DRAFT DECISION

United Energy
Distribution Determination
2021 to 2026

Attachment 6
Operating expenditure

September 2020

AUSTRALIAN ENERGY REGULATOR

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Note

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

The draft 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 11 – Demand management incentive scheme and demand management innovation allowance mechanism

Attachment 12 – Not applicable to this distributor

Attachment 13 – Classification of services

Attachment 14 – Control mechanisms

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

Attachment 19 – Tariff structure statement

Attachment A – Victorian f-factor incentive scheme

Contents

6 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services. Forecast opex is one of the building blocks we use to determine United Energy's total regulated revenue requirement.

This attachment outlines our assessment of United Energy's proposed opex forecast for the 2021–26 regulatory control period.

6.1 Draft decision

United Energy initially proposed a total opex forecast of $797.7 million ($2020–21) [1] for the 2021–26 period. On 15 May, United Energy submitted an updated proposal[2] where it proposed an updated total opex forecast of $785.9 million ($2020–21) to account for withdrawing its Environment Protection Act Amendment step change due to the deferral in the associated legislation. Opex represents 37.8 per cent of United Energy's total revenue proposal.[3]

We do not accept United Energy's distribution opex forecast of $785.9 million ($2020–21) for the 2021–26 regulatory control period because we are not satisfied that it reasonably reflects the opex criteria.[4]

Our draft decision is to include our alternative total opex forecast of $694.6 million ($2020–21) in United Energy's allowed revenue for the 2021–26 period. This is $91.4 million, or 11.6 per cent, lower than United Energy’s total opex forecast of $785.9 million ($2020–21).[5]

Our draft decision opex forecast is also $95.0 million (or 12.0 per cent) lower than the opex forecast we approved in our final decision for the 2016–20 regulatory control period and $51.2 million (or 8.0 per cent) higher than United Energy's actual (and estimated) opex in the 2016–20 regulatory control period.

Figure 6.1 shows United Energy's actual opex, our previous approved forecast, proposed opex for the next 5 years and our draft decision.

1 Including debt raising costs; United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 140.

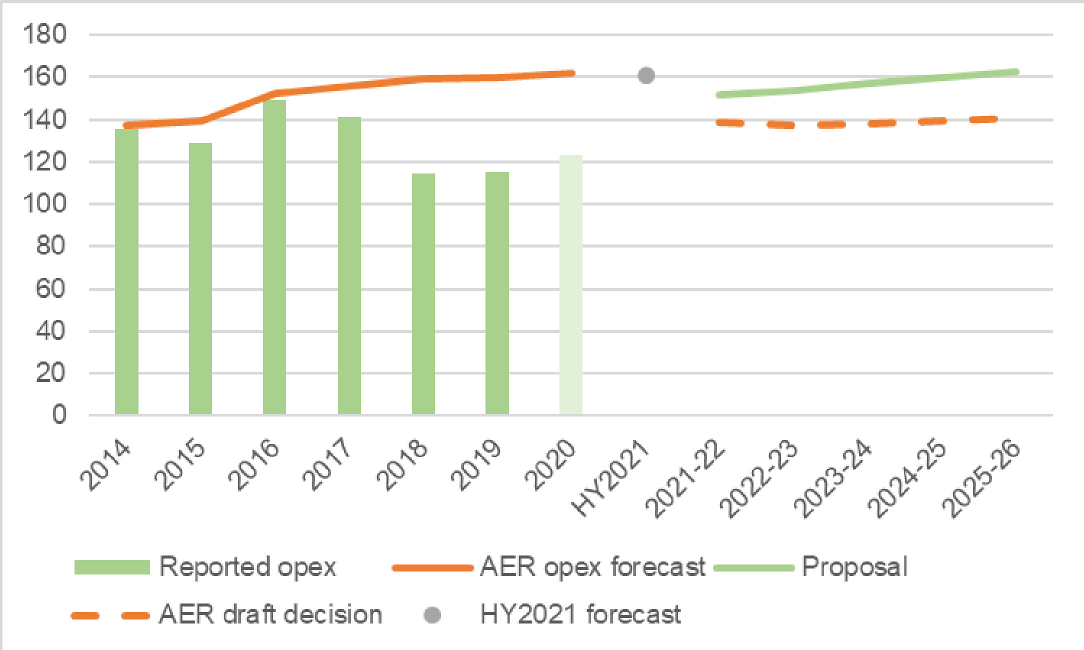
2 Powercor, CitiPower, and United Energy, *Amendments to operating expenditure step changes and capital programs*, 15 May 2020.

3 United Energy, *2021–26 Regulatory proposal – Supporting document 10.02 – PTRM 2021–26 (updated)*, May 2020.

4 NER, cll. 6.5.6(c)-(d).

5 Including debt raising costs.

Figure 6.1 United Energy's opex over time ($ million, 2020–21)



Source: United Energy, *2021–26 Regulatory proposal – Supporting document RIN001 – Workbook 1 – Reg determination*, January 2020; United Energy, *2021–26 Regulatory proposal – Supporting document 10.02 – Opex model (updated)*, May 2020; AER, *Draft Decision, United Energy distribution determination 2021–26, Opex model,* September 2020; AER, *Draft Decision, United Energy distribution determination 2021–26, EBSS model,* September 2020; AER analysis.

Table 6.1 below sets out United Energy's proposal, including updates it submitted, our alternative estimate for the draft decision and key differences.

Table 6.1 Comparison of United Energy's proposal and our draft decision on opex ($ million, 2020–21)

	United Energy proposal	Updated proposal	AER draft decision	Difference
Base (reported opex in 2019)	616.6	616.6	598.8	–17.8
Base year adjustments	32.0	32.0	19.9	–12.1
Final year increment	16.8	16.8	17.9	1.1
Trend: Output growth	25.3	25.3	15.3	–10.0
Trend: Real price growth	23.6	23.6	1.3	–22.3
Trend: Productivity growth	–9.9	–9.9	–8.7	1.2
Step changes	85.6	73.8	40.6	–33.2
Category specific forecasts	1.1	1.1	3.6	2.5
Total opex (excluding debt raising costs)	791.3	779.4	688.7	–90.8
Debt raising costs	6.5	6.5	5.9	–0.6

	United Energy proposal	Updated proposal	AER draft decision	Difference
Total opex (including debt raising costs)	797.7	785.9	694.6	–91.4
Percentage difference to proposal				–11.6%

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model,* January 2020; United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model (updated)*, May 2020; AER analysis.

Note: Numbers may not add up to totals due to rounding. The difference is between United Energy's updated proposal and our draft decision.

The following factors have contributed to our lower alternative total opex forecast:

- We used 2019 for base year opex in developing our alternative estimate as our assessment of revealed cost data and benchmarking techniques found that United Energy has been relatively efficient over time. United Energy was ranked fourth in terms of opex efficiency when measured using our econometric models.[6] We have updated for actual 2019 reported opex which was not available at the time the proposal was submitted, which lowers our alternative estimate compared to United Energy's proposal by $17.8 million ($2020–21).
- For base adjustments, our alternative estimate is $12.1 million ($2020–21) lower than United Energy's proposal. The main driver of this difference is we have reduced the amount proposed for the reclassification of replacement expenditure on faults and minor repairs as opex.
- With the exception of forecasting labour price growth, we have used our standard approach to trend opex forward over the next five years. For labour price growth, we have used a forecast prepared by Deloitte Access Economics rather than the standard approach of averaging two forecasts as this is the only forecast available which factors in the impacts of COVID–19. For the final decision we will consider updating the rate of change forecast using our standard approach provided the necessary forecasts are available.
- We forecast the rate of change for United Energy over the next five years is on average 0.5 per cent each year. This is lower than United Energy's proposed 1.9 per cent per year. This is primarily driven by lower output and price growth forecasts, which in large part reflect the impacts of COVID–19 on forecast customer numbers and wage price growth. This lowers our alternative estimate compared to United Energy's proposal by $31.2 million ($2020–21).
- We generally only include step changes where we are satisfied there are efficient costs associated with new regulatory obligations or capital expenditure (capex)/opex tradeoffs and these costs are not already captured in base opex or

6 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, pp. 29–30.

through our trend forecast. We have included three of the nine step changes (five minute settlement, IT cloud solutions and security of critical infrastructure) proposed by United Energy but have reduced some of the proposed amounts based on our efficiency assessment. We did not include six of the step changes as they were either withdrawn (Environment Protection Act Amendment) or had costs which were immaterial or captured by trend (solar enablement, financial year regulatory information notice (RIN), Energy Safe Victoria (ESV) levy, demand management programs and insurance premiums). This lowers our alternative estimate compared to United Energy's proposal by $33.2 million ($2020–21).

6.2 United Energy's proposal

United Energy used a 'base-step-trend' approach to forecast opex for the 2021–26 regulatory control period, consistent with our preferred approach.

In applying our base-step-trend approach to forecast opex for the 2021–26 regulatory control period, United Energy:[7]

- used opex in 2019 as the base to forecast ($616.6 million ($2020–21))
- adjusted the base year expenditure to include forecast for activities which are not fully reflected in the base year expenditure, including:
  - adjustments for service classified as standard control ($32.0 million $2020–21))
  - adjustment for Guaranteed Service Level (GSL) payments ($1.1 million ($2020–21))
- added the final year increment from the base year of 2019 ($16.8 million ($2020–21))
- applied a rate of change comprising of :
  - real price escalation ($23.6 million ($2020–21))
  - output growth ($25.3 million ($2020–21))
  - and productivity (–$9.9 million ($2020–21))
- added forecast step changes for the 2021–2026 regulatory control period ($73.8 million ($2020–21))
- added forecast debt raising costs ($6.5 million ($2020–21)).

United Energy's total opex forecast is $785.9 million ($2020–21) for the 2021–26 regulatory control period (see Table 6.2). United Energy is forecasting 22.2 per cent higher opex in the 2021–26 regulatory control period compared to its estimated opex in

[7] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 151; United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model(updated)*, May 2020.

the 2016–20 regulatory control period[8]. Opex represents 37.8 per cent of United Energy's total revenue proposal.[9]

Table 6.2 United Energy's proposed opex ($ million, 2020–21)

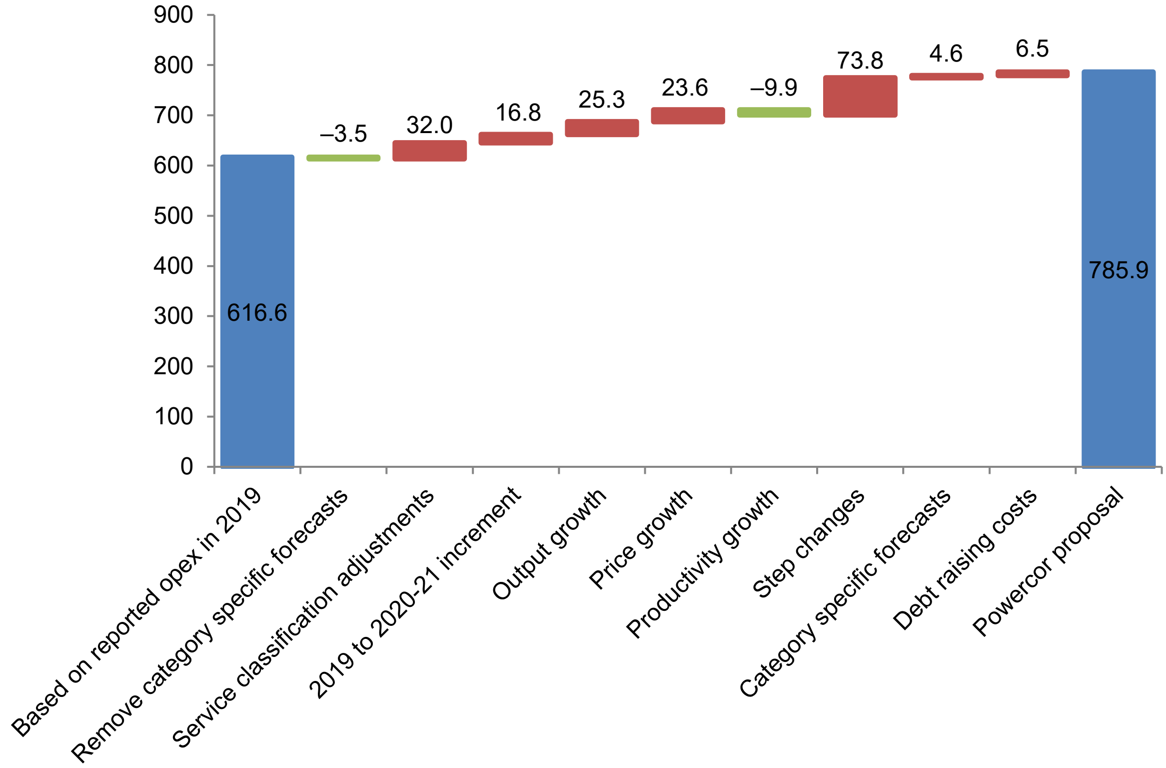
	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Total opex excluding category specific forecasts	150.8	152.3	156.0	158.9	161.5	779.4
Debt raising costs	1.2	1.3	1.3	1.3	1.4	6.5
Total opex	152.0	153.5	157.3	160.3	162.8	785.9

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model (updated)*, May 2020.

Note: Numbers may not add up to totals due to rounding

Figure 6.2 shows the different components in United Energy's opex proposal ($ million, 2020–21).

Figure 6.2 United Energy's opex forecast ($ million, 2020–21)



[8] Comparison is against the 2016–20 period not including HY2021

[9] United Energy, *2021–26 Regulatory proposal – Supporting document 10.02 – PTRM 2021–26 (updated)*, May 2020.

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model (updated)*, May 2020; AER analysis.

6.2.1 Stakeholder views

We received 18 submissions on United Energy's 2021–26 regulatory proposal and a number of them raised issues about opex. At a high level, submissions raised the need to account for the impacts of COVID–19 on economic conditions and forecasts, and raised concerns about the number of step changes proposed. We have taken these submissions, and any other concerns consumers identified in our engagement into account in developing the positions set out in this draft decision. A summary of the opex issues raised in submissions is provided in Table 6.3.

Table 6.3 Submissions on United Energy's opex proposal

Stakeholder	Issue	Description
The AER's Consumer Challenge Panel, sub-panel 17 (CCP17), Origin Energy	Base opex	The CCP17 noted that AusNet and Jemena base opex are in the low range of opex efficiency but are improving in recent years. CitiPower, Powercor and United Energy are strong performers in the Opex multilateral partial factor productivity (MPFP) benchmarking though United Energy's opex productivity is declining.[10] Submissions noted Jemena and AusNet Services choosing 2018 as the base year compared to CitiPower, Powercor and United Energy choosing 2019, reflecting the most recent year with audited data available.[11]
CCP17, Energy Consumers Australia (ECA), Origin Energy, EnergyAustralia (EA), VCO	Step Changes	Multiple submissions expressed concerns with the quantum of step changes and considered the AER needs to test these proposals carefully against the step change criteria with concerns that not all of the proposed step changes meet the step change criteria.[12] ECA noted the step change mechanism does not operate symmetrically and it is rare for a business to put forward negative step changes. It considered this is a further reason why the AER should carefully assess the veracity of each step change.[13] EA questioned whether allowing numerous opex step changes reflects poorly on the integrity of the AER's revealed cost framework and whether it should take a harder line to preserve this.[14]
CCP17, ECA, EA, Origin Energy	Trend	EA submitted that further trend analysis should be undertaken to reveal persistent over- or under-estimation and to ensure credibility of forecasting methods.[15]

10 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, pp. 43–44.

11 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 43; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* 3 June 2020, p. 4.

12 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p. 12; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, June 2020, p. 9.

13 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, June 2020, pp. 27–28.

14 EnergyAustralia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals,* 3 June 2020, p. 8.

Stakeholder	Issue	Description
		The CCP17 considered that output growth forecasts will need to be revisited in light of the impacts of COVID–19 on the economy, including relevant AEMO forecasts that are likely to be revised.[16] Similarly, Origin Energy noted that while it considers it appropriate for the AER to assess the proposed forecasting methodologies, given current economic conditions, it considers that forecast input costs and output growth may need to be substantially revised for the 2021–26 period.[17] ECA submitted evidence is required that the increase in the super guarantee will lead to an increase in total wages rather than a redistribution of salaries between super and taxable salary. Further, to the extent that employees rather than employers bear the burden of the change to super, the adjustments to escalators are likely to be too high.[18] In terms of productivity growth, the CCP17 submitted that a productivity improvement of at least 0.5 per cent per year should be factored into all operating cost projections (recognising that AusNet Services expect to deliver double the annual productivity improvement). Origin Energy also recognised the higher productivity proposed by AusNet Services.[19]
CCP17, Origin Energy, VCO, ECA	5 minute Settlement	ECA considered this qualifies as an acceptable step change but questioned the initial costs proposed due to the delay in implementation.[20] The Victorian Community Organisations questioned the difference in proposed costs the five Victorian businesses, with Jemena not considering there are any related costs and CitiPower considering the costs are relatively small compared to the costs sought by the other businesses.[21]
CCP17	ESV Levy	The CCP17 noted that some businesses have proposed this is a step change whereas AusNet Services proposed to remove it from their base and recover it annually via tariffs and Jemena is proposing it as a category specific forecast. It considers these are exogenous and ongoing operating cost and sees merit in uniformity of approach in dealing with it across the five businesses.[22]
CCP17, VCO	Financial Year RIN	The CCP17 does not consider this step change to be ongoing or material enough to warrant it being regarded as a step change.[23] The Victorian Community Organisations notes that AusNet considers there are no costs associated with these obligations (or has accepted not to claim the

15 Energy Australia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals*, 3 June 2020, p. 7.

16 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 3.

17 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals,* 3 June 2020, p. 4.

18 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, June 2020, p. 30.

19 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p 58; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals,* 3 June 2020, p. 5.

20 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, p. 28.

21 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p 66.

22 CCP17, Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26, 10 June 2020, p. 53.

23 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 54.

Stakeholder	Issue	Description
		cost as part of its agreement with the Customer Forum), which raises the question as to the cost the other businesses are seeking.[24]
CCP17, AGL, Origin Energy	Insurance Premiums	The CCP17 accepted that insurance premiums will rise significantly, but considered the issue is primarily about materiality given that insurance is an ongoing cost for businesses. It noted that these increases for Jemena are perhaps more recent than for CitiPower, Powercor and United Energy who possibly had a significant increase in premiums as result of the last round bushfires and the subsequent Royal Commission.[25] Origin Energy requested that the AER ensures distributor's risk assessments have been appropriately and consistently applied, particularly with respect to insurance premiums.[26]
CCP17, EA	Solar/Future Grid	The CCP17 noted that the AER has observed that there is not a regulatory obligation and questioned the driver. It also observed the recent SA Power Networks proposal, where $3-$4 million was sought for low-voltage network management, and considered the AER's final SA Power Networks decision will be relevant here.[27] EA state that CitiPower, Powercor and United Energy's plan is based on an 'all customers pay' approach on the presumption that all customers benefit. While there are different views on this topic, E A noted that the AER should validate how the distributors arrived at this decision in light of efficiency in pricing as well as direct customer input. Specifically, 65 per cent of customers and stakeholders, including those representing financially vulnerable customers, preferred some form of direct cost recovery from solar customers. Alternative methods of cost recovery seem likely to materially alter the DNSPs' approach, including enabling 5 kVA exports for the large majority of customers. Jemena adopts the ESC's single rate minimum FiT in valuing curtailed solar exports, which will likely overstate their "true" value, particularly over long time horizons with higher rates of PV penetration behind the meter as well as at grid scale. Jemena's use of a 7¢/kWh FiT as a lower bound sensitivity excludes the social cost of carbon, which has merit, but in EA's view it is likely to still overstate the energy only value of PV exports as at today.[28]
CCP17, ECA	IT Cloud	The CCP17 contend that this is considered as part of a capex/opex trade-off and is acceptable as a step change where there is net benefit to customers.[29] ECA state that businesses should only make a decision to move IT systems to the cloud where the benefits of doing so are outweighed by the costs. ECA seeks evidence that all businesses have explicitly considered how cloud migration costs can be offset.[30]
CCP17	GSL	CCP17 is not convinced that the increase to the base year to adjust for some GSL self-funding correlates with the GSL category specific adjustment that

24 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p. 67.

25 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 54.

26 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals,* p. 4.

27 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 55.

28 Energy Australia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals,* 3 June 2020, pp. 13–14.

29 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 55.

30 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, June 2020, p. 29.

Stakeholder	Issue	Description
		some distributors have proposed. The CCP17 are satisfied that the other businesses proposed adjustments are reasonable, recognising that there may be subsequent changes from the Victorian Government.[31]
CCP17	Minor Repairs reclassification	Given that the work does not impact the value of the asset in any appreciable way, the CCP17 agree with the proposal to reclassify a portion of cable and conductor minor repairs from capex to opex. The CCP17 encourage the AER to examine the value of these adjustments.[32] The CCP17 considers that CitiPower, Powercor and United Energy choosing to reclassify some minor line repex as repairs warrants further investigation about best approach by the AER.
CCP17, Origin Energy, EA	COVID–19	Origin Energy consider the COVID–19 pandemic is expected to have an unknown, but significant impact on electricity demand and expenditure within the current and potentially next regulatory control period. To the extent that these impacts extend into the next regulatory control period, it anticipates the businesses' demand and expenditure forecasts will need to be substantially revised.[33] EA also considered the downturn associated with COVID–19 should provide new pressures to achieve cost reductions, as are being felt in competitive sectors of the economy.[34]

6.3 Assessment approach

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[35] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including electricity distribution networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where an opex forecast is granted over a multi-year regulatory control period) and the efficiency benefit sharing scheme (EBSS).

The approach we apply to assessing a business's opex (and which we have applied in this draft decision) is more fully described in the Expenditure Forecast Assessment Guideline,[36] and its accompanying explanatory materials.

31 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 2 June 2020, p. 48.

32 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 49.

33 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals,* 3 June 2020, p. 1.

34 Energy Australia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals,* 3 June 2020, p. 6.

35 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

36 AER, *Expenditure Forecast Assessment Guideline, Explanatory statement* November 2013.

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[37]

Incentive regulation encourages regulated businesses to reduce costs below the regulator's forecast, in order to make higher profits, and 'reveal' their costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory control periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business's commercial interests with consumer interests.

Our general approach is to assess the efficiency of the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using forecasting method as set out in the Expenditure Forecast Assessment Guideline, known as the 'base–step–trend' approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use bottom-up analysis, particularly in relation to our base opex assessment and for step changes.[38]

Benchmarking a network business against others in the National Electricity Market (NEM) provides an indication of whether revealed opex can be adopted as 'base opex' and, if not, what our alternative estimate of base opex should be. While benchmarking is a key tool, we use a combination of techniques to assess whether base opex reasonably reflects the opex criteria.[39] We may make a downward adjustment to the business's revealed opex if we consider it is operating in a materially inefficient manner. Material inefficiency is a concept we introduced in our Expenditure Forecast Assessment Guideline.[40] We consider a service provider is materially inefficient when it is not at, or close to, its peers on the efficiency frontier. We define this more precisely in the context of economic benchmarking below.

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[41] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the National Electricity Rules (NER),[42] and more broadly, the National Electricity Objective (NEO).[43] This is consistent with the requirement that we consider whether *the total* opex forecast, and *not* the individual forecast opex components, reasonably reflects the opex criteria.[44]

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37 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 189.

38 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom-up'.

39 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 12–14.

40 AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

41 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

42 NER, cl. 6.5.6(a).

43 NEL, s. 7.

44 NER, cl. 6.5.6(c).

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [45]

> The key feature of economic regulation of [distribution network service providers] in the NEM is that it is based on incentives rather than prescription…
>
> Importantly, under [incentive-based regulation], funding is not approved for [distribution network service providers'] specific projects or programs. Rather, a total revenue requirement is set, which is based on forecasts of total efficient expenditure. Once a total revenue is set, it is for the [business] to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations…

6.3.2 Base–step–trend forecasting approach

As a comparison tool to assess a business’s opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast regulatory control period, using the base–step–trend forecasting approach. We have regard to the opex factors set out in the NER in making this assessment.[46]

If the business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business's forecast opex.

Figure 6.3 summarises the base–step–trend forecasting approach.

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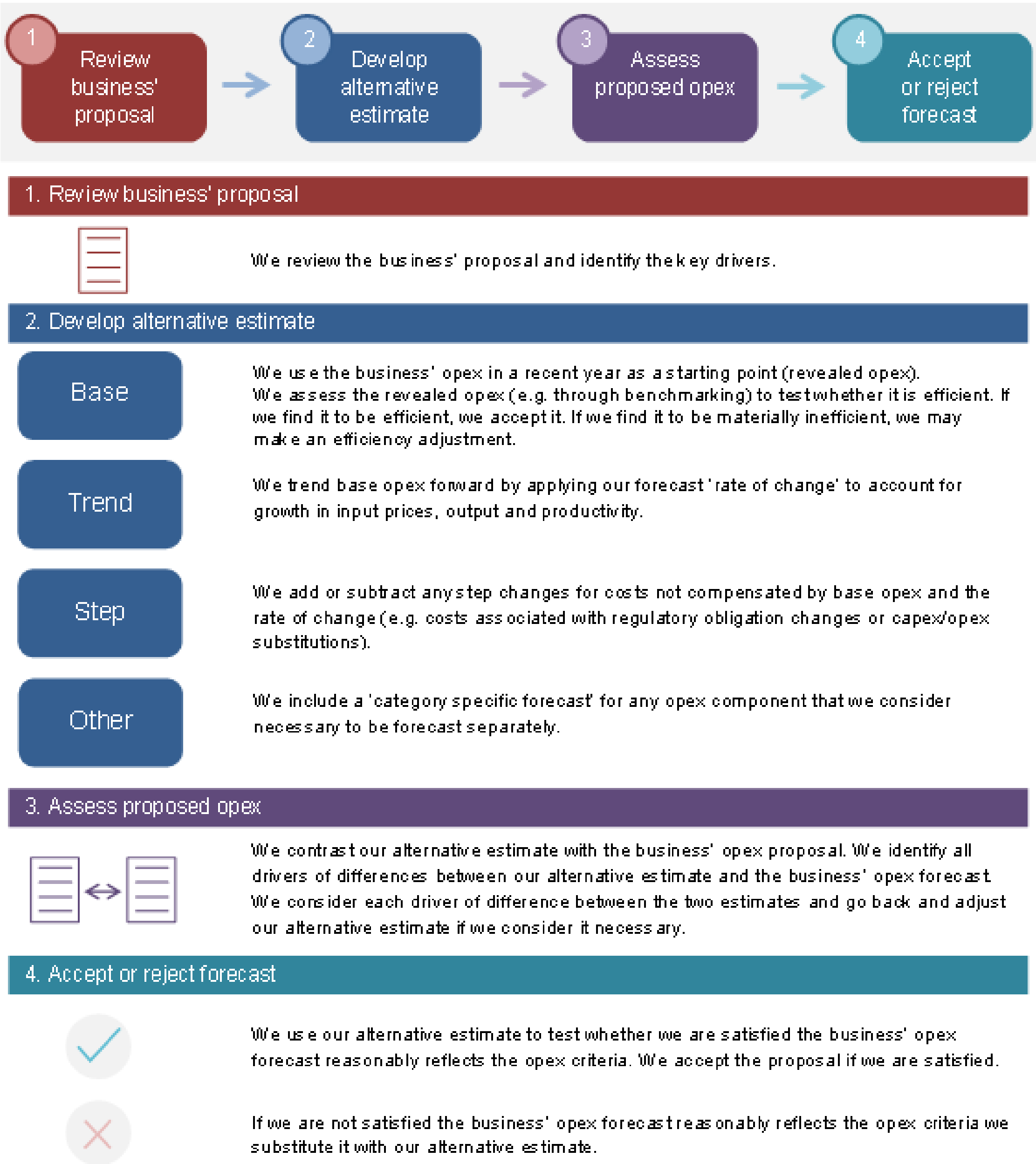
45 AEMC, *Contestability of energy services, Consultation paper*, 15 December 2016, p. 32.

46 NER, cl. 6.5.6(e).

Figure 6.3 Our opex assessment approach



Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business's historical or 'revealed' costs in a recent year as a starting point for our opex forecast.[47] We must have regard to the opex factors in deciding whether we are satisfied that the business's proposed opex forecast reasonably reflects the opex criteria.[48]

47 NER, cl. 6.5.6(e)(5).
48 NER, cl. 6.5.6(e)(5).

We do not simply assume the business's revealed opex is efficient. It may include an ongoing level of inefficient expenditure. We use our benchmarking results[49] and other assessment techniques to test whether the business is operating efficiently.

We consider revealed opex in the base year is generally a good indicator of opex requirements over the next regulatory control period because the level of *total opex* is relatively stable from year to year. This reflects the broadly predictable and recurrent nature of opex.

A business may experience fluctuations in particular categories of opex, and the composition of total opex can change, from year to year. While many operation and maintenance activities are recurrent and non-volatile, some opex projects follow periodic cycles that may or may not occur in any given year, and some opex projects are non-recurrent.

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.

Rate of change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity. We consider that the rate of change takes into account almost all relevant sources of opex growth.

We forecast input price growth using a combination of labour and non-labour price change forecasts. Labour costs represent a significant proportion of a distribution business’s costs.[50] To determine the input price weights for labour and non-labour prices, we have regard to the input price weights of a prudent and efficient benchmark business. Consistent with incentive regulation, this provides the business an incentive to adopt the most efficient mix of inputs throughout the regulatory control period.

We forecast output growth to account for the annual increase in output of services provided. The output measures used should, ideally, be the same measures used to forecast productivity growth.[51] Productivity measures the change in output for a given amount of input.

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49 NER, cl. 6.5.6(e)(4); AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2018.

50 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 49.

51 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 23–24.

The output measures we typically use for distribution businesses are energy delivered, ratcheted maximum demand, customer numbers and circuit length.[52] We do not typically adjust forecast output growth for economies of scale because we account for these in our forecast of productivity growth.

Our forecast of opex productivity growth captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. We generally base our estimate of productivity growth on recent productivity trends across the electricity industry. However, if we consider historic productivity growth does not represent 'business-as-usual' conditions we do not use it to forecast future productivity growth and may rely on other industry or economy wide indicators.

We recently reviewed our approach to forecasting opex productivity growth and determined that a forecast of 0.5 per cent per year reflects a reasonable forecast of the productivity growth a prudent and efficient electricity distributor can make. [53] We stated that we intended to adopt this opex productivity growth forecast when we review the opex forecasts proposed by electricity distributors going forward.[54]

Step changes and category specific forecasts

Lastly, we add or subtract any components of opex that are not appropriately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[55] These adjustments are in the form of 'step changes' or 'category specific forecasts'.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. As explained in the Expenditure Forecast Assessment Guideline, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change and it should not become a step change.[56] In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[57] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.[58]

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[52] These measures are discussed more fully in our benchmarking reports, see AER, *Annual Benchmarking Report, Electricity distribution network service* providers, November 2018, pp. 46–52.

[53] AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

[54] AER, *Final decision paper – Forecasting productivity growth for electricity distributors*, March 2019, p. 11.

[55] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

[56] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

[57] AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

[58] AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

To increase its maximum allowable revenue, a regulated business has an incentive to identify new costs not reflected in base opex or costs increasing at a greater rate than the rate of change. It has no corresponding incentive to identify those costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. Therefore, simply demonstrating that a new cost will be incurred—that is, a cost that was not incurred in the base year—is not a sufficient justification for introducing a step change. There is a risk that including such costs would upwardly bias the total opex forecast.

The test we apply is whether the step change is needed for the opex forecast to achieve the opex objectives in the NER.[59] Our starting position is that only circumstances that would change a business's fundamental opex requirements warrant the inclusion of a step change in the opex forecast.[60] Two typical examples are:

- a material change in the business's regulatory obligations
- a prudent and efficient capex/opex substitution opportunity.[61]

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to comply prudently and efficiently with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[62] This does not include instances where a business has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs the business must incur to comply with its regulatory obligations. Usually when a new regulatory obligation is imposed on a business, it will incur additional expenditure to comply. The business may be expected to continue incurring such costs associated with the new regulatory obligation into future regulatory control periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient to meet the change in regulatory obligations.[63] We stated in the explanatory statement accompanying the Expenditure Forecast Assessment Guideline:[64]

> [Network services providers] will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the [Network services providers] to justify the step change by reference to known cost drivers (for example, volumes of different types of works) if cost drivers are

59 NER, cl. 6.5.6(a).

60 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

61 NER, cl. 6.5.6(e)(7).

62 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

63 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–52; AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

64 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

> identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for [Network services providers] to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would improperly benefit from a higher opex forecast and the efficiency gains.[65]

We may also accept a step change in circumstances where it is prudent and efficient for a network business to increase opex in order to reduce capital costs. We would typically expect such capex/opex trade-off step changes to be associated with replacement expenditure (or "repex").[66] The business should provide robust cost–benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.[67]

In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances. We would consider whether the costs associated with the step change are unavoidable and material—such that base opex, trended forward by the forecast rate of change, would be insufficient for the business to recover its efficient and prudent costs. We would also consider whether the business would continue to incur the costs of a proposed step change in future regulatory control periods.

Category specific forecasts

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time.

A category specific forecast is an amount we may allow to be included in the opex forecast for a particular year, which is not appropriate as a step change, nor for inclusion in base opex, but which we nevertheless consider meets the legal criteria for efficient expenditure in that year.

We may also use category specific forecasts to avoid inconsistency or double counting within our determination. We have typically included category specific forecasts for debt raising costs and the demand management incentive allowance mechanism (DMIAM). In jurisdictions where GSL payments were historically included under

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65 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

66 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 74.

67 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

category specific forecasts, we continue to do so. There are specific reasons for forecasting these categories separately from base opex. For example, we forecast debt raising costs separately to provide consistency with the forecast of the cost of debt in the rate of return building block of allowable revenue. For DMIAM, we forecast these costs separately because we fund them through a separate building block.

Absent such exceptions, we expect that base opex, trended forward by the rate of change, will allow the business to recover its prudent and efficient costs. This is a reasonable assumption given that the business has operated in the past with that level of opex, demonstrating that it is able to operate prudently and efficiently in meeting all its existing regulatory obligations, including its safety and reliability standards. We consider it is also reasonable to expect the same outcome looking forward with the increase provided through the trend growth in the base opex. Some costs may go up, and some costs may go down—despite potential volatility in the cost of certain individual opex activities, total opex is generally relatively stable over time. As we stated above in relation to step changes, a business has an incentive to inflate its total opex forecast by identifying new and increasing costs, but it does not have the same incentive to identify declining costs in its forecasts. Consequently, there is a risk that providing a category specific forecast for opex items identified by the business may upwardly bias the total opex forecast. By applying our revealed cost approach consistently and carefully scrutinising any further adjustments, we avoid this potential bias.

6.3.3 Interrelationships

In assessing United Energy's total forecast opex we also took into account other components of its proposal that could inter-relate with our opex decision.[68] The matters we considered in this regard included:

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and the opex rate of change
- United Energy's proposed step changes which have an upfront opex and capex investment, and subsequent efficiencies in opex and capex
- 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.

68 When making revenue decisions under the NEL, we must specify the manner in which the constituent components of our decision relate to each other, and the manner in which we take account of these interrelationships: NEL, s. 16(1)(c).

6.4 Reasons for draft decision

We do not accept United Energy's distribution opex forecast of $785.9 million[69] ($2020–21) for the 2021–26 regulatory control period because we are not satisfied that it reasonably reflects the opex criteria.[70]

Our draft decision is to include our alternative total opex forecast of $694.6 million ($2020–21) in United Energy's allowed revenue for the 2021–26 period.[71] This is $91.4 million, or 11.6 per cent, lower than United Energy's total opex forecast of $785.9 million ($2020–21).[72] We are satisfied our alternative estimate of total forecast opex for United Energy reasonably reflects the opex criteria.[73]

Table 6.4 below sets out United Energy's proposal, including updates it submitted, our alternative estimate for the draft decision and key differences.

Table 6.4 Comparison of United Energy's proposal and our draft decision on opex ($ million, 2020–21)

	United Energy proposal	Updated proposal	AER draft decision	Difference
Base (reported opex in 2019)	616.6	616.6	598.8	–17.8
Base year adjustments	32.0	32.0	19.9	–12.1
Final year increment	16.8	16.8	17.9	1.1
Trend: Output growth	25.3	25.3	15.3	–10.0
Trend: Real price growth	23.6	23.6	1.3	–22.3
Trend: Productivity growth	–9.9	–9.9	–8.7	1.2
Step changes	85.6	73.8	40.6	–33.2
Category specific forecasts	1.1	1.1	3.6	2.5
Total opex (excluding debt raising costs)	791.3	779.4	688.7	–90.8
Debt raising costs	6.5	6.5	5.9	–0.6
Total opex (including debt raising costs)	797.7	785.9	694.6	–91.4
Percentage difference to proposal				–11.6%

69 Including debt raising costs; United Energy, *2021–26 Regulatory proposal – Supporting document 10.02 – PTRM 2021–26 (updated)*, May 2020.

70 NER, cll. 6.5.6(c)-(d).

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

72 Including debt raising costs.

73 NER, cl. 6.5.6(c).

Source: United Energy, 2021–26 Regulatory proposal – Supporting document 10.06 – Opex model, January 2020; United Energy, 2021–26 Regulatory proposal – Supporting document 10.06 – Opex model (updated), January 2020; AER analysis.

Note: Numbers may not add up to totals due to rounding. The difference is between United Energy's updated proposal and our draft decision.

The main drivers for the differences are set out in section 6.1 and 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

United Energy proposed $123.3 million ($2020–21) total reported opex and selected 2019 for its base year.[74] Following United Energy's regulatory proposal submission in January 2020, we received the 2019 Annual RIN which included actuals for reported opex in 2019.[75] We have based our base efficiency assessment on the updated actuals of $119.8 million ($2020–21). This is consistent with United Energy's proposal which noted that the revised proposal will be updated for audited actual 2019 opex.[76].

United Energy explained that it has chosen 2019 as the base year, as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision[77]. We consider 2019 is an appropriate base year, as it is representative of the base opex required for the next regulatory control period. We also note that, due to the interaction with the EBSS, we are generally indifferent to the choice of base year of a distributor, provided we find its opex efficient.

We consider 2019 is a relatively efficient forecast as indicated by our benchmarking results, and we have used the 2019 revealed cost to develop our alternative estimate. With an ex ante opex forecast over the current regulatory control period and the EBSS, United Energy had the incentive to reduce costs, and our benchmarking results indicate that United Energy is operating relatively efficiently.

As shown in Figure 6.4, United Energy underspent against our approved forecast in the first four years of the 2016–20 regulatory control period and expected to continue this performance in 2020. Our benchmarking results suggest there is sufficient evidence that United Energy's revealed opex over the periods 2006–18 and 2012–18 was relatively efficient.

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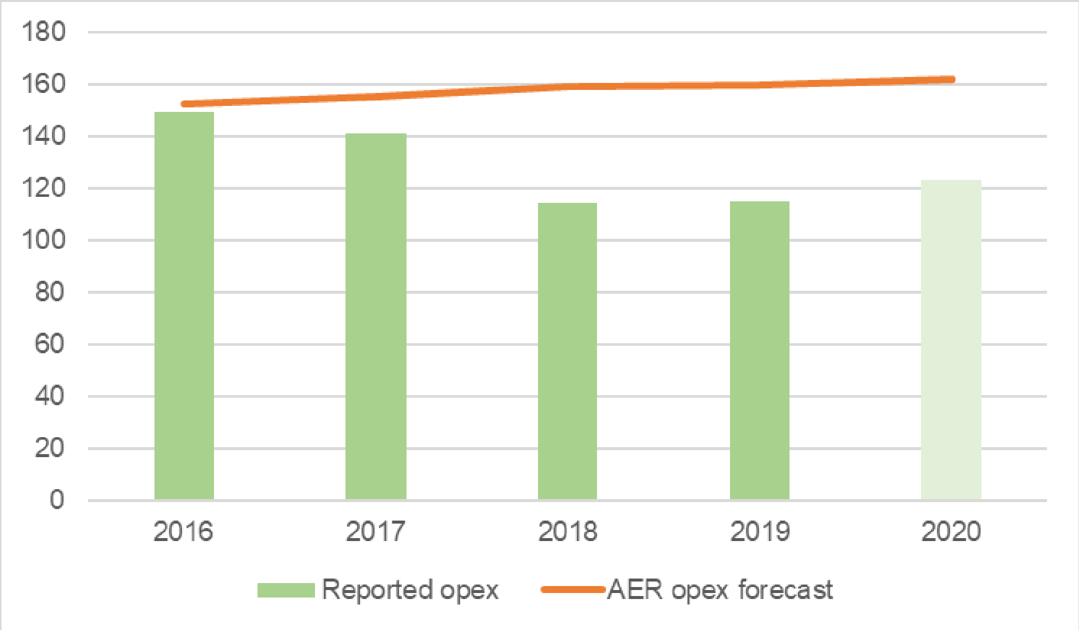
74 United Energy, *2021–26 Regulatory Proposal,* January 2020, p. 140.

75 United Energy, *2019 – Annual – RIN Response – Consolidated*, April 2020.

76 United Energy, *2021–26 Regulatory Proposal, January 2020*, p. 140.

77 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 152.

Figure 6.4 Comparison of United Energy's reported opex and our forecast ($ million, 2020–21)



Source: United Energy, *UE RIN001 – Workbook 1 – Reg determination*, January 2020; United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model*, January 2020; AER analysis.

We have used a variety of economic benchmarking tools to test the efficiency of United Energy's opex. 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 annual benchmarking reports include 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 NEM.[78]

Our preferred approach is to benchmark a business's efficiency on the basis of its performance over time (using a period-average efficiency score from our econometric and opex multilateral partial factor productivity (MPFP) models). We consider that this is a better approach than looking at the efficiency of a single year (such as the base year) as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility.

Our benchmarking results show that United Energy has performed relatively well amongst distributors in the NEM over the last twelve years. Our *2019 Annual Benchmarking Report* shows relative to other regulated distributors in the NEM, United Energy:

[78] AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019.

- was second[79] in terms of multilateral total factor productivity (MTFP) which measures the relationship between total output and total input (i.e. capital assets and opex)
- was ranked fourth in terms of opex efficiency when measured using our econometric models and opex multilateral partial factor productivity (MPFP)[80] over the period 2006–18 and fifth over the period 2012–18[81]
- performed well for various total cost and cost category partial performance indicators (PPIs) over the four year period 2014–18. The exception is average emergency response spend per circuit km where it was one of the poorer performers.[82]

As a result of some recent updates to the economic benchmarking data, and the correction of a coding error in the estimation of the output weights used in the productivity index measure, we have examined the impact of these changes on our benchmarking. We asked Economic Insights to examine the impact of these changes on the 2019 Annual Benchmarking report.[83] While the updates and corrections result in some changes, including to the opex MPFP rankings of some distribution businesses, they do not impact our conclusion of United Energy's base efficiency assessment.

Our analysis shows that United Energy has performed relatively well in our benchmarking results and that it has operated within the opex forecast set by us. For this draft decision we have used United Energy's base year opex in our alternative estimate.

6.4.2 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.[84] As a result of the six month extension to the current regulatory control period, we have updated our final year increment calculation by exchanging the opex forecast for the final year of the preceding regulatory control period to the annualised half year 2021 forecast.

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79 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 13.

80 MPFP examines the productivity of opex and capex in isolation. Opex MPFP considers the productivity of the distributor's operating expenditure.

81 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019. pp. 29–30.

82 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019. pp. 33–40.

83 Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report,* 24 August 2020. The data updates include revised opex data for Jemena, CitiPower, Powercor and AusNet Services in some recent years. The updated weights for non-reliability outputs reflect Economic Insights' review of a report submitted by CitiPower, Powercor and United Energy on opex input price and output weights and the identification of a coding error. See Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020. We are currently consulting with businesses in relation to the updated output weights as a part of our annual benchmarking update to prepare the 2020 Annual Benchmarking Report.

84 AER, *Expenditure forecast assessment guideline,* November 2013. pp. 22–23.

6.4.3 Base adjustments

Minor Repairs – United Energy

United Energy proposed adding $26.2 million ($2020–21) to their base opex for the reclassification of minor repair costs from capex to opex. It currently capitalises this expenditure as replacement expenditure (repex). We are satisfied that it is appropriate to reclassify most of the types of minor repairs proposed by United Energy as opex, rather than capex and have included $17.5 million ($2020–21) in our alternative opex estimate. This is $8.7 million ($2020–21) less than proposed by United Energy. Our reasons for the difference are set out below.

Table 6.5 Minor repairs reclassification ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's Proposal	5.2	5.2	5.2	5.2	5.2	26.2
AER draft decision	3.5	3.5	3.5	3.5	3.5	17.5
Difference	–1.7	–1.7	–1.7	–1.7	–1.7	–8.7

Source: United Energy, *Regulatory proposal 2021–26*, January 2020, p. 152; AER analysis.
Note: Numbers may not add up to total due to rounding.

United Energy proposed reclassifying minor repair costs as opex, rather than capex, because doing so better reflects the nature of the expenditure.[85] United Energy stated that minor repair costs cover repairs:

- due to an asset failure
- for identified defects that could result in an imminent asset failure (if not repaired).

United Energy's proposed base adjustment is based on its actual 2019 minor repairs expenditure for the current regulatory control period.

We engaged EMCa to review the proposed treatment of minor repairs as opex. EMCa considered United Energy's minor repairs definition was problematic as parts of the definition were circular, concluding it does not provide a clear auditable definition of minor repairs to distinguish when a repair is capex or opex.[86]

Despite the definitional issues, EMCa's analysis of information provided by United Energy found the minor repairs work descriptions in conjunction with the low average unit costs and high volumes supported their reclassification as opex. As set out in Table 6.6 , the five year average unit cost of the minor repairs is under two thousand dollars. EMCa noted this compares well to SA Power Network's average

[85] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 153.

[86] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure,* August 2020, p. 217.

unit cost of around four thousand dollars for minor repairs, which EMCa reviewed for the AER during the 2020–25 determination for SA Power Networks.[87]

Table 6.6 Analysis of works proposed by United Energy as 'minor repairs'

	2015	2016	2017	2018	2019	5–year average
Number of repairs	2,451	1,663	2,074	3,868	2,860	2,583
Total cost ($000)	4,337	3,864	4,277	5,147	5,211	4,567
Average unit cost ($)	1,769	2,324	2,062	1,331	1,822	1,768

Source: EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure,* August 2020, p. 219.

EMCa then assessed United Energy's proposed minor repairs cost and proposed an adjustment from $26.2 million ($2020–21) to $17.5 million ($2020–21) for two reasons.

Firstly, EMCa noted minor repair expenditure in 2019 represents a high point. This is illustrated in Table 6.7, which summarises the historical 2015 to 2019 unit costs and volumes of minor repair works provided to EMCa by United Energy. On this basis EMCa recommended a reasonable basis to estimate minor repairs costs would be to use the five year average.[88]

Table 6.7 Historical recast minor repairs expenditure ($ million, 2020–21)

Repair category	2015	2016	2017	2018	2019	5–year average
Pole top maintenance	0.1	0.0	0.0	0.1	0.1	0.1
Pole inspection and treatment	0.0	0.0	0.0	0.1	0.1	0.0
Conductor connector works	0.0	0.0	0.0	0.0	0.1	0.0
Underground cable maintenance	2.8	3.1	3.3	3.7	4.1	3.4
Service line clearance rectification	1.1	0.7	0.6	0.9	0.6	0.8
SCADA89	0.0	0.0	0.0	0.0	0.0	0.0
Fencing repairs	0.3	0.0	0.2	0.2	0.3	0.2
Fargo sleeve repair	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	4.3	3.9	4.2	5.0	5.3	4.6

Source: EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure,* August 2020, p. 220.

[87] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure,* August 2020, pp. 218–219.
[88] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure, August 2020*, pp. 221.

Secondly, based on the work descriptions provided by United Energy, EMCa considered the following three types of work involved in the installation of new assets should not be considered as repairs:[90]

- service line compliance rectification work
- fencing repairs that do not meet the definition of repairing 'small sections' of fencing, and
- installing new conductor connectors and new conductor sleeves.

Hence, EMCa considered these work types should not be classified as opex and should be excluded from historical expenditure amounts used to estimate future requirements on the basis they do not meet a reasonable definition of a repair.[91] This results in a revised five year average of $3.5 million ($2020–21) for minor repairs as set out in Table 6.8.

Table 6.8 Historical and average minor repairs, excluding service line compliance rectification and o/h asset inspection ($ million, 2020–21)

Repair category	2015	2016	2017	2018	2019	5–year average
Pole top maintenance	0.1	0.0	0.0	0.1	0.1	0.1
Pole inspection and treatment	0.0	0.0	0.0	0.1	0.1	0.0
Underground cable maintenance	2.8	3.1	3.3	3.7	4.1	3.4
TOTAL	2.9	3.1	3.4	3.9	4.2	3.5

Source: EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure,* August 2020, p. 221.

We agree with EMCa's assessment and we have included $17.5 million ($2020–21) in our alternative estimate for the reclassification of minor repairs, based on the annual five year historical average of $3.5 million ($2020–21). The use of a five year average to estimate costs by EMCa is consistent with our standard approach.

We have not included the remainder of the activities in capex either, as based on the information before us, the additional activities are embedded in United Energy's historical repex. United Energy has not explained why it has included the additional repair activities beyond what is already included in its repex forecast.

Wasted Truck Visits

United Energy proposed adding $1.1 million ($2020–21) to their base opex for the reclassification of wasted truck visits for network faults that turn out to be due to faults on the customer's side of the meter. We are satisfied that it is appropriate to include

90 EMCa *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 221.

91 EMCa *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 221.

this expenditure in the base opex in our alternative estimate for the reasons set out below.[92]

We consider United Energy's proposed reclassification is consistent with the changes to the classification of wasted truck visits in our Framework and Approach (F&A) paper.[93] We also consider the costs proposed are appropriate because they are based on historical costs which appear reasonable.

We note United Energy has sought to minimise wasted service truck visits by using the data provided by advanced metering infrastructure (AMI) meters to first investigate if there are any voltage issues or if their customers are off supply. Additionally, when the customer reports a fault, call centre agents will try to troubleshoot with United Energy's customers prior to issuing a service truck.[94]

AMI Communications Network

United Energy proposed adding $4.7 million ($2020–21) to their base opex for the reclassification of their communications network opex expenditure from alternative control to standard control services. We are satisfied that it is appropriate to partially include this expenditure in our alternative estimate and have made a $1.3 million ($2020–21) base adjustment.[95]

United Energy's proposal outlined that the proposed reallocation of operating expenditure was based on a causal driver of meter data volumes. Their proposed allocation was an adjustment to 88.0 per cent for standard control services (SCS) and 12.0 per cent for alternative control services (ACS) based off the proportion of meter data collected for SCS purposes relative to ACS purposes.[96]

We do not accept that the proposed meter power quality data volumes in United Energy's proposal are justified. For our alternative estimate we have allocated AMI costs as 25.0 per cent for SCS and 75.0 per cent for ACS. Further details, including the reasons for our approach, are set out in Attachment 16.

6.4.4 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.[97]

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92 United Energy, *2021–26 Regulatory Proposal, January 2020*, pp. 152–153.

93 AER, *Final Framework and Approach for AusNet Services, CitiPower, Jemena, Powercor and United Energy*, January 2019, p. 32.

94 United Energy, *Information request 45 – Opex base adjustments*, 29 June 2020, p. 2.

95 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 152–153.

96 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 185–186; United Energy, *Information request 58 – AMI communications cost allocation,* 28 July 2020.

97 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–24.

United Energy broadly applied our standard approach to forecasting the rate of change. It proposed:

- **Price growth:** to adopt firm specific input price weightings of 58.2 per cent labour and 41.8 per cent non-labour and to forecast labour price growth using only BIS Oxford Economics' wage price index (WPI) growth forecasts. It also added the legislated superannuation guarantee increases to its labour price growth forecasts.[98]
- **Output growth:** to apply the weights from our two Cobb Douglas econometric models (but not our translog or MPFP models) rather than the output weights from all five economic benchmarking models adopted in our most recent determinations.[99]
- **Productivity growth:** to use our 0.5 per cent per year productivity growth forecast.[100]

The rate of change proposed by United Energy contributed $39.1 million ($2020–21), or 5.0 per cent, to United Energy's total opex forecast of $785.9 million ($2020–21). This equates to opex increasing by 1.9 per cent each year.[101] We include a rate of change that increases opex by 0.5 per cent each year in our alternative estimate. We discuss the differences between our forecast and United Energy's forecast below.

Table 6.9 Forecast rate of change, per cent

	2021–22*	2022–23	2023–24	2024–25	2025–26
United Energy's proposal					
Price growth	1.2	1.3	1.3	1.1	1.0
Output growth	1.2	1.2	1.1	1.3	1.4
Productivity growth	0.5	0.5	0.5	0.5	0.5
Overall rate of change	1.9	2.0	1.9	1.9	1.9
AER draft decision					
Price growth	0.1	–0.1	0.0	0.2	0.6
Output growth	0.5	0.9	1.0	1.0	1.0
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	0.3	0.2	0.5	0.7	1.1
Overall difference	–1.6	–1.8	–1.5	–1.2	–0.9

98 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 154–157.
99 United Energy, *2021–26 Regulatory proposal*, January 2020, pp. 157–160.
100 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 160–162.
101 United Energy, *2021–26 Regulatory Proposal – Supporting document 10.06 – Opex model*, January 2020.

* The rate of change for 2021–22 reflects nine months' worth of growth in price, output and productivity. We discuss the reasons for this below.

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model,* January 2020; AER analysis.

We received five submissions relating to the proposed rate of change.[102] The key concern raised by stakeholders was the impact of the COVID–19 pandemic on the accuracy of the forecasts. We have taken these concerns into account by relying on Deloitte's WPI growth forecasts only, and updating the forecasts for three of the individual output measures.

Forecast price growth

We have included forecast average annual real price growth of 0.2 per cent in our alternative estimate. This compares to United Energy's proposed average annual price growth of 1.2 per cent.[103] This increases our alternative estimate of total opex by $1.3 million ($2020–21), instead of $23.6 million ($2020–21) as proposed by United Energy.

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 most up-to-date forecast of growth in the WPI for the Victorian electricity, gas, water and waste services (utilities) industry as forecast by Deloitte.[104] United Energy used the WPI growth forecasts for Victoria from BIS Oxford Economics.[105] Our standard approach is to use an average of the forecasts from Deloitte and those proposed by the distributor. We discuss below our reasons for not averaging the Deloitte forecasts with the forecasts from BIS Oxford Economics. Like United Energy, we have accounted for the legislated superannuation guarantee increases in our labour price growth forecasts.
- Both we and United Energy applied a forecast non-labour real price growth rate of zero.[106]
- We applied benchmark input price weights of 59.2 per cent and 40.8 per cent for labour and non-labour, respectively. These weights correct for a small error in the

102 CCP17, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, 10 June 2020, pp. 56–58; Origin Energy, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26,* 3 June 2020, pp. 4–5; Energy Australia, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26,* 3 June 2020, p. 7; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, June 2020 p. 30; Victorian Community Organisations, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, May 2020, pp. 62–64.

103 United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model*, January 2020.

104 Deloitte Access Economics, *Wage price index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020.

105 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 154.

106 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 154.

calculation used to determine the weights we have previously used.[107] United Energy applied firm specific input price weights of 58.2 per cent labour and 41.8 per cent non-labour.[108]

We have set out the reasons for the differences between our real price growth forecasts and United Energy's below.

Deloitte's forecasts of utilities real WPI growth for Victoria reflect the best estimate of labour real price growth at this time

We have only used forecasts from Deloitte, rather than real WPI growth forecasts from BIS Oxford Economics. While our preferred approach is to use an average of the utilities real WPI growth forecast, we have not included the BIS Oxford Economics forecast as it was produced prior to the COVID–19 pandemic and does not reflect a realistic expectation of labour prices.

In previous decisions we have forecast labour price growth by using an average of the utilities industry real WPI growth forecasts for the relevant state provided by a consultant engaged by us (Deloitte) and the forecasts submitted by the network business (often BIS Oxford Economics). We adopted this approach after testing the accuracy of the forecasts from both consultants. We found, at that time, that an average of the two forecasts was closer to actual utilities WPI growth than either of the individual forecasts.[109] In our draft decision for SA Power Networks for its 2020–25 regulatory control period we reconsidered whether this was best approach.[110] In the final decision we concluded using an average of the two sets of forecasts was most likely to produce the most accurate forecast of labour price growth. In reaching that position we took into account that:[111]

- Deloitte’s national utility WPI forecasts have been more accurate than BIS Oxford Economics over the period 2007–2018, however forecasts made prior to 2014 appear to have not anticipated the wage growth slowdown that started around that time, impacting the results of our analysis
- similar analysis for Victoria, for which we have utilities WPI data, found that Deloitte had under forecast utilities WPI growth, BIS Oxford Economics had over forecast and that an average of the two had been most accurate

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[107] Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 8.

[108] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 156; United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model*, January 2020.

[109] AER, *Access arrangement draft decision, SPI Networks (Gas) Pty Ltd 2013–17, Part 3, Appendices*, September 2012, pp. 78–81.

[110] AER, *Draft decision, SA Power Networks distribution determination 2020–2025, Attachment 6 Operating expenditure*, October 2019, pp. 29–32.

[111] AER, *Final decision, SA Power Networks distribution determination 2020–2025,, Attachment 6 Operating expenditure*, June 2020, pp. 14–19.

- the economic literature generally supports using an average of the available forecasts.

United Energy engaged Frontier Economics to assess the accuracy of BIS Oxford Economics forecasting history for Victorian real utilities WPI. United Energy stated that Frontier Economics found that BIS Oxford Economics had been more accurate than Deloitte.[112] However Frontier Economics concluded that we should revert to using the average of forecasts produced by different advisers when forecasting real labour price growth.[113]

Frontier Economics considered that a significant body of forecasting literature concludes that forecast accuracy can be improved substantially by combining forecasts from different sources. Thus for Victoria, Frontier Economics concluded the evidence suggests that the average of the two sets of forecasts 'would have resulted in more accurate outcomes than exclusive reliance on either of those advisers' forecasts individually'.[114]

We note that Frontier Economics appears to have reached the conclusion that BIS Oxford Economics had been more accurate than Deloitte at forecasting real WPI growth for the Victorian utilities industry on the basis of a lower mean absolute error. The difference between the mean absolute errors for the two forecasters is small (0.52 compared to 0.55). Frontier Economics itself states that this result suggests that BIS Oxford Economics has tended to forecast the real growth in the Victorian utilities WPI 'slightly more accurately' than Deloitte.[115]

We consider that Frontier Economics reached broadly the same conclusion as we did in our final decision for SA Power Networks. That is, we should use an average of the forecasts from Deloitte and BIS Oxford Economics to forecast WPI growth for similar reasons.

Deloitte and BIS Oxford Economics forecasts

There is a significant difference between the WPI growth forecasts provided by Deloitte, who we engaged, and those provided by BIS Oxford Economics, who was engaged by United Energy (see Table 6.10).

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112 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 154.

113 Frontier Economics, *Assessment of the AER's approach to forecasting labour escalation rates*, 19 December 2019, p. 2.

114 Frontier Economics, Assessment of the AER's approach to forecasting labour escalation rates, 19 December 2019, p. 2.

115 Frontier Economics, Assessment of the AER's approach to forecasting labour escalation rates, 19 December 2019, p. 17.

Table 6.10 Forecast utilities WPI growth for Victoria, per cent

	2021–22	2022–23	2023–24	2024–25	2025–26
Deloitte	–0.3	–0.7	–0.6	–0.1	0.5
BIS Oxford Economics	1.5	1.7	1.7	1.5	1.3

Source: Deloitte, *Wage price index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020, p. xv; BIS Oxford Economics, *Labour cost escalation forecasts 2025–26*, April 2019, p. 5.

A key reason for this difference is BIS Oxford Economics forecasts were prepared prior to the COVID–19 pandemic which has materially changed the economic outlook. United Energy's proposal stated that:[116]

> Labour price growth over the 2021–2026 period will be buoyant as a result of strong population growth and a rebounding economy. Victoria's population, particularly in Melbourne, is expected to be stronger than the national average as migration from interstate increases. Victoria's economy is expected to rebound from stronger population growth, higher exports and household consumption from the weak Australian dollar, and stronger business investment.

Deloitte's forecasts were prepared in late July 2020 and take into account the effects of the COVID–19 pandemic. Deloitte stated in its report that:[117]

> The Victorian economy experienced strong growth momentum prior to the outbreak of COVID–19. The state's economy was supported by high rates of population growth, low interest rates and strong public sector investment. The introduction of COVID–19 restrictions from March 2020 has weighed heavily on migration, international student commencements, as well as overall economic activity. The July 2020 spike in COVID–19 infections has also led to the reintroduction of tight containment measures in Victoria.

Deloitte further note that Victoria currently has the strongest COVID–19 restrictions of any Australian jurisdiction. It considered that the 'the short-term outlook is particularly weak as Victorians reduce consumption amid a rapidly changing and uncertain COVID–19 outbreak.'[118]

The difference in the economic outlook underlying the two sets of forecasts is stark. We consider that the BIS Oxford forecasts do not reflect a realistic expectation of labour prices. Nor would including them in an average produce a realistic expectation of labour prices. Consequently we have used only the Deloitte forecasts to forecast

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116 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 155.

117 Deloitte Access Economics, *Wage price index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020, p. 15.

118 Deloitte Access Economics, *Wage price index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020, p. 15.

labour price growth for this draft decision as this reflects the best estimate available at this time. If we have BIS Oxford Economics' updated forecast that accounts for the significant shift in the economic outlook for our final decision we will reconsider averaging them with updated Deloitte forecasts, having regard to the reasons described above.

We have accounted for the legislated increases in the superannuation guarantee in our labour price growth forecasts

United Energy added an additional allowance for the legislated superannuation guarantee increases to its labour price growth forecasts. United Energy stated that, according to BIS Oxford Economics' research, the superannuation payments are not included in the WPI. It stated that the superannuation guarantee increase, therefore, should be added to the forecast increases in the WPI to forecast labour price growth.[119]

Although the BIS Oxford Economics report states that the WPI does not include superannuation, it does not state whether or not the forecast superannuation guarantee increases should be added to forecast WPI growth. Nor does it state how it has accounted for the legislated superannuation guarantee increases in its WPI growth forecasts.

We sought advice from Deloitte on how to best account for the superannuation guarantee increases. It noted that there is extensive research suggesting that increases in payroll taxes or compulsory contributions levied on employers are passed onto employees. This research suggests the increases to the superannuation guarantee will likely result in slower WPI growth than would otherwise have been the case. Deloitte advised that the superannuation guarantee increases should be added to the forecast WPI growth rates, but only if those WPI growth rates take into account the superannuation guarantee changes.[120] Consequently we have added the legislated superannuation guarantee increases to Deloitte's WPI growth forecasts to forecast labour price growth.

Consistent with the advice of Deloitte we sought to confirm whether BIS Oxford Economics' WPI growth forecasts are lower than they would have been had the superannuation guarantee increases not been legislated. United Energy's response simply restated that the WPI does not include superannuation and therefore the superannuation guarantee increases should be added to forecast WPI growth.[121] Given we could not establish whether BIS Oxford Economics' WPI growth forecasts are lower than they would have been had the superannuation guarantee increases not been legislated, it remains unclear whether it would be appropriate to add the superannuation guarantee increases to BIS Oxford Economics' WPI growth forecasts.

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[119] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 155.

[120] Deloitte Access Economics, *Impact of changes to the superannuation guarantee on forecast labour price growth*, 24 July 2020.

[121] United Energy, *Information request 48 – Forecast price growth*, 6 July 2020.

As discussed above, we don't consider BIS Oxford's forecasts reasonably reflect the current economic outlook, and thus we have not used them for this draft decision. Should United Energy provide revised BIS Oxford's forecasts with its revised proposal we would only add the legislated superannuation guarantee increases to them if it is clear they have been reduced to account for the superannuation guarantee increases.

We have used industry average input price weights

We have used the weights of 59.2 per cent for labour inputs and 40.8 per cent for non-labour inputs. Our input price weights reflect the weights we used in our *2019 Annual benchmarking report*, corrected for an error identified by Frontier Economics.

United Energy used the weights of 58.2 per cent for labour inputs and 41.8 per cent for non-labour inputs, based on its average reported mix of labour and non-labour inputs over the period 2014 to 2018.[122]

United Energy submitted a report from Frontier Economics,[123] which advocated for the use of firm specific 'actual' input weights, rather than the industry-wide weights we use. Firstly, it is worth noting that the term 'actual' is something of a misnomer. As highlighted by our consultant Economic Insights, the prevalence of contracting by distributors means that they do not typically have accurate data on the input mix employed by the contractors they engage. For this reason, like Economic Insights, we prefer to use the term 'reported' weights.[124]

We maintain the view that it is appropriate to use industry average input price weights, rather than firm-specific reported weights. We previously considered whether to use firm-specific input price weights in our determinations for CitiPower and Powercor for their 2016–20 regulatory control periods.[125] We maintain the views expressed in that decision. In particular, using a firm's revealed input would remove the incentive for it to adopt a more efficient input mix. It would instead have an incentive to use more of the input that is forecast to increase in price more rapidly. Consequently, using a distributor's revealed input mix would not provide it with effective incentives in order to promote economic efficiency[126] and would not be in the long term interest of consumers.[127] This is because minimising price growth would not only reduce base opex, but would also reduce the opex rate of change.

122 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 155–157.

123 Frontier Economics*, Estimation of opex input weights*, 15 March 2019.

124 Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 3.

125 AER, *Final decision, CitiPower distribution determination 2016–2020, Attachment 7 Operating expenditure*, May 2016, pp. 86–89.

126 NEL, s. 7A(3).

127 NEL, s. 7.

This conclusion is supported by analysis done by PricewaterhouseCoopers (PWC) for ElectraNet.[128] PWC's analysis was done in the context of forecasting productivity growth, but the logic applies equally to the other components of the rate of change. PWC demonstrated that using a firm's revealed efficiency gains to both set base opex and to forecast productivity growth, would substantially diminish the reward from reducing opex. It stated that, 'in effect, the incentive properties ordinarily provided by the regulatory framework would be almost entirely eliminated'.[129]

It is important to note that we do not oppose using United Energy's reported input mix because we consider it to be 'inefficient'. The input mixes of the distributors that perform well in our benchmarking varies. We don't consider there to be a single 'efficient' input mix. Consider two hypothetical distributors that are identical aside from the fact one uses a higher proportion of labour in its inputs. Under the approach proposed by United Energy one distributor would receive a higher opex forecast when it is otherwise identical to the other distributor.

We engaged Economic Insights to consider the issues raised by Frontier Economics.[130] Economic Insights recommended that we maintain our existing approach of using an industry average. In summary, Economic Insights considered:[131]

- Frontier Economics' report overlooked the interaction between price growth and productivity growth. Economic Insights concluded that if the opex productivity component of the rate of change is based on industry-wide information then the opex price weights should also be based on industry-wide information to maintain consistency and reduce perverse incentives.
- Frontier Economics criticised our use of industry average price weights inputs based on 2017 distributor data due to the difficulties distributors had in allocating contracted services between labour and non-labour components. To deal with this at the time we extrapolated the input weights for contracted services from those that did report them. Economic Insights stated that, while not perfect, this was the best strategy for making the most reasonable estimates based on the information available. Additionally it noted Frontier Economics' criticisms highlight the difficulty in obtaining reliable and consistent information in this area. Economic Insights was surprised Frontier Economics advocated the use of firm specific reported data at the same time it was critical of the information the distributors supplied.
- However, Economic Insights agreed that one of the calculation errors identified by Frontier Economics was an error. Correcting this error reduces the industry average labour weight from 59.7 per cent to 59.2 per cent.

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128 PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013.

129 PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013, pp. 7–8.

130 Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020.

131 Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, pp. 5–8.

Given the above considerations, we maintain the view that we should continue to use the industry average input mix, rather than a firm specific mix, to forecast input price growth. However, consistent with Economic Insights' advice, we have corrected the error in the calculation of the industry average input weights identified by Frontier Economics.

Forecast output growth

We have included forecast average annual output growth of 0.9 per cent in our alternative opex estimate. This compares to United Energy's proposed average annual output growth of 1.3 per cent.[132] This increases our alternative estimate of total opex by $15.3 million ($2020–21), instead of $25.3 million ($2020–21) as proposed by United Energy.

We have forecast output growth by:

- Calculating the growth rates for four outputs (customer numbers, circuit line length, energy throughput, and maximum demand). United Energy used the same output measures, except it did not use energy throughput.
- Calculating five weighted average overall output growth rates using the output weights from the five models presented (see Table 6.11). In doing so we made adjustments and corrections to address issues raised by Frontier Economics and United Energy. United Energy used only the two Cobb-Douglas models.
- Averaging the five model specific weighted overall output growth rates.

Table 6.11 Output weights, per cent

	Cobb-Douglas SFA	Cobb-Douglas LSE	Translog LSE	Translog SFA	MPFP	Average	United Energy proposed
Customer numbers	67.4	69.0	38.0	69.7	18.5	52.5	69.2
Circuit length	15.1	15.6	21.2	12.4	39.1	20.7	14.3
Ratcheted maximum demand	17.5	15.5	40.9	17.9	33.8	25.1	16.5
Energy throughput	–	–	–	–	8.6	1.7	–

Source: Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 21; United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 159.

We will publish our *2020 Annual benchmarking report* in late November 2020. In our final decision, we will update our output growth rate forecasts to reflect the results in

[132] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 160.

the *2020 Annual benchmarking report*. Full details of our approach to forecasting output growth are set out in our opex model, which is available on our website.

United Energy proposed that, instead of using all five models from our annual benchmarking report we should only use the two Cobb Douglas models. Specifically, it considered we shouldn't use the opex multilateral partial factor productivity model or the two translog models. It adopted this approach based on advice it received from NERA and Frontier Economics.[133]

Our reasons for using the output weights from all five models, and not just the Cobb-Douglas models, are set out below.

We are also not satisfied that United Energy's forecasts of the individual outputs reasonably reflect a realistic expectation of the growth in those outputs. Our reasons for using alternative forecasts of the individual outputs are also set out below.

MPFP is an appropriate model for forecasting output growth

Issues raised by NERA

NERA considered that our opex MPFP model was an unreliable measure of the drivers of cost of an efficient operator because it considered:[134]

- the process for deriving weights from the MPFP modelling is not transparent
- the drivers included in the MPFP modelling were chosen based on tariff structure, not by assessing their effect on distributors' costs
- the weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model
- the MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely.

SA Power Networks submitted the same report from NERA with its proposal for its 2020–25 regulatory control period. We considered the issues raised by NERA in our draft decision for SA Power Networks, which we published in October 2019. Economic Insights, engaged by us, reviewed NERA’s report and outlined several areas of concern in relation to NERA's analysis and proposed approach.[135] We summarised the technical concerns raised by NERA about our approach and Economic Insights' response to each of the concerns in our draft decision for SA Power Networks.[136] United Energy did not address any of the reasons we gave in our draft decision for SA Power Networks, or Economics Insights' report, in its proposal.

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133 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 157.

134 NERA, *Review of the AER's Proposed Output Weightings*, December 2018, pp. ii–iii.

135 Economic Insights, *Review of NERA report on output weights*, 30 April 2019.

136 AER, *Draft decision, SA Power Networks distribution determination 2020–2025, Attachment 6 Operating expenditure* October 2019, pp. 63–64.

NERA also raised concerns about whether energy throughput fully accounts for the impact of distributed energy resources. We consider that it will likely be appropriate to review the output specification used in our benchmarking models. Currently, the energy throughput output variable captures changes in the amount of energy delivered to customers over the distribution network as measured at the customer meter. It does not measure energy delivered into the distribution network via distributed energy resources, such as from residential roof-top solar panels. An increase in roof-top solar panels could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. In this situation there could be a material increase in inputs without a corresponding increase in any or all of the output measures. Under these circumstances, the existing output measures would not allow the distributor to recover prudent and efficient costs associated with a significant change to its operating environment. We acknowledge that more work will need to be done to properly assess this impact.

Similarly, United Energy argued that, according to the MPFP model, opex would decrease with falling energy throughput. It considered that the true relationship between energy throughput and opex is likely to be increasingly negative. That is, as growth in distributed energy resources reduces energy throughput it also imposes additional costs that are not captured in the cost function.[137]

We agree that growth in distributed energy resources may increase opex in some circumstances. But United Energy's argument conflates energy throughput and distributed energy resources outputs. All else equal, increasing energy throughput does not decrease opex. Rather, throughput is potentially negatively correlated to an output missing from our output specification that may increase opex. The solution to the problem, should it be proven, would be to include an additional output covering distributed energy resources, not to remove an existing output.

Our view is that any changes to the output forecasting approach should be made as part of a wider periodic review of economic benchmarking. Further, such a review will not be confined to just removing certain outputs—it will need to consider adding new outputs as well as removing any obsolete outputs to refine the forecasting approach. Such a review would also need to consider the data requirements for any new output specification.

In the meantime, to the extent that our output specification may not fully account for growing distributed energy resources, we will consider additional costs imposed by an increasing uptake of distributed energy resources as step changes. In particular, we have assessed United Energy's proposed step change relating to solar enablement that is driven by increasing use of distributed energy resources in its network. In this

[137] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 158.

instance we have not accepted the proposed step change for the reasons outlined in section 6.4.5. It would be inappropriate to take into account distributed energy resources in our output specification via output growth, and as a step change for it at the same time.

Issues raised by Frontier Economics

Frontier Economics considered there were statistical problems with the results of the opex MPFP model. It also identified a coding error in the calculations.[138]

Economic Insights reviewed the issues raised by Frontier Economics and agreed there was a coding error in its calculations.[139] Economic Insights found correcting this error significantly improves the performance of the opex MPFP model and consequently mitigates the statistical problems raised by Frontier Economics about the opex MPFP model.[140] Consequently, Economic Insights considered we should include the MPFP weights when we forecast output growth.[141] We agree with Economic Insights that correcting the coding error addresses the concerns raised by Frontier Economics and, consequently, the MPFP model should be included in our forecast of output growth.

The output cost weights in the opex MPFP model were updated by Economic Insights in 2018 based on estimation over the period 2006 to 2017.[142] The intention had been to use these weights for approximately five years. Given we now have an extra year of data, Economic Insights included the extra data when it re-estimated the models after correcting the coding error.

The effect of correcting the error on the output cost weights is shown in Table 6.12. The effect is to transfer weight from customer numbers to circuit length, and to a lesser extent from energy throughput to ratcheted maximum demand.

Table 6.12 Corrected opex MPFP output weights, per cent

	Uncorrected, 2006–2017	Corrected, 2006–2018
Energy throughput	12.46	8.58
Ratcheted maximum demand	28.26	33.76
Customer numbers	30.29	18.52

138 Frontier Economics, *Memorandum prepared for the AER on review of econometric models used by the AER to estimate output growth*, 5 December 2019, pp. 7–15.

139 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, pp. 15–16.

140 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, pp. 15–16.

141 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, pp. 16–17.

142 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Benchmarking Report*, 9 November 2018.

	Uncorrected, 2006–2017	Corrected, 2006–2018
Circuit length	28.99	39.14

Source: Economic Insights, *Memorandum prepared for the AER review of reports submitted by CitiPower, Powercor and United Energy on opex input price and output weights*, 18 May 2020, p. 16.

We agree with Economic Insights that correcting the coding error addresses the concerns raised by Frontier Economics and, consequently, we have included the opex MPFP model (along with the other four models) in our forecast of output growth.

Translog models are appropriate for forecasting output growth

Our past practice has been to evaluate the elasticities from our translog models at the average output levels of all distributors in the international sample. Frontier Economics, in its report for United Energy, considered the use of an international sample was not appropriate due to the different output levels. Frontier Economics considered the elasticities should be evaluated at output levels that reflect the operating characteristics of Australian distributors and this could be done better using the Cobb-Douglas function. On this basis, United Energy did not use the translog models to derive their proposed output weights.[143]

Our consultant Economic Insights reviewed the issues raised by Frontier Economics. It advised the translog models should be retained in the calculation of output weights because the translog function is more flexible than the Cobb Douglas function and so produces additional useful information that should be included.[144]

Economic Insights stated that it has no underlying objection to calculating the output weights at the Australian average level rather than at the average output levels of all distributors in the international sample.[145] It demonstrated that there is economic justification for using both bases and the statistical performance of the models using either basis is similar.[146]

In table 6.13 below we present the output weights derived from the translog opex cost functions with data normalised by the full sample means and by the Australian sample means, as calculated by Economic Insights. As noted by Economic Insights, the basis of normalisation does not make a material difference to the output weights derived from the stochastic frontier analysis (SFA) estimation method. However, for the least squares econometrics (LSE) method the effect of normalising by the Australian sample

143 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 159.

144 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.

145 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. 19.

146 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.

means is to transfer weight from customer numbers to line length and ratcheted maximum demand.[147]

Table 6.13 Translog opex cost function output weights, per cent

Output	LSE All DNSPs	LSE Australian DNSPs	SFA All DNSPs	SFA Australian DNSPs
Customer numbers	52.95	37.95	69.45	69.73
Circuit length	15.72	21.16	14.86	12.37
Ratcheted maximum demand	31.33	40.89	15.69	17.90

Source: Economic Insights, *Memorandum perpared 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. 19.

We agree with Economic Insights that we should retain the translog models as they provide additional useful information. To address Frontier Economics' concern that an international sample mean is not appropriate, we have used the translog opex cost function output weights at Australian average output levels, as set out in table 6.13.

Forecast growth of the individual output measures

We are not satisfied that United Energy's forecast of the growth in customer numbers, maximum demand and energy throughput reasonably reflect a realistic expectation. We have used in our alternative estimates forecasts which we consider reflect a more realistic expectation. Specifically:

- **Customer numbers:** we have adjusted United Energy’s forecasts, produced pre-COVID–19, in line with the reduction we have applied to customer connections. The adjustment reflects the Housing Industry Association’s April 2020 dwelling starts forecasts. We discuss this further in Attachment 5.
- **Ratcheted maximum demand:** we forecast ratcheted maximum demand based on AEMO’s 2019 maximum demand forecasts at the transmission connection point. AEMO is not forecasting demand to surpass its historic peaks in the 2021–26 regulatory control period, indicating no growth in ratcheted maximum demand. We discuss our maximum demand forecasts further in Attachment 5.
- **Energy throughput:** United Energy forecast energy throughput growth of around 0.5 per cent per year. Over the period 2006–18 actual energy throughput growth has averaged –0.2 per cent. Further, AEMO's, forecast of energy throughput at the state level in its 2019 Electricity statement of opportunities is no more than the

[147] 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.

historic average.[148] Consequently we have used United Energy's historic average growth rate to forecast energy through.

Table 6.14 Forecast growth in outputs, per cent

	2021–22	2022–23	2023–24	2024–25	2025–26
United Energy's proposal					
Customer numbers	1.5	1.4	1.4	1.3	1.2
Circuit Length	1.3	1.4	1.4	1.5	1.6
Ratcheted maximum demand	–	–	–	0.9	2.0
Energy throughput	0.3	0.5	0.5	0.5	0.5
AER draft decision					
Customer numbers	0.6	1.1	1.4	1.3	1.2
Circuit Length	1.0	1.4	1.4	1.5	1.5
Ratcheted maximum demand	–	–	–	–	–
Energy throughput	–0.2	–0.2	–0.2	–0.2	–0.2

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 159; United Energy, *Reset RIN, Workbook 1, UE RIN001*, January 2020; AEMO, *Transmission connection point forecasts*, November 2019; AER analysis.

Forecast productivity growth

We have forecast productivity growth of 0.5 per cent per year in developing our alternative opex forecast. United Energy also included forecast productivity growth of 0.5 per cent per year in its opex forecast.[149] This reduces our alternative estimate over the 2021–26 regulatory control period of total opex by $8.7 million ($2020–21), instead of $9.9 million ($2020–21) as proposed by United Energy.

Forecasting the rate of change for 2021–22

We have amended how we forecast the rate of change for 2021–22 to account for the shift from calendar years to financial years. To forecast our alternative estimate of opex we apply the rate of change to our annualised estimate of opex for the first six months of 2021.

The rate of change for 2021–22 should represent the change in the average level of output, prices and productivity in that year compared to the first six months of 2021 (the six month extension period). This can be thought of as the difference between the levels at the end of December 2021 (the middle of 2021–22) and the end of March

[148] AEMO, *2019 Electricity Statement of Opportunities*, August 2019, p. 106.

[149] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 160.

2021 (the middle of the 2021 half year). This is nine months. This is consistent with the approach we have used to set forecast opex for the six month extension period.

6.4.5 Step changes

In developing our alternative estimate, we typically include step changes for cost drivers such as new regulatory obligations or efficient capex/opex trade-offs. As we explain in the Expenditure Forecast Assessment Guideline, we will include a step change if the efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.[150]

United Energy proposed nine step changes totalling $85.6 million ($2020–21) or 10.7 per cent of its proposed total opex forecast, including the EPA regulation step change which was withdrawn on 15 May 2020.[151] These are shown in Table 6.15 along with our draft decision, which is to include three step changes in our alternative estimate totalling $40.6 million ($2020–21).

Table 6.15 United Energy proposed step changes and our draft decision ($ million, 2020–21)

Step change	United Energy proposed step changes	AER draft decision	Difference
Security of critical infrastructure	45.9	32.4	–13.5
EPA regulations change	11.8	–	–11.8
Demand management programs	8.6	–	–8.6
IT cloud solutions	4.7	4.5	–0.2
Solar enablement	4.2	–	–4.2
5 minute settlement	3.9	3.7	–0.3
ESV levy	2.5	–	–2.5
Increasing insurance premiums	2.2	–	–2.2
Financial year RIN	1.8	–	–1.8
Total	85.6	40.6	–45.1

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 144,148; AER analysis.

Note: Numbers may not add up to total due to rounding.

The following sections set out the reasons for our draft decision.

150 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

151 United Energy*, 2021–26 Regulatory proposal – Supporting document 10.06 – Opex model*, January 2020

Security of critical infrastructure

United Energy proposed a step change of $45.9 million[152] ($2020–21) in response to the introduction of a series of requirements by the Australian Government in 2017 to address national security risks of espionage, sabotage and coercion associated with foreign involvement, through ownership, offshoring, outsourcing and supply chain arrangements in critical infrastructure.[153]

Our draft decision is to include an alternative estimate of $32.4 million ($2020–21).

Table 6.16 Security of critical infrastructure step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	10.1	8.8	8.9	9.0	9.1	45.9
AER draft decision	8.2	6.0	6.0	6.1	6.1	32.4
Difference	–1.9	–2.8	–2.9	–3.0	–3.0	–13.5

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

The critical infrastructure requirements relate to system and data controls and to meet these requirements, United Energy must transition to compliance in accordance with the work plan approved by the Australian Government.

In our assessment we took into account confidential information provided by United Energy related to these new Commonwealth obligations. We consider that this proposal meets the Expenditure Forecast Assessment Guideline's expectations for a step change associated with new and major regulatory obligations.[154] These critical infrastructure system obligations are new 'regulatory obligations or requirements' as defined in the National Electricity Law (NEL)[155] and are associated with the provision of standard control services. These obligations impose a major shift in the way United Energy must operate and control its network. The driver for this step change is out of the distributor's control. These obligations are expected to have a major impact as they require United Energy to address its current noncompliance as well as to comply fully with the new obligations during the next regulatory control period.

Whilst we are satisfied that there is a prudent driver for the proposal, we have assessed the costs proposed based on the confidential information provided and included a reduced amount of $32.4 million ($2020–21) in our alternative estimate.

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152 United Energy, *2021–26 Regulatory Proposal,* January 2020, p. 144.

153 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 145.

154 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–55; AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

155 NEL, s. 2D.

Our reasons for this are set out in confidential Appendix A as it contains commercially sensitive information and the Foreign Acquisition and Takeovers Act 1975 (FATA) restricts disclosure of protected information.

We expect United Energy to both update its forecast in its revised proposal following the results of a competitive tender process to ensure its approach is seeking the least cost option and update its cost estimate based on our assessment findings.

Environment Protection Amendment Act 2018

United Energy proposed a step change of $11.8 million ($2020–21) to comply with its obligations under the *Environment Protection Amendment Act 2018* (2018 Amending Act).[156] However, it withdrew this proposal (and the associated capex) in its amended proposals submitted on 15 May 2020 as a result of the deferral in the legislation and associated uncertainty of timing.[157]

Accordingly, we have not included this step change in our alternative estimate of total opex.

Table 6.17 EPA step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	3.6	3.4	3.2	1.3	0.4	11.8
AER draft decision	–	–	–	–	–	–
Difference	–3.6	–3.4	–3.2	–1.3	–0.4	–11.8

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

Demand management

United Energy proposed a step change of $8.6 million ($2020–21) for three demand management projects, which are mainly driven by expected growth in maximum demand.[158] We have not included this step change in our alternative estimate of total opex. We discuss our consideration of each demand management project below.
For the reasons outlined, we are not satisfied the proposed step change is required for total forecast opex to reflect the opex criteria.

156 United Energy, *2021–26 Regulatory Proposal,* January 2020, p. 144.

157 Powercor, CitiPower, and United Energy*, Amendments to operating expenditure step changes and capital programs*, 15 May 2020, pp. 1–3.

158 United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model (updated)*, May 2020.

Table 6.18 Demand management step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	1.5	1.6	2.1	2.0	1.5	8.6
AER draft decision	–	–	–	–	–	–
Difference	–1.5	–1.6	–2.1	–2.0	–1.5	–8.6

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 148; AER analysis.
Note: Numbers may not add up to total due to rounding.

We have not received any submissions relating to this step change.

Lower Mornington Peninsula demand management program

United Energy proposed an incremental amount of $5.9 million ($2020–21) to enhance and continue its existing Lower Mornington Peninsula demand management program.[159] United Energy completed a Regulatory Investments Test for Distribution (RIT-D) relating to this program in 2016 and implemented a four-year demand management program to defer capex up until 2022. United Energy forecast demand to flatten over the next few years, creating an opportunity to continue the demand management program and further defer the capital expenditure to the 2026–2030 regulatory control period.[160]

United Energy's 2019 base opex includes the cost of the Lower Mornington Peninsula demand management program. United Energy considered a step change for incremental cost is required because:[161]

- more demand management is required to meet the growth in maximum demand
- the current demand management contract costs understate the actual cost of demand management, and the current supplier (GreenSync) has had to absorb the cost overrun.

Our starting position is that is step changes should not double count costs included in other elements of the opex forecast. As explained in the Expenditure Assessment Guideline, the costs of increased volume or scale should be compensated for through the rate of change and it should not become a step change.[162] Further, in this instance we consider the proposed incremental amount is overstated because the calculations of demand management requirement was based on United Energy’s energy demand

159 United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model (updated)*, May 2020.

160 United Energy, *2021–26 Regulatory proposal – Supporting document 9.02 – Lower Mornington Peninsula demand management*, January 2020, p. 5.

161 United Energy, *2021–26 Regulatory proposal – Supporting document 9.02 – Lower Mornington Peninsula demand management,* January 2020, p. 5.

162 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

forecast submitted at the time of the proposal, which we have adjusted to lower levels (see Attachment 5 of this draft decision). Lower forecast demand is likely to result in lower demand management requirements and lower associated costs, all else being constant.

Consequently, we have not included the proposed incremental costs of the Lower Mornington Peninsula demand management program in our alternative estimate of total opex.

HV feeders demand management program

United Energy proposed $1.0 million ($2020–21) of demand management to address the risk of overload for nine high voltage (HV) feeders.[163] United Energy submitted that the proposed amount would defer augmentation capex, within the 2021–26 regulatory control period, relating to the nominated feeders.

In our review, we have updated United Energy's demand management model to take into account our updated demand forecasts. This has reduced the number of HV feeders at risk of overload over the 2021–26 period from nine to three. Our capex forecast already includes the augmentation expenditure for these feeders in the 2021–26 period.

Consequently, we have not included the proposed demand management amount in our alternative estimate of total forecast opex.

Cranbourne Terminal Station (CBTS) demand management program

United Energy proposed $1.6 million ($2020–21) of demand management at the distribution network level to defer augmentation of the CBTS transmission connection assets (e.g. construction of a fourth transformer).[164] CBTS is a transmission connection asset owned and operated by AusNet Services transmission, which services AusNet Services and United Energy's distribution networks.[165]

United Energy submitted that under its distribution licence, it has the responsibility to plan and direct augmentation of transmission connection facilities (like CBTS). As a result, it has identified a potential demand management option at the distribution network level to defer augmentation of the CBTS transmission connection assets.

The costs of any augmentation at CBTS would be borne by AusNet Services transmission. In this case, United Energy would incur the demand management costs (as the demand management scheme would be undertaken at the distribution level),

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163 United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model (updated)* (demand management sheet), May 2020.

164 United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model (updated)* (demand management sheet), May 2020.

165 United Energy, *2021–26 Regulatory proposal – Supporting document 9.04 – Cranbourne terminal station*, January 2020, p. 5.

while AusNet Services transmission would benefit in the form of deferred investment. We note AusNet Services distribution has proposed to absorb costs relating to demand management associated with the CBTS.

As a matter of principle, we agree that networks can recover the costs associated with investment in transmission-distribution connection assets and this is consistent with statements in AEMC determinations highlighted by United Energy.[166] However, there is no capex/opex trade-off for United Energy, as any augmentation costs will be borne by the owner of the asset, AusNet Services transmission.

In instances where one network is undertaking demand management to defer network investment on another network, we consider it is appropriate for the opex and capex costs of such projects to be assessed as part of the revenue determination of the party responsible for the augmentation (in this instance AusNet Services transmission). To the extent these opex costs are incurred by AusNet Services distribution or United Energy, these can be funded by AusNet Services transmission. Further, in this instance, the Regulatory Investments Test for Transmission for upgrading CBTS has only recently commenced and submissions will close in late September 2020.[167]

Accordingly, we have not included the proposed demand management amount in our alternative estimate of total opex.

IT cloud solutions

United Energy proposed a $4.7 million ($2020–21) step change for cloud hosting.[168] We have included this step change in our alternative estimate as we consider the capex/opex trade-off results in forecast expenditure that is likely to be prudent and efficient.

Table 6.19 IT cloud step change estimate ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal and AER draft decision	0.7	0.7	1.0	1.2	1.2	4.7

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 148; AER analysis.

Note: Numbers may not add up to total due to rounding.

166 United Energy, *Information request 36 – Demand Management Opex Step Change*, 19 June 2020, pp. 5–6.

167 See https://aemo.com.au/consultations/current-and-closed-consultations/cranbourne-terminal-station-electricity-supply-rit-t---pscr

168 United Energy, *2021–26 Regulatory Proposal*, January 2020 pp. 144, 148.

The step change involves migrating its core ICT applications and a portion of its non-critical applications to cloud hosting ICT, which is ICT infrastructure that is owned and managed by third party vendors and typically paid for on a subscription basis.[169]

United Energy proposed the $4.7 million ($2020–21) step change as a capex-opex trade-off.[170] This was supported by a NPV options analysis, summarised in Table 6.20. United Energy submits its proposed option (option 2 in Table 6.20) of balanced cloud migration and refresh of remaining on-premise infrastructure will result in the lowest net present value cost[171]. This option provides the longer term benefits of cloud hosting such as easy scalability and adaptability of its ICT infrastructure to changing requirements.[172]

We have engaged expert consultants, EMCa, to assist us with this assessment.

United Energy provided details of its risk-cost assessment of four options considered in its business case, which included a 'do nothing' option, an on-premise infrastructure restructure and a balanced or aggressive cloud migration and refresh of remaining on-premise infrastructure.[173] EMCa advised that the stated benefits of cloud IT hosting is consistent with trends observed within the industry and therefore the proposed strategy of moving progressively to cloud is superior to the option of 'do nothing'.

Table 6.20 United Energy's summary of options for IT cloud step change ($ million, 2020–21)

Option	Description	Capex	Incremental opex	NPV expenditure	Risk
0 - Do nothing	Do not refresh or grow existing on-premise infrastructure. Do not migrate to cloud	0.0	0.0	0.0	222.2
1 - On-premise infrastructure refresh	Do not migrate existing on premise infrastructure to cloud hosting	31.9	0.0	29.2	3.9
2 - Balanced cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 25% of non-core applications across the regulatory control period to cloud hosting; refresh remaining on-premise infrastructure	22.8	4.5	25.0	3.9

169 United Energy, *2021–26 Regulatory proposal – Supporting document 7.10 – Cloud infrastructure*, February 2020, pp. 5–6

170 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 144, 149.

171 United Energy, *2021–26 Regulatory proposal – Supporting document 7.10 – Cloud infrastructure*, February 2020, p. 15.

172 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 149.

173 United Energy, *2021–26 Regulatory proposal – Supporting document 7.10 – Cloud infrastructure*, February 2020, p. 15.

3 - Aggressive cloud migration and refresh remaining on-premise infrastructure	Migrate core ICT applications plus 50% of non-core applications to cloud hosting across the regulatory control period; refresh remaining on-premise infrastructure.	22.4	6.4	26.5	3.9

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 7.10 – Cloud infrastructure,* February 2020, p. 15.

In its business case, United Energy stated that its forecast opex for migrating applications to cloud hosting is based on vendor advice sourced by external advisors.[174] EMCa's assessment found it appropriate to source vendor estimates as a basis for its opex forecast for cloud migration, and found the cost estimates proposed by United Energy as reasonable.[175] In particular, EMCa found the opex step change to cover the cloud hosting fees of $4.5 million ($2020–21) is reasonable.[176] Further, EMCa considered the methodologies for United Energy's estimates for capex and opex savings and opex increases for its preferred option are reasonable are based on reasonable methodologies.[177] United Energy submits that the opex savings from migration to cloud hosting relate to the potential for reduced maintenance for on-premise infrastructure, this opex saving is estimated as a five per cent capex reduction.[178] United Energy indicated that achieving the material opex savings will only occur in a future regulatory control period. EMCa noted that while United Energy did not provide a justification for this amount in its business case or model, this estimated opex savings for the next regulatory control period is reasonable.[179]

While we consider United Energy's IT cloud step change (option 2) is reasonable overall, we note EMCa's advice that the proposed capex for refreshing and growing its remaining on-premise infrastructure has not been adequately justified. United Energy estimated a reduction of $5.9 million in capex afforded by shifting some infrastructure to the cloud, a $1.2 million reduction due to labour savings and a $2.1 million reduction due to contracts savings, for a total saving of $9.1 million ($2020–21).[180] EMCa considered United Energy's estimate as reasonable, but did not include any storage capex cost reductions from its proposed cloud migration activity.[181]

We consider it is appropriate to include the IT cloud step change in our alternative estimate for these businesses as it meets the step change criteria of an efficient

[174] United Energy, *2021–26 Regulatory proposal – Supporting document 7.10 – Cloud infrastructure*, February 2020, p. 14.

[175] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 188.

[176] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 189.

[177] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 189.

[178] United Energy, *Information request 20 – EMCa ICT forecast questions*, June 2020, p. 9.

[179] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 189.

[180] United Energy, *2021–26 Regulatory proposal – Supporting document 7.15 – Cloud infrastructure cost*, January 2020.

[181] EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 189.

capex-opex trade-off and is the lowest cost option to meet their ICT infrastructure needs. This is consistent with our standard step change assessment approach.

Solar enablement

United Energy proposed a step change totalling $4.2 million ($2020–21) to remove voltage constraints on its network and enable more customers to export excess solar back into the network.[182] The proposed step change is part of United Energy's Solar enablement program to enable customers to connect to solar, and to remove solar constraints where it is economical to do so.[183] United Energy considered this will help remove constraints caused by the step up in solar installations resulting from the Victorian Government's Solar Homes subsidy program.[184] United Energy also proposed $42.4 million ($2020–21)[185] of capex related to the Solar enablement program.

Table 6.21 Solar enablement step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy	0.9	0.8	0.8	0.8	0.8	4.2
AER draft decision	–	–	–	–	–	–
Difference	–0.9	–0.8	–0.8	–0.8	–0.8	–4.2

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 148; AER analysis.

Note: Numbers may not add up to total due to rounding.

United Energy's proposed Solar enablement step change comprises the following:

- $3.2 million ($2020–21) to manually tap down distribution transformers to remove voltage constraints.[186] United Energy proposed to 'tap down' 2111 transformers over the 2021–2026 regulatory control period,[187] and the cost of tapping is based on using the average cost per site tapped in 2018.[188]
- $0.7 million ($2020–21) to undertake a monitoring and compliance regime to ensure appropriate (compliant) inverter settings have been applied.[189]
  United Energy stated that if non-compliant settings are applied, voltage rises will be

[182] This amount includes escalation of real prices, see United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model*,, January 2020; United Energy, *2021–26 Regulatory Proposal* p.148.

[183] United Energy, *2021–26 Regulatory proposal*, January 2020, p. 148.

[184] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 92.

[185] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 94.

[186] United Energy, *2021–26 Regulatory proposal – Supporting document 6.06 – Solar enablement*, January 2020, p.25; AER analysis.

[187] United Energy, *2021–26 Regulatory proposal – Supporting document 6.02 – Enabling solar model*, January 2020

[188] United Energy, *2021–26 Regulatory proposal – Supporting document 6.06 – Solar enablement*, January 2020, p.32.

[189] United Energy, *2021–26 Regulatory proposal – Supporting document 6.06 – Solar enablement*, January 2020, p. 25; AER analysis.

significantly higher than forecast and customers will experience more tripping.[190] United Energy's forecast monitoring and compliance cost assumed a rate of five per cent non-compliant inverter settings amongst its current solar customers. Further, United Energy noted that non-compliance with new inverter settings is expected to be material, even with the mandated inverter settings.[191]

Our standard approach is to not provide a step change to manage activities in a changed operating environment, as opex increases in line with output growth forecasts would typically provide adequate compensation to a prudent operator for operating and maintaining a network. However we had previously acknowledged where output growth does not fully account for growing distributed energy resources, it may be appropriate to allow a step change for distributed energy resources management.[192] As United Energy is seeking to manage its mandated inverter settings due to the increased number of forecast solar PV connections to its network, and in the short term, the output growth forecast may not fully account for distributed energy resources, we consider there may be a case for United Energy's solar enablement as a possible step change.

However, for us to accept the proposed step change, we have to be satisfied that United Energy's proposed expenditure for this step change is prudent and efficient. We have engaged expert consultants, EMCa, to assist us in this assessment.

While we consider there is a legitimate driver for a step change to cover higher opex as a result of distributed energy resources management related activities, we have not included the step change in our alternative estimate for the reasons below.

We consider United Energy's proposal to undertake tapping activities and the volume proposed as prudent and reasonable. EMCa advised tapping activities is a relatively inexpensive means to improve the hosting capacity of a low voltage feeder or section of a feeder, before applying network solutions.[193] Further, EMCa considered United Energy's modelling of voltage rises as a reasonable approach and as such the proposed number of tap changes is likely to be a reasonable estimate.[194]

However, EMCa then benchmarked tapping costs across the Victorian distributors and observed[195] United Energy's unit cost of $1535 ($2020–21)[196] is significantly higher than AusNet Services $865 ($2020–21) per unit.[197] EMCa were not aware of any

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190 United Energy, *2021–26 Regulatory proposal – Supporting document 6.06 – Solar enablement*, January 2020, p. 34.

191 United Energy, *2021–26 Regulatory proposal – Supporting document 6.06 – Solar enablement*, January 2020, p. 34.

192 AER, *Draft decision, SA Power Networks distribution determination 2020–2025, Attachment 6 Operating expenditure*, October 2019, pp. 48–50.

193 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 152.

194 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 152.

195 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 152.

196 United Energy, *2021–26 Regulatory proposal – Supporting document 6.02 – Enabling solar model*, January 2020; AER analysis.

197 AusNet Services, *Information request 49, Q–3,* July 10, p. 6. .

reasons which explain the significantly higher unit cost.[198] EMCa concluded an efficient unit cost for tapping would be under $1000.[199]

We agreed with the concerns raised by EMCa in relation to the unit costs and adjusted United Energy's estimate of tapping costs based on its findings. This reduced the costs of the proposed step change from $3.2 million to $2.1 million or $1.8 million depending on whether a unit cost of $865 or $1000 is used. As a result of this, we consider this cost to be immaterial and should be managed within United Energy's total forecast opex.

While we consider correction of non-compliance inverter settings will likely help manage voltage constraints, we are not satisfied that United Energy's monitoring and compliance program is efficient. EMCa considered addressing non-compliance of inverter settings is likely to be a relatively cost-effective means of helping to limit the effects of PV export voltage rise.[200] However, based on information United Energy provided, EMCa was not convinced United Energy had explored cost-effective options to proactively ensure correct inverter settings were installed and address non-compliance, and had justified that a separate program to its existing business-as-usual Power Quality program was required.[201] Accordingly, we do not consider this cost has been sufficiently justified and have not included this cost in our alternative estimate.

Five minute settlement

United Energy proposed a step change of $3.9 million ($2020–21)[202] in response to the five minute settlement rule by the AEMC published on 28 November 2017[203] to change the settlement period for the electricity wholesale market from 30 minutes to five minutes to align with the operational dispatch of electricity.

Our draft decision is to substitute with an alternative estimate of $3.7 million ($2020–21).

Table 6.22 Five minute settlement step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	0.6	0.6	0.8	0.9	1.1	3.9
AER draft decision	0.5	0.6	0.7	0.8	1.0	3.7
Difference	0.0	0.0	–0.1	–0.1	–0.1	–0.3

198 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p.152.

199 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p.152.

200 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 153.

201 EMCa, *United Energy Proposal 2021–26: Review of Aspects of Proposed Expenditure*, August 2020, p. 153.

202 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144.

203 AEMC, *Five Minute Settlement, final determination*, 28 November 2017.

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

On 9 July 2020, the AEMC made rules to delay the commencement of the five minute settlement rule by three months, so they commence on 1 October 2021. A three month delay balances the capacity constraints placed on the industry by COVID–19 against the additional costs and deferred benefits that are caused by a delay to the commencement of the respective rules.[204] This was a concern raised by the ECA who questioned the initial costs proposed due to the delay.[205] The VCO also noted the difference in proposed costs amongst the Victorian distributors and we have taken this into account during our assessment.[206]

We have reviewed the AEMC rules on the delay to the commencement of five minute settlement and consider it should not have a material impact on United Energy's step change as the delay only relates to meter types 1-3.[207] United Energy's proposal only relates to Victorian type 5 AMI meters, which still must be configured to record five minute data from 1 December 2020 as set out in the AEMC five minute settlement rule made on 28 November 2017.[208] We are satisfied that the AEMC rules are a new regulatory obligation and the efficient costs to meet these obligations should be included as a step change.

United Energy's opex step change proposal is comprised of two key categories:

- Increasing United Energy's wide area network (WAN) and data processing capacity to transport and process increased volume of meter data – $0.9 million ($2020–21).
- Manage an increase in the volume of manual validations of meter data exceptions – $3.1 million ($2020–21).

We view these proposed costs as reasonable but have made two adjustments in developing our alternative estimate that aligns with our rate of change decision:

- The costs associated with manual data exceptions are dependent on meter volumes and therefore, the assumptions for the expected growth in meter connections over the 2021–26 regulatory control period are important. Table 6.23 shows the difference between the meter growth proposed by United Energy and our alternative estimate.

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204 AEMC, *Delayed Implementation of five minute and Global settlement, Rule determination,* 9 July 2020, p. i.

205 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026, Attachment 1: A review of Victorian Distribution Networks*, p. 28.

206 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p. 66.

207 AEMC, *Five Minute Settlement, final determination*, 28 November 2017, p. v; NER, cl. 11.103.1.

208 AEMC, *Five Minute Settlement, final determination*, 28 November 2017, p. v.

Table 6.23 United Energy meter growth forecast proposed and our draft decision

	2021–22	2022–23	2023–24	2024–25	2025–26
United Energy proposed growth in total meters	3.1%	1.6%	1.4%	1.3%	1.3%
AER alternative estimate	1.2%	1.4%	1.3%	1.3%	1.2%

Source: United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model,* January 2020; AER analysis.

- Our alternative estimate is based on the revised customer growth forecasts that take into account COVID–19 and are consistent with our rate of change decision on output growth.
- United Energy include a real price escalation that factors in expected labour cost increases over the 2021–26 regulatory control period. We have adjusted these assumptions to align with our rate of change decision on price growth.

These two adjustments result in an alternative estimate of $3.7 million ($2020–21).

ESV levy

United Energy proposed a step change of $2.5 million ($2020–21) in response to the forecast incremental increase in the Energy Safe Victoria (ESV) levy over the 2021–26 regulatory control period.[209] In United Energy's proposal, the costs incurred in 2019–20 was $2.4[210] million ($2020–21) and the ESV levy proposed is approximately $2.9 million ($2020–21) per annum, an increase of $0.5 million ($2020–21).

Our draft decision is not to include the proposed step change for the reasons outlined below.

Table 6.24 ESV levy step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	0.4	0.5	0.5	0.5	0.5	2.5
AER draft decision	–	–	–	–	–	–
Difference	–0.4	–0.5	–0.5	–0.5	–0.5	–2.5

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

209 United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model,* January 2020.

210 United Energy, *2021–26 Regulatory proposal – Supporting document 9.01 – Step change model,* January 2020.

The ESV levy is used to fund the ESV activities related to regulating the Victorian distributors. These ESV costs are spread across the network operators based on the proportion of customers on each distributor's network. We have checked with the ESV and its advice on the ESV levy cost changes is consistent with United Energy's proposal.

Base opex already reflects the cost of meeting existing regulatory obligations, and maintaining the reliability, safety and quality of supply of standard control services. United Energy's base opex includes ESV levy costs as it is an existing regulatory obligation. In the absence of exceptional circumstances, fluctuations in the ESV levy should be managed within base opex and the rate of change.

As outlined in the Expenditure Assessment Guideline, actual past expenditure, if efficient, should provide a good indicator of required funding in the future[211]. Opex tends to be stable or recurrent both on a year by year basis and when comparing opex across regulatory control periods. If a service provider is operating efficiently, there should be few reasons why its forecast opex in a regulatory control period should be materially different to its past spending in the previous regulatory control period.

We acknowledge that some types of projects and programs of expenditure a service provider undertakes will differ between years and between regulatory control periods. However, we do not consider variation in the expenditure projects, programs or levies is a reason to increase the revenue it can recover from electricity network consumers. What matters is whether the cost of these programs is likely to affect the total efficient opex a prudent service provider would require to meet all existing regulatory obligations, meet or manage expected demand, and maintain the reliability, safety and quality of supply.

Movements in expenditure related to certain programs, projects or levies can often be funded as the cost of other programs and projects in the base year decline – particularly for costs that are immaterial relative to total opex.

In addition the rate of change formula escalates final year opex by the forecast change in prices, output and productivity. This forecast over the regulatory control period serves to capture fluctuating input prices, higher expenditure to deliver greater output and productivity improvements over the period. It is expected that changes to specific costs can be managed within the existing base and the rate of change forecast.

Our assessment has considered the submission from the CCP17 who noted the different approaches the Victorian distributors have proposed to recover ESV levies which range from base adjustments, category specific forecasts and step changes. The CCP17 also saw merit in ensuring a uniform approach to treating these costs across the five businesses.[212]

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211 AER, *Expenditure assessment forecast guideline*, November 2013, p. 22.

212 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p 54.

Accordingly, we consider the ESV levy step change costs proposed by United Energy can be managed within its existing base opex and the forecast rate of change provided. The incremental cost of the ESV levy is immaterial relative to United Energy's total opex (representing 0.3 per cent of proposed opex).

Insurance premiums

United Energy proposed a $2.2 million ($2020–21) step change related to the increasing costs of general liability insurance premiums. United Energy explain in its proposal that the rising number of bushfire events in a short time period has resulted in significant insurer losses and insurer exits from the market.[213] As a result of market exits, reductions in offered capacity and hardening of insurance criteria, there has been a material increase in bushfire insurance premiums. Premiums for the year ending 30 September 2020 (2019–20) are 31 per cent higher compared to 2018–19 for the same level of cover.[214]

Our draft decision is not to include the proposed step change in our alternative estimate for the reasons outlined below.

Table 6.25 Insurance premiums step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	0.4	0.4	0.4	0.4	0.4	2.2
AER draft decision	–	–	–	–	–	–
Difference	–0.4	–0.4	–0.4	–0.4	–0.4	–2.2

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

The $2.2 million ($2020–21) proposed is calculated based on the incremental increase in actual premiums between the 2019 base year and 2019–20.[215] Whilst United Energy expect costs will continue to grow over the 2021–26 regulatory control period, these have not been proposed.[216] This is in contrast to the similar step change for increasing insurance premiums proposed by Jemena, where Jemena forecasted significant premium increases over the 2021–26 regulatory control period.[217]

We have assessed the insurance premium step change and are not satisfied that it is a step change in United Energy's efficient opex costs, particularly as it is not clear that

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213 United Energy, *2021–26 Regulatory Proposal*, January 2020 pp. 144, 145–146.

214 United Energy, *2021–26 Regulatory Proposal*, January 2020 pp. 145–146.

215 United Energy, *2021–26 Regulatory Proposal*, January 2020 p. 144; United Energy, *2021–26 Regulatory Proposal – Supporting document 9.01 – Step changes,* January 2020

216 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 145–146.

217 Jemena, *2021–26 Regulatory Proposal – Attachment 06-05 – Operating expenditure step changes, February 2020*, p. 5.

the increasing costs are not already captured through the rate of change, specifically non-labour price growth. Our assessment considered similar factors outlined in our recent final decision for SA Power Networks.[218] A summary of these include:

- The proposed insurance premium increases are not related to a new regulatory obligation or a capex / opex substitution, the most common circumstances for which we consider allowing a step change.
- Our trend forecast includes non-labour price growth and this covers any potential increases in costs like insurance premiums.
- We expect some non-labour components in opex will increase by more than CPI and some less than CPI. To the extent that insurance premiums rise by more than CPI, we expect this will to an extent be offset by other non-labour costs rising by less than CPI.
- CPI includes household insurance premiums which cover bushfires. While there are differences between household and utility insurance premium increases, there are similar drivers impacting both and their future growth.

A key factor for our decision not to include this step change in our alternative estimate is the relatively low materiality of the costs proposed (representing 0.3 per cent of total opex). We would expect at this magnitude United Energy should be able to manage such proposed costs within both the trend forecast and reflecting the likely offsetting impact of decreases in cost categories over the 2021–26 regulatory control period.

The CCP17 noted in its submission that it accepted insurance premiums will rise significantly, but considered the issue is primarily about materiality given that insurance is an ongoing cost for businesses. It noted that these increases for Jemena are perhaps more recent than for Powercor and United Energy who possibly had a significant increase in premiums as result of the last round of bushfires and the subsequent Royal Commission.[219] Whilst this could be a contributing factor, we believe the large variance is also attributed to the different forecasting approaches adopted by United Energy, Powercor and Jemena described above.

Financial year RIN

United Energy proposed a step change of $1.8 million ($2020–21) for an additional set of RINs they stated they would be required to report each year of the next regulatory control period.[220]

Our draft decision is not to include the proposed step change for the reasons outlined below.

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[218] AER, *Final decision, SA Power Networks distribution determination 2020–25, Attachment 6 Operating expenditure,* June 2020, pp 26–29

[219] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 2 June 2020, p. 54.

[220] United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 144, 147.

Table 6.26 Financial year RIN step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
United Energy's proposal	0.4	0.4	0.4	0.4	0.4	1.8
AER draft decision	–	–	–	–	–	–
Difference	–0.4	–0.4	–0.4	–0.4	–0.4	–1.8

Source: United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 144; AER analysis.

Note: Numbers may not add up to total due to rounding.

United Energy noted in its initial proposal that it is currently required to submit a set of RIN responses on a calendar year basis. As a result of the change in timing of the Victorian electricity network regulatory control periods from calendar to financial years, United Energy proposed it will be required to submit a second set of RIN responses each year to report on a financial year basis.[221]

The change in timing of the Victorian electricity network regulatory control periods has resulted in adjustments to the reporting requirements of Victorian distribution businesses. In particular, businesses are now obliged to report the following:

- Economic benchmarking (EB), category analysis (CA) and annual (A) RINs for the 2020 calendar year
- EB, CA and A RINs for 12 months between July 1 2020 and June 30 2021 and
- EB, CA and A RINs for the 2021–22 financial year and each financial year going forward.

The change to financial year reporting from 2021–22 replaces the existing obligation to report RINs on a calendar year basis and represents no additional regulatory obligation for United Energy. However, the requirement to report an additional set of RINs for the 2020–21 financial year as part of the transition from calendar to financial year reporting is expected to result in some additional costs.

We consider the additional costs to comply with this incremental change are relatively immaterial. If we were to include step changes for increases in immaterial costs in our alternative estimate, then arguably we should also include negative step changes for decreases in immaterial costs. In this regard, we note that over the next regulatory control period a possible negative step change could arise due to the relaxing of some obligations required by ESV in their electric line clearance regulations, which may lead to immaterial reductions in costs.[222] United Energy has not proposed this as a negative step change. We consider step changes are not meant to be bottom up assessments

[221] United Energy, *2021–26 Regulatory Proposal*, January 2020, p. 147.

[222] Deloitte, *Regulatory Impact Statement: Electricity Safety (Electric Line Clearance - ELC) Regulations 2020*, see costs under Option 2, September 2019, p. 8.

of all cost categories, and that immaterial increases or decreases should be managed by businesses.

The emphasis outlined above is consistent with the CCP17's submission which noted this step change is related to an ongoing obligation and did not view the costs were material enough to warrant a step change.[223] The VCO also questioned the proposed costs from some distributors as AusNet Services appears to be absorbing the costs.[224]

6.4.6 Category specific forecasts

We have included two expenditure items, debt raising costs and GSL payments, in our alternative estimate of total opex which we did not forecast using the base-step-trend approach.

Debt raising costs

We have included debt raising costs of $5.9 million ($2020–21) in our alternative estimate. This is $0.6 million ($2020–21) less than the $6.5 million forecast ($2020–21) proposed by United Energy.[225]

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 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.

GSL payments

We have included GSL payments of $3.3 million ($2020–21) in our alternative estimate. This is $1.0 million ($2020–21) less than the $4.3 million forecast ($2020–21) proposed by United Energy.[226]

We have forecast GSL payments as the average of GSL payments made by United Energy between 2015 and 2019 whereas United Energy's calculation took the average of the period between 2014 and 2020 (in which 2019 and 2020 was an estimate based on 2018).

The incentives provided by our forecasting approach are consistent with adopting a single year revealed cost approach and applying the EBSS. We have adopted the

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223 CCP17, *Advice to the AER on the Victorian Electricity Distributors’ Regulatory Proposals for the Regulatory Determination 2021–26,* p. 54.

224 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p. 67.

225 United Energy, *2021–26 Regulatory Proposal*, January 2020 p. 140.

226 United Energy, *2021–26 Regulatory proposal – Supporting document 10.06 – Opex model*, January 2020.

historical averaging approach to maintain consistency with how GSL payments have been forecast for previous regulatory control periods.

United Energy did not include a category specific forecast for GSL payments. Instead, it adjusted its base opex to reflect a historic average of its GSL payments.[227] Consequently it did not include an explicit forecast for GSL payments in its total opex forecast. It stated that this approach is consistent with the approach we adopted in previous regulatory decisions.[228] However, for the 2016–20 regulatory control period we included GSL payments as a category specific forecast.[229]

United Energy proposed that GSL payments be excluded from the EBSS for the 2021–26 regulatory control period.[230] In order to exclude GSL payments from the EBSS we require an explicit forecast.

We note the Essential Services Commission of Victoria is currently undertaking a review of the consumer protection framework in the Electricity Distribution Code, including the GSL scheme.[231] A draft decision was published on 7 May 2020[232] which sets out proposed changes to the GSL scheme. Consultation on the draft decision closed 2 July 2020. As the review has not been completed we have calculated GSL payments based on the current GSL scheme and not taken into account the proposed changes. Provided the Essential Services Commission's review is completed by early next year, we will update the GSL payment forecasts in our final decision to take into account the impact of the GSL scheme changes.

6.4.7 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'.[233]

We attach different weight to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[234]

> 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

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227 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 151–152.

228 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 151–152.

229 AER, *Final decision, United Energy distribution determination 2016–2020, Attachment 7 Operating expenditure*, May 2016, pp. 80–81.

230 United Energy, *2021–26 Regulatory Proposal*, January 2020, pp. 173.

231 https://www.esc.vic.gov.au/electricity-and-gas/codes-guidelines-and-policies/electricity-distribution-code/electricity-distribution-code-review-2019.

232 Essential Services Commission, *Electricity Distribution Code review – customer service standards draft decision,* 7 May 2020

233 NER, cl. 6.5.6(e).

234 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, Final Rule Determination, 29 November 2012, p. 115.

AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.27 summarises how we have taken the opex factors into account in making our draft decision.

Table 6.27 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 operating expenditure that would be incurred by an efficient distribution network service provider over the 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 operating expenditure that would be incurred 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 a hypothetically 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 economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of United Energy's 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 United Energy's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure 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 factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[235] Based on the information provided by United Energy in its proposal and CCP17's advice, we consider United Energy consulted with consumers in developing its proposal. We have examined the issues raised by consumers in developing our alternative estimate of opex.
The relative prices of capital and operating inputs	We have considered capex/opex trade-offs in considering United Energy's proposed step changes. For instance we considered whether a step change for IT cloud is an efficient capex/opex trade-off. We considered the relative capex and opex costs for proposed solutions in considering this step change. We have 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

235 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, Final Rule Determination, 29 November 2012, pp. 101, 115

Opex factor	Consideration
	efficiency of networks in the use of both capital and operating inputs with respect to the 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 United Energy's 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 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.
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 United Energy's 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 United Energy's 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.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. 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 their 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 considered this factor in assessing United Energy’s proposed demand management step change. We reviewed whether the proposed non-network costs were prudent and efficient based on the information provided by United Energy, including comparisons between network and non-network options.
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. We note part of the demand management step change proposed by United Energy related to an extension of the demand management solution identified in the Lower Mornington Peninsula RIT-D final project assessment report. Our assessment considered whether a step change was warranted to provide for the incremental cost of extending the demand management arrangements identified as part of the preferred option.
Any other factor the AER considers relevant and which the AER has notified the Distribution	We did not identify and notify United Energy of any other opex factor.

Opex factor	Consideration
Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	

Source: AER analysis.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCP17	Consumer Challenge Panel, sub-panel 17
DMIAM	demand management innovation allowance mechanism
Distributor/DNSP	distribution network service provider
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ESC	Essential Services Commission
ESV	Energy Safe Victoria
F&A	Framework and Appraoch
GSL	Guaranteed Service Level
MPFP	multilateral total factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
OEF	operating environment factors
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
REFCL	Rapid Earth Fault Current Limiter
repex	replacement expenditure
RIN	regulatory information notice