demand component.[29] Those customers may choose a usage-based tariff regardless

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[23] AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

[24] EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 5.

[25] AusNet Service's critical peak price large customer tariff is an example of a dynamic tariff. It is not, however, locational in nature.

[26] AusNet Services, *Revised Tariff Structure Statement 2022–26, Compliance Documen*t, 3 December 2020, p. 23.

[27] CitiPower, *Tariff Structure Statement 2021–26*, December 2020, p. 14 ,Powercor, *Tariff Structure Statement 2021–26*, December 2020, p. 44, and United Energy, *Tariff Structure Statement 2021–26*, December 2020, p. 14.

[28] Advanced Metering Infrastructure (AMI Tariffs) Amendment Order 2017 Order in Council, gazetted 12 September 2017.

[29] CitiPower, *Tariff Structure Statement Explanatory Document 2021–26,* December 2020, p 21; Powercor, *Tariff Structure Statement Explanatory Document 2021–26*, December 2020, p 21; United Energy, *Tariff Structure*

of the size of their peak demand when their consumption remains below 160 MWh per annum.

Accordingly, we approve the tariffs as proposed. However, we consider that the Victorian distributors should continue to pursue further development of these tariffs, including the potential for ICC tariffs, in their 2026–31 tariff structure statements.

In this context, we note that tariff trials and demand management initiatives have been foreshadowed for the forthcoming regulatory period. These undertakings should inform the continued progress of tariff reform, particularly at the medium and large business customer level, in tariff structure statements for the 2026–31 regulatory period.

For example, all five Victorian distributors have committed to exploring alternative tariff arrangements for electrical vehicle charging stations. The evidence and learnings from these trials could be applied to other customers with similar connection and network usage, such as irrigators and medical imaging service providers.

We will work with the distribution businesses over the 2021–26 regulatory control period to support implementation of these trials.

CitiPower, Powercor and United Energy large customer minimum thresholds

Subsequent to submitting to us their revised proposed tariff structure statements, CitiPower, Powercor and United Energy noted to us that high voltage (HV) customer demand had fallen substantially, especially due to the COVID-19 pandemic, and considered these customers would be adversely impacted by the proposed thresholds for minimum chargeable demand. Accordingly, the three businesses proposed to lower the minimum chargeable demand for their:

- HV customers, from 1,000 kVA to 500 kVA
- sub-transmission customers, from 10,000 kVA to 5,000 kVA.[30]

We consider this is reasonable and have modified the CitiPower, Powercor and United Energy tariff structure statements to reflect the above changes.

Australian Energy Market Operator review of its Victorian transmission pricing methodology

Subsequent to submitting their revised proposed tariff structure statements to us, CitiPower, Powercor and United Energy separately proposed a further change. They proposed that the incentive demand charge for their sub-transmission customers be initially set to $0 in recognition of Australian Energy Market Operator's (AEMO's)

Statement Explanatory Document 2021–26, December 2020, p 21; Jemena, *Revised Regulatory Proposal, Attachment 12-01 Tariff Structure Statement*, December 2020, p 9.

30 Email correspondence to the AER, 19 February 2021.

ongoing review of the transmission pricing methodology in Victoria.[31] Once this review is completed and the final transmission tariff structures known, the distribution businesses indicated that they would reconsider this charge.[32]

We support the sub-transmission pricing structure being modified should we approve the change in AEMO's pricing methodology for transmission tariffs. However, we consider it appropriate that the tariff structure statements be amended to provide network customers with greater certainty as to how the final transmission tariff structure will impact the incentive demand charge from 1 July 2022.

In particular, we consider there should be an explicit commitment to resume the transition towards the incentive demand structure identified in the revised proposal if AEMO's pricing methodology remains unchanged. Alternatively, should AEMO move from a tariff structure focused on a limited number of peaks to one considering peaks across 365 days, the incentive demand component should remain at $0.

We have modified the tariff structure statements to reflect the above.

19.4.2 Charging windows

Reconsideration of particular peak charging windows

Our final decision is to approve the more targeted peak charging windows proposed by the Victorian distributors for their large customer tariffs. We consider the revised charging windows better reflect when networks are, or are likely to become, constrained. They also provide large customers with greater opportunity to shift their load to avoid peak charging periods, so are more likely to elicit a beneficial behavioural response from those customers.

In our draft decision we highlighted concerns with some very broad peak charging windows proposed by the Victorian distributors. We considered there to be a potential for them to inaccurately reflect when the network is under greatest strain. They may also have been too wide to send effective price signals to customers about their use of the network.

Accordingly, we suggested that the distributors consider amending these peak charging windows to make them more targeted. Except for United Energy, the distributors responded to our draft decision by tightening their business tariff peak charging windows.

Table 19.1 compares the peak charging windows proposed by the Victorian distributors in their initial proposed tariff structure statements with those in their revised proposals.

31 See https://aemo.com.au/consultations/current-and-closed-consultations/transmission-use-of-system-pricing-methodology-vic.

32 Email correspondence to the AER, 8 February 2021.

Table 19.1 Revised Peak charging windows

Distributor	Tariff/s	Draft proposed peak charging window	Revised proposed peak charging window
AusNet Services	Default medium business tariff	07:00 to 10:00 16:00 to 23:00	16:00 to 21:00
Jemena	All medium business, large business and sub-transmission tariffs	07:00 to 23:00	08:00 to 20:00
CitiPower, Powercor	Opt-in medium business tariff	07:00 to 23:00	10:00 to 18:00
United Energy	Opt-in medium business tariff	09:00 to 21:00	09:00 to 21:00

Source: AER analysis of data provided by distribution businesses.

Based on its analysis of recent network utilisation data, AusNet Services proposed that, for its medium business tariff:

- the morning peak be removed
- the evening peak be narrowed

with these windows to take effect from 1July 2023.[33]

The EUAA supported the single peak charging window and its delayed introduction.[34]

Jemena provided data to support a narrowing of the peak window for its large business tariffs, proposed in conjunction with the introduction of a summer demand incentive charge, discussed in section 19.1.1 above. This decision was taken following consultation with its Customer Council.[35]

CitiPower proposed to significantly narrow the peak charging window for its opt-in medium business tariff, but did not provide any supporting analysis.[36]

United Energy elected not to revise the peak charging window for its opt-in medium business tariff.

We approve the peak charging windows contained in the Victorian distribution businesses' revised tariff structure statement proposals.

Powercor's large customer charging windows

In our draft decision, we noted Powercor proposed the same peak and demand charging windows for its large business and sub-transmission tariffs as CitiPower.

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33 AusNet Services, *Revised Tariff Structure Statement 2022–26*, Explanatory Paper, 3 December 2020, pp. 56-63.

34 Energy Users Association of Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 11.

35 Jemena, *2021–26 Electricity Distribution Price Review Revised Proposal, Attachment 12-02, Tariff Structure Statement – Explanatory Document,* 3 December 2020, p. 64.

36 CitiPower, Powercor Australia and United Energy, *Tariff Structure Statement – Explanatory Document 2021–26*, 3 December 2020, p. 7.

We sought clarity from Powercor as to how its charging windows reflect the periods when its network is most heavily utilised.

In its revised tariff structure statement proposal Powercor proposed to adopt the same revised tariff structure as CitiPower and United Energy. It proposed that identical peak and demand charging windows would apply across all three distribution businesses. However, Powercor also proposed that windows for incentive demand charges be dependent on customer location, determined on the basis of an analysis of zone substation peak demand times across the network.

We accept the locational-based charging arrangements proposed will more effectively contribute to the recovery of network costs at times of peak demand. We approve Powercor's proposed approach.

19.4.3 Tariff treatment of grid scale storage

Our final decision is that stand-alone energy storage assets, such as batteries but potentially also other energy storage technologies, that provide services other than solely network support, must be assigned to tariffs according to the usual tariff class assignment criteria. It is appropriate that such assets contribute to network cost recovery and see network price signals to guide their operation.

Ownership of energy storage assets should not be the basis for differential tariff treatment. Capital investment and operational decisions for these assets should be based on a cost-reflective price signal, determined by the underlying use of network services, connection arrangements and the relevant approved tariff class structure. In other words, if the asset falls into a particular tariff class, it should be exposed to the same network tariffs as other customers in that tariff class, whether owned by a distributor, its affiliate or a third party.[37]

In their initial proposed tariff structure statements, all Victorian distributors proposed that any grid-scale battery they owned be exempt from network tariffs. However, their proposed tariff treatment differed for batteries owned by other parties:

- CitiPower, Powercor and United Energy proposed to exempt batteries they do not own from a network tariff under particular circumstances, including where:
    - there is only generation or no other load at the site
    - the battery is to be operated to the net benefit of the distributor's customers
- AusNet Services and Jemena proposed to continue to treat batteries in accordance with their standard tariffs to reflect the demand they place on the network, with no exemptions
- Jemena also noted it was considering a tariff specific to customers who provide network benefits, including battery owners.

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[37] Clauses 6.18.4 (a) (2) and (3) of the NER require all load to be treated the same, regardless of the presence of microgeneration. We believe that this requirement extends to treating batteries in a manner consistent with their use of the network.

We did not make a draft decision in relation to this matter, given the lack of information provided by the distributors. We also took into account the ongoing Australian Energy Market Commission (AEMC) review of AEMO's Integrating Energy Storage Systems into the NEM rule change proposal (the AEMO rule change proposal).[38]

At the time of our draft decision, we considered the rule change process would provide clearer policy direction on tariffing of grid scale storage, even if the AEMC would not make its final determination until after the Victorian tariff structure statements were finalised. We believed that a change in policy was likely and that transitional arrangements would be appropriate to accommodate new rules.

In that context we identified four interim pricing options, seeking stakeholder comment on these and any alternative courses of action.

In response to our draft decision, all five Victorian distributors proposed to exempt grid-scale batteries from network tariffs if the asset is owned by either:

- the distributor and installed to manage the distribution network, or
- another party and operated to the 'net benefit' of network customers.

In the latter case above, the asset owner would forego avoided TUOS payments.[39]

On 3 December 2020, subsequent to the release of our draft decision, the AEMC extended the period of time for it to make a draft determination on the AEMO rule change proposal to 29 April 2021.[40]

Shortly afterwards, the AEMC published an options paper, seeking further stakeholder engagement on alternatives to AEMO's proposed solutions, which it considered may better align with the Energy Security Board's (ESB) post-2025 market design reforms, particularly the transition to two-sided markets.[41]

To the extent the AEMC's options paper and communication to date have not addressed:

- the lack of clarity in the NER as to the appropriate charging arrangements for energy storage systems, and
- the potential investment distortions arising from differential charging arrangements at the transmission and distribution level.

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38 AEMO, *Electricity Rule Change Proposal – Integrating Energy Storage Systems into the NEM*, August 2019, p.20. Amongst other issues raised, AEMO argued there was a need for the NER to clarify whether DUOS and TUoS charges should apply to energy storage systems (including grid-scale batteries). AEMO argued that the current ambiguity in the NER means they are interpreted and implemented differently for each energy storage system.

39 CitiPower, *Tariff Structure Statement 2001-2026*, December 2020, p. 14; Powercor, *Tariff Structure Statement 2001-2026*, December 2020, p. 14; United Energy, *Tariff Structure Statement 2001-2026*, December 2020, p. 14; AusNet Services, *Revised Tariff Structure Statement 2022–26 – Compliance Document*, December 2020, pp. 23-4; Jemena, *Revised Regulatory Proposal, Att. 12-01 Tariff Structure Statement*, December 2020, p. 18.

40 See https://www.aemc.gov.au/news-centre/media-releases/extra-time-have-your-say-integrating-storage.

41 AEMC, *Options Paper - National Electricity Amendment (integrating Energy Storage Systems into the NEM) Rule 2021*, 17 December 2020, available at https://www.aemc.gov.au/sites/default/files/2020-12/Integrating%20energy%20storage%20-%20Options%20paper.pdf.

It is unlikely that the AEMC's final determination on the AEMO rule change proposal will conclusively resolve these particular matters. Nor is it likely to provide a change in the policy positions which inform the operation of the NER.

Accordingly, in the absence of new rules or additional guidance at this time, our final decision on battery pricing will likely apply for the duration of the 2021−26 regulatory control period, rather than be an interim one as we previously considered.

In submissions on our draft decision, stakeholders emphasised the importance for the tariff treatment of batteries to be consistent for all asset owners. Firm Power submitted that allowing the distributors to exempt their own batteries while proposing a different tariff treatment on others was unfair, would stymie market development and likely to lead to a worse outcome for consumers.[42] EnergyAustralia submitted that such an arrangement would be incongruous with the objective of optimising the efficient use of storage assets.[43]

We agree that asset ownership should not be a criterion for the provision of exemptions from network tariffs. To do so would hinder investment in storage technology.

All Victorian distributors proposed that storage devices they own be exempt from network tariffs where the assets are used solely for network management purposes (that is, where storage devices are contributing to the provision of standard control services only). We agree that in this context, a grid-scale battery is simply another element of regulated infrastructure providing regulated services. The regulatory framework governing these assets would be the same as for the poles and wire infrastructure.

Any plan for a distributor-owned battery to provide non-regulated services, in the wholesale market for example, would be subject to an AER ring-fencing assessment with a view to ensuring these services cannot be provided at a competitive advantage. In this case, the ring-fenced portion of the battery providing non-network services would not be considered to be part of the distributor's regulated asset base and it would be subject to network charges consistent with other assets having a similar connection to, and use of, the network.

Where a battery is owned by another party, all distributors proposed a tariff exemption where that asset is provided to the 'net benefit' of network customers. However, the proposals were silent as to how distributors would define or measure 'net benefit'.

We are concerned that this exemption criterion is not expressed in terms of transparent benchmarks which can be easily verified. In the absence of clarity, there is potential for inconsistent application across the jurisdiction, and even within the same network. There is also potential that any network charges that the distributor determines payable would not be cost reflective.

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42 Firm Power, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

43 EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 4.

The distributors also proposed that batteries receiving an exemption from network charges be required to waive their entitlement to avoided TUOS. However, EnergyAustralia submitted that this was not appropriate.[44]

Firm Power submitted that in the absence of consistent charging arrangements for distribution and transmission networks, storage assets will become concentrated in the transmission system, reducing the value of this technology in providing non-network services and in alleviating constraints in the distribution system.[45]

In our draft decision, we acknowledged the potential distortionary impact on investment that arises from different charging arrangements at the transmission and distribution levels. It is our view that this matter needs to be considered through broader policy decision-making in the context of ongoing reforms to the NEM.

We note the AEMC has foreshadowed that, during 2021, it will consult with stakeholders on potential changes required to the regulatory framework to support the efficient integration of distributed energy resources, including community batteries.[46] During the course of this review, charging arrangements for front of meter storage may be considered more generally in the context of the ESB reforms and the increasing uptake of this technology.[47]

Prior to this current regulatory review, distributors in other NEM jurisdictions did not propose specific pricing arrangements for grid-scale batteries as part of their tariff structure statements. If the revised proposals by the Victorian businesses were adopted, battery pricing arrangements in Victoria would be different to those elsewhere in the NEM despite operating in the same broader policy and regulatory framework.

Victorian Community Organisations submitted that a consistent regulatory pricing approach among the Victorian networks should be adopted.[48] We agree, but consider regulatory consistency should extend to all distribution networks across the NEM for the duration of this second round of tariff structure statement decisions, or until a clear policy decision to change the regulatory framework is made.

To this end, our final decision is to not approve the revised proposals for grid scale storage from the Victorian distributors. Instead we will maintain the status quo with battery capacity that provides non-network services being assigned to tariff classes and structures in the same manner as any other customer with a similar connection to and use of the network. To be clear, the portion of a battery providing network support services is exempt from network tariffs in the same way that any other asset providing standard control services is exempt. This approach is applicable to batteries, or any storage assets, whether owned by a distributor, its affiliate, or a third party.

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44 EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp. 3-4.

45 Firm Power, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

46 Australian Energy Market Commission, *Electricity network economic regulatory framework 2020 review*, Final report, 1 October 2020, p. 42.

47 Energy Security Board, *Post-2025 market design directions paper*, January 2021, p. 78.

48 Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 31.

We anticipate specific pricing for grid-scale batteries may be a feature of the pricing reforms in the third round of tariff structure statement assessments, given the nature of the policy and regulatory reforms currently underway. As more grid-scale batteries are integrated into distribution networks, electricity distributors are likely to identify innovative ways to reflect the locational and dynamic costs of serving customers. This may result in alternative pricing structures, particularly if they are associated with differentiation in the use of network services by customers currently in the same tariff class.

In this context, Origin Energy submitted that it supports the distributors' proposals to adopt tariff trials in the 2021−26 regulatory period to better inform future tariff strategies.[49]

19.4.4 More detail required for tariff trials

Tariff trials in the first year of the regulatory period must be included in the tariff structure statement, However distributors have discretion to introduce further trials outside of their tariff structure statements in years two to five of the regulatory period under the sub-threshold tariff arrangements.[50] We have provided further guidance on the framework governing tariff trials on our network tariff reform webpage.[51]

The Victorian distributors intend to undertake a number of trials (both tariff and non-tariff) over the coming regulatory period. This is a constructive way to manage uncertainty arising from rapidly changing consumer preferences, activities, technologies, and changes in the broader regulatory framework.[52] Trials are also a useful way to improve the evidence base to inform future tariff strategies while managing the impact on consumers.

Proposed trials range from coordinated efforts to explore innovative charging arrangements for electric vehicle charging stations to tariffs for specific community battery projects. However, the details for many potential trials are still being developed. Most will not occur in the first year of the 2021–26 regulatory control period.

Only CitiPower, Powercor, and United Energy intend to introduce tariff trials in the first year, in addition to Powercor continuing the Newstead trial.[53] Through the development of tariff trials they have been engaging with stakeholders to explore tariff trials relating to:

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49 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

50 NER cl. 6.18.1C.

51 See https://www.aer.gov.au/networks-pipelines/network-tariff-reform.

52 In the 2021–26 regulatory period the AEMC will make decisions on a number of points the ability of distributors to charge for exports, the treatment of battery storage in the regulatory framework. The ESB will also deliver their guidance for the energy system post 2025 which may have implications for the role of distributors during this period as well.

53 CitiPower, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 11; Powercor, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 11; United Energy, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 11.

- two dynamic domestic electric vehicle tariffs in collaboration with retailers across the three networks; and
- an ARENA funded trial of 40 small, distributed batteries across the United Energy network.

Additionally, since submitting their revised proposed tariff structure statements in December 2020, CitiPower, Powercor, and United Energy have advised us of further trials in development:

- engaging with the electric vehicle public charging industry on alternative tariffs and services;
- supporting the Victorian Government's neighbourhood battery initiative; and
- engaging with the Yarra Energy Foundation community battery project in CitiPower's network.

AusNet Services and Jemena will only trial tariffs under the sub-threshold provision (i.e. in years two to five) as they will initially focus on broader DER initiatives. For AusNet Services this includes supporting ARENA funded efforts to explore orchestration of electric vehicle charging and to trial a DER marketplace in collaboration with AEMO (Project EDGE).[54] Jemena will focus on exploring the required information and systems necessary to identify and communicate DER constraints in its network through its Future Grid program.[55] CitiPower, Powercor and United Energy also have broader DER initiatives through their Future Network program.

We appreciate the distributor's engagement with us on their intended trial arrangements. But we require greater detail on tariff structures and their strategy for pricing these tariffs to approve their inclusion in CitiPower, Powercor and United Energy's final tariff structure statements. We provided similar guidance to Ausgrid on its proposed placeholder tariffs.[56] While the trial tariffs differ in that they would not become part of the standard tariff offering, we require more detail to allow these tariffs to be included in the approved tariff structure statements.

A complication to detailing tariff structures is that these distributors are still negotiating the details with the retailers and community groups they are collaborating with. For example, the agreement between CitiPower and the Yarra Energy Foundation was only announced on 27 January 2021. The final approved tariff structure statement has been edited to include information about the agreed arrangements to date, the distributors' intended structures, pricing methodologies, and potential changes in future years. The latter will be subject to ongoing negotiations.

[54] AusNet Services, *Revised regulatory proposal, Tariff Structure Statement Compliance Document*, December 2020, p 24 -25.

[55] Jemena, *Revised Regulatory Proposal, Att 04-01 Response to the AER's draft decision – Capital expenditure*, December 2020, p 36.

[56] AER, *Final Decision Ausgrid 2019 to 2024 Attachment 18*, April 2019, pp. 18-15 to 18-16.

We have also provided clarification that the trials detailed in tariff structure statements apply to the first year of the regulatory period only. Any continuation of these trials in future years will need to occur under the sub-threshold tariff provisions. To align these requirements, we added to tariff structure statements a commitment by distributors to keep revenue recovered by trial tariffs within the 0.5 per cent set by the NER for sub-threshold tariffs.

19.4.5 Clear tariff reassignment to support further reforms

The tariff structure statement must outline how the distributors will:

- assign customers to tariff classes
- assign customers to the tariffs within that tariff class.[57]

The NER requires all distributors to treat customers with the same connection and usage profile on a similar basis.[58]

The distributors responded to our draft decision request for greater clarity on their definition of tariff classes. For example, Jemena explained the use of 120 kVA to differentiate between small and medium businesses, relates to the maximum capacity an overhead service cable can supply.[59] CitiPower, Powercor and United Energy also made provisions to allow customers who change their connection and usage profile to move between tariff classes. Further detail on tariff class assignment is provided in Appendix A.

We require two amendments to ensure the policies for assigning customers to tariffs within their tariff class align with the requirements of the NER:

- electric vehicle owners, when identified by the relevant network, will no longer have access to flat rate network tariffs; and
- retailers can request tariff reassignment from distributors to help optimise their portfolios while consumers retain control over their retail offer.

The Department of Environment, Land, Water and Planning (DELWP) requested the distributors' assignment policies be amended so that electric vehicle owners are assigned to the new time of use (ToU) without access to the flat rate tariff.[60]
We supported this proposal in our draft decision. The distributors' revised proposals require amendments to clearly implement this policy. Once electric vehicle owners can be identified (e.g. through the creation of a register):

- AusNet Services proposed to assign these customers to the new ToU structure[61]

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[57] NER cl. 6.18.1A(a)(1) and NER cl. 6.18.1A(a)(2).

[58] NER cl. 6.18.4.

[59] Jemena, *Revised regulatory proposal, Att 12-01 Tariff Structure Statement*, December 2020, p 13.

[60] Victorian Department of the Environment, Land, Water and Planning, *Victorian Government submission on tariff structure statements 2021–26*, 29 May 2020, p 1.

[61] AusNet Services, *Revised regulatory proposal, Tariff Structure Statement Compliance Document*, December 2020, p 27.

- Jemena stated it may seek to assign these customers to the new ToU structure[62]
- CitiPower, Powercor and United Energy proposed to align their assignment policies with the applicable Victorian Government Order.[63]

None of the distributors proposed to remove electric vehicle customer access to the flat network tariff.

Load from electric vehicle charging presents a challenge and an opportunity for distributors. With appropriate price signals the load for charging these vehicles can contribute to addressing emerging minimum demand issues. But inappropriate price signals mean these new loads may contribute to new network constraints requiring expensive additional investment to resolve. Tariff assignment policies should reflect these considerations. Hence our final decision is to make clear that electric vehicle owners may not access flat tariffs.

With respect to the decision as to which network tariff customers are assigned to, retailers remain the focus of network tariff reassignment processes. Retailers should be free to package network costs up with wholesale and other costs, in ways of their choosing to compete for customers.

The Victorian Default Offer regulatory intervention requires retailers to maintain a flat retail tariff offer.[64] Customers assigned to a cost reflective network tariff will retain access to a flat retail tariff should they prefer that option. Consumers are also supported through a number of complementary measures, such as subsidised in-home displays through the Victorian Energy Upgrades Program and comparison data from Victorian Energy Compare.

While the customer impact principles remain central to network tariff reform, distributors should not try to pre-empt the retail market outcome. Distributors should provide network price signals to inform the development of retail offers.[65] As discussed above, distributor's tariff assignment policies should focus on retailers. However, revised proposals were either unclear on this point or explicitly required customer consent for tariff reassignment:

- AusNet Services’ revised proposal appears to only allow the retailer to request an alternative network tariff at the customer's instruction;[66]
- CitiPower, Powercor and United Energy did not explicitly state the process by which reassignment can be requested by the retailer or customer;[67] and

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62 Jemena, *Revised regulatory proposal, Att 12-01 Tariff Structure Statement*, December 2020, p 9.

63 CitiPower, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 4; Powercor, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 4; United Energy, *Revised regulatory proposal, Tariff structure statement*, December 2020, p 4.

64 Victorian Default Offer Order in Council, gazetted 30 May 2019.

65 AER, *Draft Decision – AusNet Services, CitiPower, Jemena, Powercor and United Energy Distribution Determination 2021 to 2026 Attachment 19*, September 2020, pp. 19-18 to 19-19.

66 AusNet Services, *Revised regulatory proposal, Tariff Structure Statement Compliance Document*, December 2020, p 17.

- Jemena's revised proposal stated that the retailer, or a third party with authorisation from the customer, may request reassignment to a different tariff.[68]

We have modified the Victorian distributors' tariff assignment policies to clarify that tariff reassignment may be requested by retailers.

19.4.6 Long run marginal cost methodology

We consider the methods the Victorian distributors used to estimate long run marginal cost (LRMC) contribute to compliance with the pricing principles for direct control services (pricing principles).[69] We consider the Victorian distributors have achieved an appropriate balance between:[70]

- the benefits of using methods that better represent the concept of LRMC; and
- the costs those measures impose (information and administrative requirements).

The revised proposed tariff structure statements of CitiPower, Powercor and United Energy maintained their initial proposed approaches to estimating LRMC. As a result they also retained the LRMC estimates from their initial proposals.[71]

As with our draft decision, we commend CitiPower, Powercor and United Energy for advancing the development of LRMC estimation methods in the NEM with their approach.[72] CitiPower, Powercor and United Energy used the marginal incremental cost approach, which operates in principle like the Turvey approach, to produce LRMC estimates for each zone substation in their respective networks. We consider these are significant advances on the average incremental cost approach they used in their tariff structure statements for the 2016–21 period.

In our draft decision we noted that we considered the approach of AusNet Services and Jemena to estimating LRMC largely contributed to compliance with the pricing

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67 For example, page 5 of CitiPower's revised Tariff Structure Statement simply states "customers can opt out" and provides "tariff options" without providing an indication of the process for doing so.

68 Jemena, *Revised regulatory proposal, Att 12-01 Tariff Structure Statement*, December 2020, p 8; Jemena, *Revised regulatory proposal, Att 12-01 Tariff Structure Statement, Attachment A - Assignment and reassignment policy*, December 2020, p 11.

69 When assessing the Victorian distributors' LRMC estimation methods for compliance with the pricing principles, we had regard to our assessment framework for this second round of tariff structure statements (see appendix C of our previous distribution determinations: https://www.aer.gov.au/networks-pipelines/network-tariff-reform).

70 NER, cl. 6.18.5(f).

71 CitiPower, *Revised regulatory proposal - 2021–26 - APP06 - Tariff structure statement*, December 2020, pp. 20–23; CitiPower, *APP06 - Tariff structure statement technical*, 31 January 2020, pp. 21–24; Powercor, *Revised regulatory proposal - 2021–26 - APP06 - Tariff structure statement*, December 2020, pp. 20–23; Powercor, *APP06 - Tariff structure statement technical*, 31 January 2020, pp. 22–25; United Energy, *Revised regulatory proposal - 2021–26 - APP06 - Tariff structure statement*, December 2020, pp. 20–23; United Energy, *APP06 - Tariff structure statement technical*, 31 January 2020, pp. 21–24.

72 AER, *Draft decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 19: Tariff structure statement*, September 2020, pp. 37–41.

principles. This was particularly the case with regard to the estimation methods and forecast horizon they used to derive their LRMC estimates.[73]

With our draft decision we encouraged both AusNet Services and Jemena to explore ways to incorporate replacement expenditure (repex) into their LRMC methods for their revised proposals.[74] Below, we set out our assessment of this aspect of AusNet Services' and Jemena's LRMC revised tariff structure statement estimation methods.

Incorporation of repex into LRMC

AusNet Services

We are satisfied AusNet Services' decision to exclude repex as an input into its LRMC estimation method is appropriate at this stage of tariff reform. We are satisfied incremental demand is not a driver of AusNet Services' forecast repex for its 10-year forecasting horizon. AusNet Services' forecast repex therefore does not represent marginal cost, the cost of an incremental change in demand, and so should not be included as an input into LRMC estimates.

AusNet Services stated it excluded repex from its LRMC calculations because forecast changes in demand or energy consumption are not drivers of its repex forecasts. Rather, condition and risk factors (unrelated to the loads placed on the asset) are the principal drivers.[75] We are satisfied that excluding repex provides for AusNet Services' LRMC estimates to be consistent with the concept of 'marginal costs'. We note, however, that these issues are complex − as discussed below in relation to Jemena.

We encourage AusNet Services to continue exploring, in future tariff structure statements, ways to incorporate repex into their LRMC method to the extent that repex is driven by increased demand or patterns of usage of the network.[76]

In response to our draft decision, AusNet Services committed to giving further consideration to the inclusion of repex in future assessments of LRMC.[77]

Jemena

While we accept Jemena's LRMC estimation method, we consider the repex Jemena included in its estimation method may be inconsistent with the definition of long run marginal cost.[78] Incremental demand does not appear to be a driver of Jemena's forecast repex for its 10-year forecasting horizon. Such repex therefore would not represent marginal cost, the cost of an incremental change in demand. However, we

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73 AER, *Draft decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 19: Tariff structure statement*, September 2020, p. 41.

74 AER, *Draft decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 19: Tariff structure statement*, September 2020, pp. 37–41.

75 AusNet Services, *Tariff structure statement 2022–26: Explanatory paper*, January 2020, p. 66; AusNet Services, *Revised tariff structure statement 2022–26: Explanatory paper*, 3 December 2020, p. 54.

76 AER, *Draft decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 19: Tariff structure statement*, September 2020, pp. 37–41.

77 AusNet Services, *Revised tariff structure statement 2022–26: Compliance document*, 3 December 2020, p. 25.

78 NER, chapter 10.

recognise that these issues are complex and that another view may also be reasonable.

Jemena's revised tariff structure statement maintained its initial approach to estimating LRMC and the resulting LRMC estimates.[79] That is, Jemena retained in its LRMC estimate the repex that our draft decision asked to be removed.

Jemena stated that the repex it incorporated in its LRMC estimate would only reflect changes in demand if it also involves a resizing of the relevant assets.[80] Jemena therefore included repex in its LRMC calculations where this adds capacity to the network.[81] Further, Jemena stated it included only "the incremental capex above (or below) what a like-for-like capex cost would be".[82]

From this description and from Jemena's LRMC model, it remains unclear to us whether the repex Jemena included in its estimation method represents marginal costs. For example, Jemena's LRMC model described the drivers of its principal repex inputs as "routine (repex/connections)".[83] Jemena further described such expenditure as "non-augex".[84] This suggests asset condition and age, rather than changes in demand, are the principal drivers of Jemena's repex inputs. Hence, any resizing of assets may be a result of replacing assets with the modern equivalent, and not due to forecast changes in demand. These issues are, however, matters of nuance.

We accept that the distinction between enhanced capacity driven by demand and the same enhancements driven by replacement of aged assets with modern equivalents may be marginal. The additional capacity Jemena's assets achieve opportunistically through asset replacements may become necessary to meet growing demand beyond its LRMC forecast period.

So we retain our view that the repex included in Jemena's LRMC estimate may be inappropriate. However, our final decision is to not require Jemena to amend its method for estimating long run marginal costs for the 2021–26 regulatory control period. We consider doing so may provide only incremental benefits and would require significant changes to its tariff proposal. The basis for such changes may also, reasonably, be the subject of differing views.

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79 Jemena, *Revised regulatory proposal: Att 12-01 Tariff structure statement for 1July 2021 to 30 June 2026*, December 2020, pp. 21–22; Jemena, *Att 08-01 Tariff structure statement for 1 July 2021 to 30 June 2026*, 31 January 2020, pp. 19–20.

80 Jemena, *Revised regulatory proposal: Att 12-02 Tariff structure statement - Explanatory document for 1July 2021 to 30 June 2026*, December 2020, p. E-2.

81 Our draft decision stated Jemena did not include repex as an input into its LRMC calculations because Jemena's LRMC model did not include expenditure classified as "Replacement" under the AER reset RIN categories (see Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'Capex calculations'!B138:U171). However, it appears Jemena considers expenditure classified as "Connections" under the AER reset RIN categories as repex for LRMC estimation purposes (see Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'Capex calculations'!B116:U119).

82 Jemena, *Revised regulatory proposal: Att 12-02 Tariff structure statement - Explanatory document for 1July 2021 to 30 June 2026*, December 2020, p. E-2.

83 Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'Capex calculations'!E116:U119.

84 Jemena, *Att 08-03: Long run marginal cost model*, 31 January 2020, 'Capex inputs'!N:N.

We encourage Jemena to reassess its approach to including repex in its LRMC estimates for its 2026–31 tariff structure statement proposal, as we discussed in our draft decision.[85]

19.4.7 Stakeholder submissions

We received several stakeholder submissions on the Victorian electricity distributors' revised proposed tariff structure statements. Submissions generally supported the distributors' revised proposals but noted that tariff structures and strategies can continue to improve. Key themes in the submissions included:

- support for progressing network tariff reform and better communication of tariff strategies,
- large consumers want distributors to keep exploring tariff structures,
- the emerging electrical vehicle industry needs to be considered further.

Support for progressing network tariff reform and better communication of tariff strategies

Stakeholders supported the distributors' proposed approach to progressing network tariff reform over the 2021–26 regulatory period. This included support for more cost-reflectivity for small and large user tariffs, tariff trials to inform future strategies and the integration of tariffs with distributors' DER policies and demand management measures.[86] However, stakeholders sought better understanding of longer term tariff strategies, how they will be implemented in the future, and how consumers will be impacted.[87] Stakeholders accepted that network tariff reform is an iterative process that will require ongoing support and engagement.

General support for more cost-reflective residential and small business tariffs

Stakeholders supported increased cost-reflectivity for residential and small business consumers. They supported uniformity and simplicity in tariff structures between the distributors to ensure that consumers can respond to more cost-reflective price signals. Stakeholders also want to understand how changes to tariff structures, such as increased fixed charges, impact residential and small business consumers.[88]

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85 AER, *Draft decision: AusNet Services, CitiPower, Jemena, Powercor, and United Energy distribution determination 2021 to 2026: Attachment 19: Tariff structure statement*, September 2020, pp. 37–41.

86 For example see: Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12.; Spencer&Co report, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 17.; Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2;

87 For example see: Red Energy and Lumo Energy (Red and Lumo), *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12.

88 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 29.

Stakeholders supported discounting cost reflective tariffs compared to the flat rate structure to encourage take up.[89] The CCP17 suggested further analysis regarding the benefits and downsides of discounting one tariff could be considered.[90] However, Energy Consumers Australia (ECA) commended the distributors for undertaking detailed impact analysis.[91] Both stakeholders supported the distributors taking informed steps to progress network tariff reform. Stakeholders also supported reassigning consumers on residential legacy ToU tariffs to further progress network tariff reform and simplify the structures for small users.[92] Stakeholders noted their support was informed by the provision of choice, including allowing consumers to opt out to a flat tariff.[93]

In our draft decision we outlined our support for aligning residential and small business tariff strategies and progressing network tariff reform. We also encouraged distributors to reassign customers currently on legacy cost reflective network tariffs.[94] The distributors adopted our suggestions and made no other material changes to their small business and residential tariffs. The distributors received strong stakeholder support for these actions and we maintain our support for them.

The CCP17 suggested it would be worth further exploring the role of networks in protecting vulnerable consumers.[95] While the CCP17 accepted that the final impact on customers is considered to some extent through the pricing principles, it proposed a greater focus on how retailers were packaging their network charges into their offers. In this context the CCP17 expressed disappointment that our draft decision referenced Victorian Government policies such as the Victorian Default Offer. The CCP17 went on to express support for a communication and education program to assist customers in understanding and responding to cost reflective tariffs.

[89] AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 77; Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 11

[90] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 77.

[91] Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12.

[92] Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 29; Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 1.; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 76.

[93] Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12; Red Energy and Lumo Energy (Red and Lumo), *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 29.

[94] AER, *Attachment 19: Tariff structure statement | Draft decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy 2021–26*, September 2020, section 19.4.1,

[95] CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 77.

In contrast to the CCP17, other stakeholders submitted that complementary policies under state based legislation expressly should be considered, including the Victorian Default Offer.[96]

Our position is that network tariffs and the associated reform program can and do take into account impacts on vulnerable consumers. Typically this is through the consideration of estimates of customer impacts associated with reassigning customers from one tariff structure to another. We and the networks put significant emphasis on customer impact assessments when designing and assessing tariff structures. However, this analysis is necessarily undertaken at a high level.

While administering the NER pricing principles under which tariff reform is delivered, we must also be mindful of the broader regulatory framework which determines the role of distributors.

Our guidance to AusNet Services advised that delivery of customer hardship initiatives is the responsibility of retailers, not distributors, and lists existing protections for vulnerable consumers.[97] We continue to hold this view. The concerns raised by the CCP17 in this regard are better directed towards the retail sector, associated parts of the NER, and towards jurisdictional governments with capacity to introduce complementary measures. And as described in our draft decision, a number of complementary measures administered by jurisdictional governments directly bear on customers' experience of network tariff reform. In our view it is appropriate for our tariff structure statement assessments to take such complementary measures into account.

On the specific remedy identified by the CCP17; a communication and education program, we note DELWP has initiated consultations with a number of stakeholders including distributors, retailers and ECA to consider this further.

More generally our view is that the primary responsibility for liaising with customers falls upon retailers. It is retailers who package network tariffs with other costs and pass those through to customers. Retailers determine which network price signals are passed through and which are not. And it is retailers who must manage wholesale market and network pricing risk. To the extent that other parties, including jurisdictional governments, are inclined to become active in this space we are supportive. We note though that there is potential to confuse customers with messaging about cost reflective tariffs, if customers are not exposed to those price signals.

Red and Lumo Energy submitted that it wanted a better understanding of how network tariff strategies interact with obligations placed on retailers by the Victorian government

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96 The VCO recognise that the VDO exists to protect vulnerable consumers. Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 29.

97 AER, *AusNet Services Trial – AER Staff Guidance Note 7: Customer Hardship*, 29 August 2019. <https://www.aer.gov.au/system/files/AER%20-%20AusNet%20Trial%20Staff%20Guidance%20Note%207%20-%20Customer%20hardship%20-%2020%20August%202018.pdf>.

such as the Victorian Default Offer.[98] The Victorian Default Offer price is set by the Victorian government and retailers are required to make it available to consumers.

In response to Red and Lumo Energy, we note that it is not within the distributors' scope to consider the potential risk placed on retailers by having to provide a standing offer to end users. As noted above, retailers manage a number of different risks, such as wholesale energy price volatility, in developing their retail offers. The proposed arrangements are consistent with Recommendation 14 of the Australian Competition and Consumer Commissions'' Retail Electricity Price Inquiry. This is for proposed mandatory assignment of retailers to cost reflective network pricing, with a requirement for retailers to continue to offer a flat rate option for consumers.[99]

As we stated in our draft decision, network tariff reform is targeted at retailers. They may manage network price signals by offering customers insurance style flat tariffs, pass network prices through to end users, or offer 'prices for devices' style offers. [100] The Baringa report we commissioned, found that retailers can create value for end users by responding to network price signals through 'prices for devices' retail offers.[101] We encourage retailers to continue to innovate to access this value through helping consumers shift and reduce their load, including through drawing on energy efficiency initiatives.[102]

Support for continued development of tariff strategies

Stakeholders acknowledged that tariff strategies have improved but can continue to be refined. For instance, ECA supported the further action distributors have taken to increase cost reflectivity but suggested greater narrative on the purpose and intended outcomes of the tariffs is still required.[103]

Stakeholders supported the improvements distributors have made by including clearer integration of DER and demand management initiatives with their tariff strategies. They appreciate that this is an evolving and important area but consider more can be done to better align and communicate the interlinkages between these initiatives and tariff strategies.[104]

We acknowledge that the distributors have made greater efforts to communicate these strategies, and this is the first time the relationship between demand management and

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98 Red Energy and Lumo Energy (Red and Lumo), *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 2-3.

99 ACCC, *Retail Electricity Pricing Inquiry – Final Report*, June 2018, pp 187 – 188.

100 AER, *Attachment 19: Tariff structure statement | Draft decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy 2021–26*, September 2020, section 19.4.1,

101 Baringa, *Value of optimised flexible DER*, July 2020.

102 For example, the Victorian Energy Upgrades program provides financial support for households to access more energy efficient household appliances and retailers could help consumers access these programs.

103 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 11 - 12.

104 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 70.

tariffs has been given specific consideration in our final decision. The interlinkages between DER expenditure, demand management strategies and tariff strategies are explored further in Appendix B.

Stakeholders also supported further consideration of tariffs for grid-scale storage. In our draft decision, we did not make a decision on grid-scale storage given there was an expectation that the AEMC would provide a policy direction through the Integrating Energy Storage Rule change. Instead, we asked for stakeholder feedback on tariff treatment of batteries based on four options we outlined on the basis of the expected policy direction.[105] Firm Power, EnergyAustralia and the Victorian Community Organisations supported our fourth option that all distributors exempt grid-scale batteries from network tariffs if the battery is registered as a scheduled load.[106] EnergyAustralia also wanted further information, and considered that the use of the network and storage assets can continue to be optimised.[107]

We appreciate stakeholder feedback on our draft decision, and acknowledge that tariff treatment of grid-scale storage is an important issue which should continue to be explored. Section 19.4.3 includes discussion of our final decision on the tariff treatment of grid-scale batteries.

Large consumers want distributors to keep exploring tariff structures

Stakeholders were largely supportive of the distributors' large business tariffs but considered that large business tariffs can continue to evolve over time.[108] They acknowledged the reasons provided by the distributors for not offering large businesses choice, such as insufficient time to create an entirely new large business tariff[109] and the costs involved in such a tariff.[110] However, stakeholders supported trials to explore alternative large business tariffs for the 2026–31 regulatory control period.[111] It is also worth noting that while most stakeholders supported tariff choice for large businesses, the EUAA queried whether the benefits justified introducing a further large business tariff.[112]

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105 AER, *Attachment 19: Tariff structure statement | Draft decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy 2021–26*, September 2020, pp. 29 – 32.

106 Firm Power, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; Victorian Community Organisations, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 29. NB VCO also supports option 2.

107 EnergyAustralia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021.

108 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12; AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

109 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 20211, p 78.

110 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, *Spencer&Co Report*, January 2021, p 20.

111 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

112 EUAA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 11. NB, EUAA's submission is targeted at AusNet Services.

We acknowledge the efforts the distributors have made to reflect stakeholder feedback on large business tariff structures. For example, the distributors have made their existing large businesses tariffs more cost reflective and have provided greater clarity in their revised proposals for businesses wanting to change tariff classes. The distributors have also committed to exploring the issue further through trials over this regulatory period as well. Choice for large business customers is discussed further in Section 19.4.1.

The emerging electric vehicle industry is looking for guidance

Stakeholders are interested in understanding how electric vehicle use can be better integrated with tariffs to help reduce the strain electric vehicle charging could place on networks. The electric vehicle industry has not previously been given specific consideration within our tariff structure statement assessments. In this case, the Victorian distributors, the charging station industry, the Victorian Government, and a number of consumer groups considered it important that the ability of tariff strategies to inform behaviour in the emerging electrical vehicle industry be explicitly considered.

Stakeholders submitted that electric vehicle users and charging stations should be provided with appropriate price signals to which they may respond. They expressed support for achieving a balance between facilitating electric vehicle take up and ensuring that tariffs remain technology neutral. They also wanted to be confident that consumers are paying their share of the use of the network.

For instance, DELWP made a submission to the distributors' initial proposals requiring that residential and small business electric owners be moved to the new, more cost-reflective ToU tariffs without access to the flat rate tariff.[113] This is intended to ensure these consumers are being integrated into the system from the beginning and will be encouraged to avoid placing strain on the network. We have edited the distributors' revised tariff structure statements to ensure this requirement is clear for customers and their retailers.

ECA and the CCP17 advocated for electric vehicle uptake to be incentivised to improve utilisation of existing infrastructure and to encourage distributors to trial alternative tariff arrangements in this period.[114] Other stakeholders also agreed that any trials should take into consideration that electric vehicle users and charging stations should ultimately be treated the same as other customers with similar loads.[115]

Some stakeholders had concerns specific to electric vehicle charging stations. Evie and the Electric Vehicle Council wanted to better understand the interaction between connections charges and network tariffs. They raised concerns that connection

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113 Victorian Department of the Environment, Land, Water and Planning, *Victorian Government submission on tariff structure statements 2021–26*, 29 May 2020, p.1.

114 Energy Consumers Australia, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 12; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 84.

115 AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

arrangements and tariff assignment policies are expensive for charging stations and potentially prohibit investment in charging infrastructure.[116]

In response to Evie and the Electric Vehicle Council, we note that the NER requires load with similar characteristics to be treated consistently.[117] This means that charging stations should be assigned to the same tariff class and face the same tariffs as other customers with peaky demand but low utilisation. For example, irrigators and medical imaging facilities.

Assigning charging stations less cost reflective tariffs could give rise to increased risk of networks needing to undertake costly network investment to manage network constraints. Those investment costs would not be financed only by the charging stations but would be borne by all consumers connected to the relevant network.

On the connection charge issue raised by Evie and the Electric Vehicle Council, connection charges are calculated on the basis of expected future revenue to be earned by the distributor from the connecting consumer. Double charging for required augmentation of network assets is avoided by the methodology used to calculate connection charges. We provided guidance on this in our draft decision.[118]

More generally, we agree with stakeholders that electric vehicle charging behaviour is an important issue for electricity networks. To inform our final decision we held an electric vehicle workshop in November 2020, in addition to holding a number of bilateral meetings with stakeholders. This engagement supported our view that tariff trials over the next five years will help distributors understand how to signal the cost of serving these customers, and provide incentives for behavioural change. We encourage distributors to target these trials at both small electric vehicle customer tariff arrangements and at charging stations. More consideration of electric vehicles is provided in Appendix C.

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116 Evie, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 11; Electric Vehicle Council, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 6.

117 NER cl. 6.18.4(a)(2).

118 AER, *Attachment 18: Connection policy – Draft decision – AusNet Services, CitiPower, Jemena, Powercor, and United Energy 2021–26*, September 2020, pp. 5-6.

A Assigning retail customers to tariff classes

This appendix sets out our determination on the Victorian distributors' principles governing the assignment or reassignment of retail customers for direct control services.[119] We approve their procedures for assigning and reassigning retail customers to tariff classes.

Procedures for assigning and reassigning retail customers to tariff classes

The procedure outlined in this section applies to direct control services for the regulatory control period commencing 1 July 2021.

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

Customers of the Victorian distributors will be taken to be assigned to the tariff class which was charging that retail customer immediately prior to 1 July 2021, if:

- they were a customer prior to 1 July 2021, and
- continue to be a customer as at 1 July 2021.

Assignment of new customers to a tariff class during the next regulatory control period

- New connection as identified through the receipt of a connection application will trigger assignment.
- Customers who lodge an application to modify or upgrade an existing network connection from single to three-phase or to bi-directional flow will be treated identically to a new customer. A change of occupancy will also be treated like a new customer for tariff class assignment.
- Customers will be assigned to a tariff class on the basis of the nature of the customer's usage (annual consumption and maximum demand), connection, and metering technology in accordance with the eligibility criteria defined in the distributor's approved tariff structure statement.
- The distributors will ensure that customers with similar connection and usage profiles, regardless of whether they have micro-generation facilities, are treated equally with respect to tariff class assignment.

Reassignment of existing customers to another existing or a new tariff class during the next regulatory control period

- Reassignment can be triggered when an existing customer's load, connection and/or metering characteristics have changed such that it is no longer appropriate

119 NER cl. 6.12.1(17).

for that customer to be assigned to the tariff class to which the customer is currently assigned. A change in use between residential and non-residential (e.g. small business) will also trigger reassignment.

- Reassignment can be triggered by the distributor or a customers' retailer.
- Customers may notify their retailer if they identify that their current tariff class assignment is no longer appropriate.
- Retailers may make an application for tariff class reassignment at anytime, although customers within AusNet Services and Jemena's network will be limited to one application in any 12 month period per connection point. Distributors will consider exceptions on a case-by-case basis.
- Whether the retailer or the distributor initiates the tariff class reassignment, the distributor will use the system of assessment described above to reassign the customer to the appropriate tariff class.
- The tariff class change should be applied as soon as can be reasonably implemented.

Reassignment triggered by the customer's retailer

- Customers and their retailers should monitor the suitability of the tariff class applied.[120] Where a customer or their retailer identifies the existing tariff class is not suitable, they must advise the distributor of the need for reassignment.
- To request a tariff class reassignment on its own initiative or at the customer's request, the retailer must provide information[121] reasonably requested by the distributor.[122]

Reassignment triggered by the distributor

- Where the distributor initiates the tariff class reassignment, it will provide a notice to the customer's retailer prior to the actual tariff class reassignment.

Notification of proposed assignments and reassignments

- Distributors will notify their customer's retailer in writing of an intended reassignment of a customer to another tariff class.
- If a request for further information is received from a customer's retailer, it will be provided within a reasonable timeframe.

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[120] CitiPower, Jemena, Powercor and United Energy will continue to provide an arrangement introduced in the 2017 amendment of the AMI Tariff Order in Council to allow business customers consuming under 160 MWh a year access to a tariff structure with the demand component set to zero regardless of the customer's tariff class.

[121] To request reassignment from the large to small business tariff class, CitiPower, Powercor, and United Energy require confirmation that the load for the connection point has been limited to ensure the site cannot exceed demand greater than 120 kVA. The load can be limited through a supply capacity control device or other types of load limiting devices and a copy of the Certificate of Electrical Safety must be supplied as evidence of the works completed on site.

[122] Please note Jemena requires this to be submitted using their Tariff Reassignment Form in Appendix C of their tariff structure statement.

- If the customer's retailer wishes to object to the tariff class reassignment, they need to demonstrate that the customer does not meet the eligibility criteria of the intended tariff class to which they have been assigned.[123]
- If an objection is received from the customer's retailer, the reassignment will be reconsidered taking into account the relevant facts, and the customer's retailer will be notified in writing of the reconsidered decision and the reasons for that decision.
- If the customer's retailer remains unsatisfied they may contact the Energy and Water Ombudsman (Victoria) or seek a decision from the Australian Energy Regulator using the dispute resolution process available under Part 10 of the National Electricity Law.

123 Please note Jemena requires this to be submitted using their Tariff Reassignment Objection Form in Appendix D of their tariff structure statement and submitted to CustomerRelations@jemena.com.au.

B Integrating network tariff, demand management and DER integration strategies

Our draft decision requested that the Victorian distributors make linkages between their DER, demand management, and tariff strategies clearer. We did so because appropriate integration of tariffs with demand management and other initiatives ensures that consumers will pay no more than necessary for network services. It will also facilitate least cost integration of DER onto distribution networks.

This appendix explores how the distributors responded to our request for greater clarity regarding interactions between their proposed tariff strategies and initiatives to integrate DER technologies, including through demand management initiatives.

Consumers and stakeholders supported our request. Their submissions requested that distributors outline how their strategies are aligned and to provide a narrative as to how this fits into their longer-term pricing strategies.[124] [125]

Efficient integration of DER into networks can also facilitate the emergence of new markets and third party providers who can provide network support services to distributors. This has the potential to benefit customers, networks, and wholesale markets through aligning price signals and complementary measures to coordinate consumption, generation, storage, and use of networks.

Some strategies are consistent across Victorian distributors

The distributors made efforts to better explain the interlinkages in their revised proposal. For residential tariffs, they addressed stakeholder concerns about the adoption of a two part time of use tariff structure instead of a solar sponge amidst rising solar PV generation. They explained that their time of use tariffs would act similarly to SAPN's solar sponge tariff. This included a diagram to demonstrate how their low off-peak rates encouraged more consumption during the day and less during the early evening peak. By encouraging greater consumption during the day, these tariffs complement their efforts to accommodate increasing levels of solar exports on their networks.

Distributors also considered the impact of the current operating environment on network tariff reform. Factors such as tariff simplicity, equity and the rate of peak demand growth have meant that change has been gradual. It has also resulted in more targeted complementary initiatives, such as demand management. However, the

124 Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2; CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 70; AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 2.

125 ECA, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 20211, p. 12; ECA, Spencer&Co report, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p. 17.

distributors recognised that tariff reform complements their DER integration strategies by driving the long-term behavioural changes they need from customers.

The distributors recognised that trials under the sub-threshold tariffs provisions of the NER can provide insights and evidence to inform their preparations for more cost reflective tariffs in the future.[126] It is encouraging that all Victorian distributors committed to either exploring or trialling new tariffs, with a particular focus on DER initiatives such as electric and storage, to complement their broader strategies.

We provide specific comments for each distributor below.

AusNet Services is building its knowledge through ARENA trials at this stage

AusNet Services provided information on how its current pricing approach encouraged its consumers to consider their usage patterns through a variety of price signals while allowing AusNet to consider demand management as a way to defer augmentation expenditure (augex).

For the next regulatory period, AusNet Services committed to developing tariff trials with interested participants. These include locational and individually calculated consumer cost-reflective tariffs that could apply to grid scale storage as well as specific DER and demand management initiatives. For example, AusNet Services committed to trials to complement the emerging electric vehicle industry through their involvement in ARENA's electric vehicle charging trial, as well as considering ECA's voluntary 'prices for devices' tariff.[127] We also note AusNet Services' involvement in ARENA's DER Marketplace trial, which should also yield consumer insights to inform future tariff structure statements.[128]

We are encouraged by AusNet Services' commitments and its openness to exploring new trials through a variety of means, including engagement with stakeholders to investigate new tariff structures. We expect that AusNet Services will use learnings derived from these projects as an evidence base for more cost-reflective tariffs in the third round of tariff structure statement proposals. This should reduce constraints in its network, whether consumption or export driven, and accordingly the expenditure required to manage them.

CitiPower, Powercor and United Energy already have a number of tariff trials underway

CitiPower, Powercor and United Energy provided a coordinated statement on how their tariff strategies align with demand management and other initiatives. Their explanation focused on how their DER integration program (Future Networks) would complement

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126 NER, cl. 6.18.1C.

127 AusNet Services, *Tariff structure statement – Explanatory document 2021–26*, 3 December 2020, pp. 24–25.

128 ARENA, *Distributed energy marketplace trial giving consumers an edge,* 2 December 2020, https://arena.gov.au/news/distributed-energy-marketplace-trial-giving-consumers-an-edge/, accessed on 29 January 2021.

their time of use tariffs to modify customer behaviour. The three distributors expect that they will at least halve augmentation capex investment for the next regulatory period compared to what would otherwise have occurred[129].

The three distributors identified tariff trials in their tariff structure statements that are planned to commence in the first year of the 2021–26 regulatory control period. These are mainly focused on emerging technologies and include working with retailers to develop:

- dynamic domestic electric vehicle tariffs
- a tariff for the Newstead community project
- another for the United Energy/ARENA battery trial.

We are encouraged by the three distributors committing to further new trials and making efforts to reduce their augex in the next period. We expect that the three distributors will reflect these efforts to introduce more cost reflective tariffs and to find further means to reduce expenditure in their 2026–31 tariff structure statement proposals.

Jemena is focusing on its Future Grid program

Jemena estimated that by the end of the next regulatory period around 12 per cent of its customers will be on the time of use tariff. Jemena considers this gradual change won't be material enough to reduce peak demand for the 2026–31 regulatory control period. Jemena will complement tariff reform with its Future Grid program.[130] Under this program Jemena hopes to implement dynamic export constraints to manage increasing solar generation in Jemena's network. These would work alongside its tariffs encouraging day-time consumption.

Jemena promised to continue monitoring the interactions between tariffs and behaviour change to inform future tariff structure statement proposals, and said that it would investigate the possibility of holding trials, such as for electric vehicle owners or charging stations after 2020–21.

While Jemena has made some efforts in making the links between its strategies clearer, we would like to see more coordination between its tariff strategy and expenditure in its 2026–31 tariff structure statement.

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129 CitiPower, *Tariff structure statement – Explanatory document 202126*, 3 December 2020, p. 9; Powercor, *Tariff structure statement – Explanatory document 2021–26*, 3 December 2020, p. 9; United Energy, *Tariff structure statement – Explanatory document 2021–26*, 3 December 2020, p. 9.

130 Jemena, *Att 12-02: Tariff structure statement – Explanatory document for 1 July 2021 to 30 June 2026*, 3 December 2020, p. 29.

C Electric vehicles

This appendix describes the implications of our determination on the Victorian distributors' tariff structure statements for the integration of electric vehicles and associated charging infrastructure.

The electric vehicle industry in Australia is in its early development. This is the first time electric vehicles have been given specific consideration in the context of a tariff structure statement determination.

We received a number of submissions regarding the treatment of electric vehicles and met with stakeholders to inform our draft decision. We then ran an electric vehicle workshop with participation from charging station companies, consumer groups, retailers, the Victorian Government and distributors. At the workshop a number of stakeholders presented on issues facing electric vehicle owners and charging station operators while we described our tariff structure statement draft decision and reasoning.

We support the distributors' continued engagement with electric vehicle stakeholders to explore how to implement more cost-reflective electric vehicle tariff strategies in their third round of tariff structure statement proposals. We note there is support from other stakeholders, such as from Infrastructure Victoria, for cost-reflective pricing to encourage businesses and individuals to shift their energy use to off-peak times and reduce constraints in the network.[131] However, there is also support from stakeholders for more work to be undertaken in this space to inform future tariff structures.[132] We will continue to work with distributors and stakeholders in Victoria and other jurisdictions to account for electric vehicle stakeholder views while progressing network tariff reform.

Residential electric vehicle users are encouraged to engage with cost reflective network tariffs

The Victorian Government requires all electric vehicle owners to be assigned to cost reflective tariffs, such as time of use or demand.[133] To implement this policy the distributors amended their tariff structure statement proposals to confirm that existing residential electric vehicle users, once identified, will be not have access to flat rate tariffs. We have edited the distributors' tariff structure statements to make this position even clearer for stakeholders.

Distributors will encourage existing electric vehicle users to move to the new time of use tariff by providing a discount relative to the flat rate tariff. They have also committed to exploring potential tariff trials for consumers with electric vehicles, with some distributors already in the process of establishing trials.

[131] Infrastructure Victoria, *Victoria's Draft 30-Year Infrastructure Strategy, Volume 1,* December 2020, p 47.

[132] Submissions from CCP17, Evie, Electric Vehicle Council.

[133] Victorian Department of the Environment, Land, Water and Planning, *Victorian Government submission on tariff structure statements 2021–26*, 29 May 2020, p.1.

The distributors have tried to address charging stations' concerns

All five distributors have made efforts to address concerns raised by electric vehicle charging stations. In particular they have made efforts to more clearly communicate the characteristics defining each tariff class and to provide optionality in their proposals. They have also committed to exploring potential structures to trial over the regulatory control period to inform their strategies for their 2026–31 tariff structure statements. Stakeholders support the use of trials during the 2021−26 regulatory period, and acknowledge that the electric vehicle industry is in its early development.[134]

Some stakeholders raised concerns that when demand tariffs are applied to peaky demand with low overall usage, the per unit costs can be quite high.[135] We note that these load characteristics are shared with a number of industries besides electric vehicles charging stations, such as irrigators and medical imaging facilities.

With their revised proposals the distributors made efforts to help customers better understand that the network must be built to accommodate peak demand and this is what drives the majority of their costs. It is inappropriate to look at usage alone when attempting to set cost reflective tariffs. With that said, the distributors made amendments to their proposed tariff structure statements to address concerns raised by charging station stakeholders.

Tariff class assignment policies must comply with the NER

One of the concerns raised by electric vehicle charging station stakeholders was that the large business tariff class does not take into account the relatively low usage of the network by charging stations, despite the high peaks.[136] The electric vehicle charging industry also questioned the suitability of peak demand (kVA) as a characteristic for these tariff classes, claiming that current tariffs hinder investment in electric vehicle charging infrastructure.[137] They requested a charging station-specific tariff based on consumption, rather than peak demand, as a short-term measure while a more cost-reflective tariff is developed and/or electric vehicle usage continues to be low relative to charging station peak demand.[138]

However, the distributors are unlikely to be able to establish a tariff class specifically for electric vehicle charging stations. The NER requires networks to establish tariff

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134 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 84; Origin Energy, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

135 Submissions from Evie and Electric Vehicle Council.

136 Evie, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 1; Electric Vehicle Council, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 6.

137 Evie, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, pp 1-2; Electric Vehicle Council, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 7.

138 Evie, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2; Electric Vehicle Council, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 7.

classes which group consumers according to their load, connection and metering characteristics.[139] This means all customers must be treated like other customers with similar characteristics.[140]

Stakeholders submitted support for consistent treatment of customers with similar loads.[141] At this stage there is insufficient information to suggest that charging stations materially differ in their load characteristics, such as annual consumption and maximum demand, from other medium to large business customers.[142]

Moreover, for customers with peaky load profiles and potential to place significant strain on local network assets, tariffs signalling the costs of that load are appropriate. Without those price signals networks may have to invest in additional network capacity. All consumers will contribute to recovering those costs.

Distributors have amended their proposed tariff structure statements to address some of the electric vehicle charging industry's concerns. CitiPower, Powercor and United Energy are allowing customers on large business tariffs to move to other tariff classes if the load for the connection point is limited to 200 amps per phase, to ensure that the site cannot exceed a demand greater than 120 kVA.[143] AusNet Services also clarified that customers on its critical peak demand tariffs can request to either increase or decrease their capacity, with their network tariff increasing or decreasing accordingly.[144]

Additionally, CitiPower, Jemena, Powercor and United Energy have aligned their kVA criteria to 120 kVA to make this easier for stakeholders.[145] They clarified this criteria is important as 120 kVA is the maximum that can be supplied using overhead lines[146] while different assets are used to supply larger consumers. This criteria allows them to establish tariffs targeted at reflecting the costs of the assets used to supply different types of consumers.

Distributors have tried to provide more flexibility

The distributors have made efforts to provide greater flexibility, despite not introducing additional tariffs for the medium and large business tariff class. As discussed in Section 19.4.1, this partly reflects the challenges of designing and consulting on new tariff structures in short time periods. Stakeholders generally accepted this point.[147]

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139 NER cl. 6.18.4(a)(1).

140 NER cl. 6.18.4 (a)(2).

141 AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

142 AER, *Summary of EV workshop on Victorian tariff structure statement proposals for 2021–26*, 11 November 2020, p 2. <https://www.aer.gov.au/system/files/Summary%20-%20EV%20Workshop%20on%20VIC%20TSS_0.pdf>.

143 CitiPower, Powercor, United Energy; *Revised Regulatory Proposal, Tariff Structure Statement 2021–26*, December 2020, p 14.

144 AusNet Services; *Revised Tariff Structure Statement 2022 – 26, Compliance Document,* December 2020, p 23.

145 AusNet Services does not have this criteria but has also taken a different approach to tariff structures for the medium and large business tariff classes.

146 Jemena, *Revised Regulatory Proposal, Att 12-02, Tariff Structure Statement Explanatory Document,* December 2020, p 11.

147 CCP17, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 78; AGL, *Submission on the Victorian EDPR Revised Proposal and draft decision 2021–26*, January 2021, p 2.

CitiPower, Jemena and Powercor proposed to transition to United Energy's tariff structures with an incentive demand component alongside the anytime demand charging component.[148] This means that while customers (including electric vehicle charging stations) will not have an option of tariff structure, they will have more ability to engage with price signals and reduce their bills by shifting their consumption outside the peak demand periods. Distributors have also provided a transition path for customers seeking to move across to the new structure incrementally.

The distributors have also committed to exploring tariff trials during the regulatory control period to enable more informed strategies for their next tariff structure statement proposals for the 2026−31 regulatory control period. This includes commitments to explore trials directly with charging stations.

Additionally, CitiPower, Jemena, Powercor and United Energy have stated in both their initial and revised proposed tariff structure statements that they will maintain an arrangement introduced by the Victorian Government in 2017. This arrangement allows for medium businesses which consume less than 160 MWh a year access to a tariff structure with the demand parameter set to zero. This arrangement applies regardless of tariff class.

The AMI Tariff Order in Council which introduced this arrangement is due to expire in June 2021. By including it in their proposed tariff structure statements the distributors have ensured it will remain for the 2021–26 regulatory control period.[149]

Distributors' are engaging with tariff trials

The distributors have been engaging with electric vehicle stakeholders both through the reset process and within broader NEM-wide processes such as the Distributed Energy Integration Program (DEIP) electric vehicle taskforces. These forums have been focused at both small customers with electric vehicles and charging stations providing supporting infrastructure.

For residential electric vehicle customers, AusNet Services and Jemena are engaging with ECA's proposed tariff to explore whether they can establish a trial later in the regulatory period.[150] Additionally, CitiPower, Powercor and United Energy are working with retailers to trial more dynamic electric vehicle tariffs in the first year of the

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148 CitiPower, Powercor, United Energy; *Revised Regulatory Proposal, Tariff Structure Statement, APP05, Explanatory Document 2021–26*, December 2020, p 17; Jemena, *Revised Regulatory Proposal, Att 12-02, Tariff Structure Statement Explanatory Document,* December 2020, p 61.

149 Jemena*, Initial Regulatory Proposal, Att 08-01, Tariff Structure Statement,* January 2020, p 14; Jemena, *Revised Regulatory Proposal, Att 12-02, Tariff Structure Statement, JEN tariff assignment and reassignment policy,* December 2020, p 9. ;United Energy, *Initial Regulatory Proposal, Tariff Structure Statement 2021–26*, January 2020, p 19; Powercor, *Initial Regulatory Proposal, Tariff Structure Statement 2021–26, January 2020,* p 20; CitiPower, *Initial Regulatory Proposal, Tariff Structure Statement 2021–26, January 2020,* p 19; CitiPower, Powercor, United Energy; *Revised Regulatory Proposal, Tariff Structure Statement 2021–26*, December 2020, p 6;AusNet Services, *Initial Tariff Structure Statement 2022 – 26, Compliance Document,* January 2020, p 8; AusNet Services, *Revised Tariff Structure Statement 2022 – 26, Compliance Document,* December 2020, p 9.

150 AusNet Services; *Revised Tariff Structure Statement 2022 – 26, Compliance Document*, December 2020, pp 24-25; Jemena, Revised Regulatory Proposal, Att 12-02, Tariff Structure Statement Explanatory Document, December 2020, pp 29, 69.

regulatory period, which could include nominating the half-hour pricing profile for each day, a day in advance.[151] These distributors have also committed to exploring alternative tariffs throughout the reset period.[152]

All five distributors have committed to exploring more innovative arrangements to trial for electrical vehicle charging stations.[153] Outside of tariff trials, Jemena, United Energy and AusNet Services are also involved in the ARENA / AGL electric vehicle trial to help test the impact of electric vehicle charging on the electricity grid.[154] This trial may have implications for future tariff strategies and trials.

While these trials will be progressed with the electric vehicle charging industry, the lessons they generate will inform the tariff strategies for all customers in the 2026–31 regulatory control period.

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151 CitiPower, Powercor, United Energy; *Revised Regulatory Proposal, Tariff Structure Statement, APP05, Explanatory Document 2021 2026*, December 2020, p 11.

152 CitiPower, Powercor, United Energy; *Revised Regulatory Proposal, Tariff Structure Statement, APP05, Explanatory Document 2021 2026*, December 2020, p 11.

153 NB: Jemena stated in its revised proposal explanatory document that it had not been approached by Evie or EVC regarding tariff trials before the draft decision was published. Jemena, *Revised Regulatory Proposal, Att 12-02, Tariff Structure Statement Explanatory Document,* December 2020, pp 69.

154 AGL, Media Release: AGL and ARENA launch 8 million trial to test impacts of electric vehicles, November 2020. https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2020/november/agl-and-arena-launch-8-million-trial-to-test-impacts-of-electric-vehicles

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
ARENA	Australian Renewable Energy Agency
augex	augmentation expenditure
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
DELWP	Victorian Department of Environment, Land, Water and Planning
DER	Distributed energy resource
distributor	distribution network service provider
DPPC	designated pricing proposal charges
DUoS	distribution use of system
ECA	Energy Consumers Australia
EV	electrical vehicle
GESS	Ganawarra Energy Storage System
ICC	Individually calculated customer
LRMC	long run marginal cost
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
repex	replacement expenditure
RIN	regulatory information notice
ToU	time of use
TUoS	transmission use of system

Shortened form	Extended form
VDO	Victorian Default Offer