DRAFT DECISION

Jemena
Distribution Determination
2021 to 2026

Attachment 6
Operating expenditure

September 2020

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Jemena 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

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6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other noncapital expenses incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

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

6.1 Draft decision

We do not accept Jemena's opex forecast of $576.6 million ($2020–21)[1] for the 2021–26 regulatory control period because we are not satisfied that it reasonably reflects the opex criteria.[2]

Our alternative estimate of total opex is $499.8 million ($2020–21). This is $76.8 million ($2020–21), or 13.3 per cent, lower than Jemena's forecast. We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria.

Table 6.1 sets out Jemena's proposal, including updates it submitted, our alternative estimate for the draft decision and key differences. The updates it submitted include a proposed reduction to its proposal of $20.2 million ($2020–21) to hand back the results of its 2019 transformation program more quickly.

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

	Jemena's Proposal	Updated proposal	AER draft decision	Difference
Base (reported opex in 2018)	427.8	427.8	422.5	-5.3
Efficiency adjustment	0.0	0.0	-44.9	-44.9
Base year adjustments	62.1	0.0	0.0	-62.1
Final year increment	12.5	83.7	79.2	66.7
Trend: Output growth	23.2	19.6	11.6	-11.6
Trend: Real price growth	10.7	9.2	0.8	-9.8
Trend: Productivity growth	-7.4	-7.5	-5.8	1.6
Step changes	42.4	21.3	32.4	-10.0

1 Including debt raising costs. Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. viii.

2 NER, cl. 6.5.6(d).

	Jemena's Proposal	Updated proposal	AER draft decision	Difference
Category specific forecasts	1.0	0.9	0.1	-1.0
Total opex (excluding debt raising costs)	572.2	554.9	495.8	-76.4
Debt raising costs	4.4	4.3	4.0	-0.4
Total opex (including debt raising costs)	576.6	559.3	499.8	-76.8
Percentage difference to proposal				-13.3%

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020; AER analysis.

Notes: Numbers may not add up to totals due to rounding.

The difference is between Jemena's proposal and our draft.

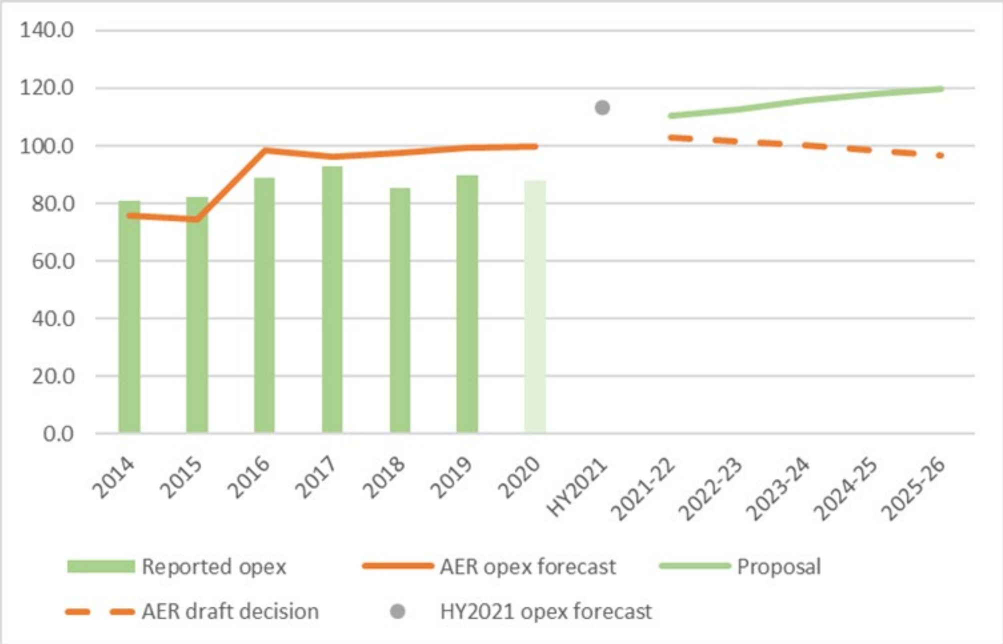
Jemena updated its proposal to incorporate its proposed base adjustment for the expensing of corporate overheads into the calculation of its final year increment (as this will occur from 1 January 2021). It also added a negative step change to hand back the results of its 2019 transformation program more quickly, and withdrew its proposed step change in relation to transitional return on debt alignment costs. See section 6.2. Category specific forecasts reflect the net change.

Figure 6.1 shows Jemena's opex forecast, its actual opex, our previous regulatory decisions and our alternative estimate that is the basis for our draft decision. Jemena's opex forecast was 29.6 per cent higher in the 2021–26 regulatory control period compared to its actual and estimated opex in the 2016–20 regulatory control period. [3] Our alternative estimate for the draft decision is 12.3 per cent higher than Jemena's actual and estimated opex in the current regulatory control period.[4]

3 On a like for like basis, after removing the adjustment for the expensing of corporate overheads, which does not begin until 1 January 2021, this is 15.6 per cent.

4 On a like for like basis, after removing the adjustment for the expensing of corporate overheads our draft decision is 1 per cent lower than the actual and estimated opex in the 2016–20 regulatory control period.

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



Source: Jemena, IR001 – RIN 5 - *Workbook 1 - Regulatory determination – Public – 10 March 20;* Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020; AER, *Draft Decision, Jemena distribution determination 2021–26, Opex model,* September 2020; AER, *Draft Decision, Jemena distribution determination 2021–26, EBSS model,* September 2020; AER analysis.

Note: We have not included in the 2020 estimate the expensing of corporate overheads under Jemena's new CAM, as this does not occur until 1 January 2021.

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

- From our assessment of revealed costs, a range of benchmarking techniques and our analysis of its category costs we consider that Jemena's opex has been relatively inefficient over time and in the 2018 base year. Given this, we have made an efficiency adjustment to Jemena's base year opex. While we consider base year opex should be 15 per cent lower, we also consider that it will take time and involve costs for management to implement the required programs over the next regulatory control period to transition to efficient costs. Given this, we have used a glide path to reduce opex by 3 per cent per annum, with a reduction of 15 per cent in the last year of the five year regulatory control period. We consider that this provides for the prudent, practicably achievable, efficient costs that will enable Jemena to maintain the quality, reliability, security and safety of services. This means our alternative estimate is $44.9 million ($2020–21) lower than Jemena's initial proposal. Taking into account Jemena's update to reduce its opex forecast by $20.2 million (and hand back the results of its 2019 transformation program more quickly), means our efficiency adjustment is $24.7 million ($2020–21) more than Jemena included in its updated proposal.
- Our forecast rate of change by which we trend opex forward over the next five years is on average 0.6 per cent each year. This is lower than Jemena's proposed

1.4 per cent per year on average. This is primarily driven by our lower price and output growth forecasts, which in large part reflect the impacts of COVID–19 on wage price growth and reliance on the Australian Energy Market Operator's (AEMO's) maximum demand forecasts. This lowers our alterative estimate compared to Jemena's proposal by $19.9 million ($2020–21).

- 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 reconsider updating the rate of change forecast using our standard approach provided the necessary forecasts are available.
- We generally only include step changes where we are satisfied there are efficient costs associated with new regulatory obligations or capitals expenditure (capex)/opex trade-offs and these costs are not already captured in base opex or through our trend forecast. We consider Jemena's proposed step up in opex required for bushfire liability insurance over the 2021–26 regulatory control period is prudent and efficient and have included an increase in costs for this of $28.2 million ($2020–21) in our alternative estimate. However, we have not included some step changes proposed by Jemena as we did not consider there was sufficient evidence to demonstrate the proposed costs were efficient (the future grid program and Environment Protection Authority (EPA) regulation changes) or are driven by material new obligations (financial year regulatory information notice (RIN) step change). This lowers our alternative estimate compared to Jemena's proposal by $10.0 million ($2020–21).

In making our draft decision we have taken into account Jemena's customer engagement, including its People's Panel, and the feedback we have received from other stakeholders.

Jemena's customer consultation for opex appears to have been relatively high level and focused on total opex. Noting the importance of affordability to customers, and maintaining safe and reliable services, Jemena stated that it is committed to delivering initiatives aimed at reducing costs now and into the future. Jemena has undertaken a transformation program to reduce costs and has proposed in to pass savings onto consumers in the form of lower opex. However, and as noted above, we consider that further efficiency gains are possible with additional savings to customers in the next regulatory control period. In addition, while over 90 per cent of its People Panel were comfortable that Jemena's draft plan (including the opex proposal) sufficiently considers their long-term interests, there was scope for Jemena to further engage with its customers on specific components of its proposal. We received feedback from a number of stakeholders who had concerns with specific aspects of Jemena's proposal including the efficiency of Jemena's base year opex, the trend forecasts in light of COVID–19 impacts and the quantum of proposed step changes.

6.2 Jemena's proposal

Jemena used a 'base–step–trend' approach to forecasting 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, Jemena:

- Used actual opex in 2018 of $85.6 million ($2020–21) as the base to forecast its costs for the next regulatory control period.[5]
- Adjusted its base year opex to recognise the change in its Cost Allocation Methodology (CAM) from 1 January 2021 to treat all corporate overheads as opex. This increased its base opex by $12.4 million ($2020–21) per annum or $62.1 million ($2020–21) over the next regulatory control period.[6]
- Applied the approach in the Expenditure Forecast Assessment Guideline for electricity distribution (the Expenditure Assessment Guideline) to calculate the final year increment to derive the starting point for its opex forecast. This increased its base opex forecast by $2.5 million per annum ($2020–21) or $12.5 million ($2020–21) over the next regulatory control period.[7]
- Applied its forecast rate of change to its opex forecast, consistent with the Expenditure Assessment Guideline.[8] This increased its opex forecast by $26.5 million ($2020–21), including real price growth of $10.7 million ($2020–21), output growth of $23.2 million ($2020–21) and productivity growth of $7.4 million ($2020–21).[9]
- Proposed seven step changes related to bushfire insurance premium increases, new Rapid Earth Fault Current Limiter (REFCL) testing and maintenance obligations, a Future Grid program, transitional return on debt alignment costs, new EPA regulations, new cyber-security obligations and additional RIN reporting obligations. This increased its opex forecast by $42.4 million ($2020–21).[10]
- To develop its opex category specific forecast, Jemena proposed the removal of Guaranteed Service Level (GSL) payments and Energy Safe Victoria (ESV) distributor levies from base opex, which decreased opex by $6.7 million ($2020–

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5 This excludes movements in provisions and demand management innovation allowance (DMIA) payments. Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26*; 25 February 2020; AER analysis.

6 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 15; Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020.

7 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

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

9 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020; AER analysis.

10 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, pp. 23-24.

21) over the 2021–26 regulatory control period.[11] This decrease is offset by category specific forecasts for the ESV Levy of $6.9 million ($2020–21) and GSL payments of $0.8 ($2020–21).[12] This results in a net increase of $1.0 million ($2020–21) in category specific forecast.[13]

Excluding debt raising costs, Jemena's total opex forecast is $572.2 million ($2020–21) for the 2021–26 regulatory control period (see Table 6.2). Jemena is forecasting opex will be 29.6[14] per cent higher in the 2021–26 regulatory control period compared to its actual and estimated opex in the 2016–20 regulatory control period. Opex represents 44.8 per cent of Jemena's total revenue in its proposal.[15]

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

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Total opex including category specific forecasts	109.7	111.9	114.8	116.8	118.9	572.2
Debt raising costs	0.8	0.9	0.9	0.9	0.9	4.4
Total opex	110.5	112.8	115.7	117.7	119.8	576.6

Source: Jemena, 2021–26 *Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, p. 29; Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020.

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

Figure 6.2 shows the different components in Jemena's opex proposal.

11 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

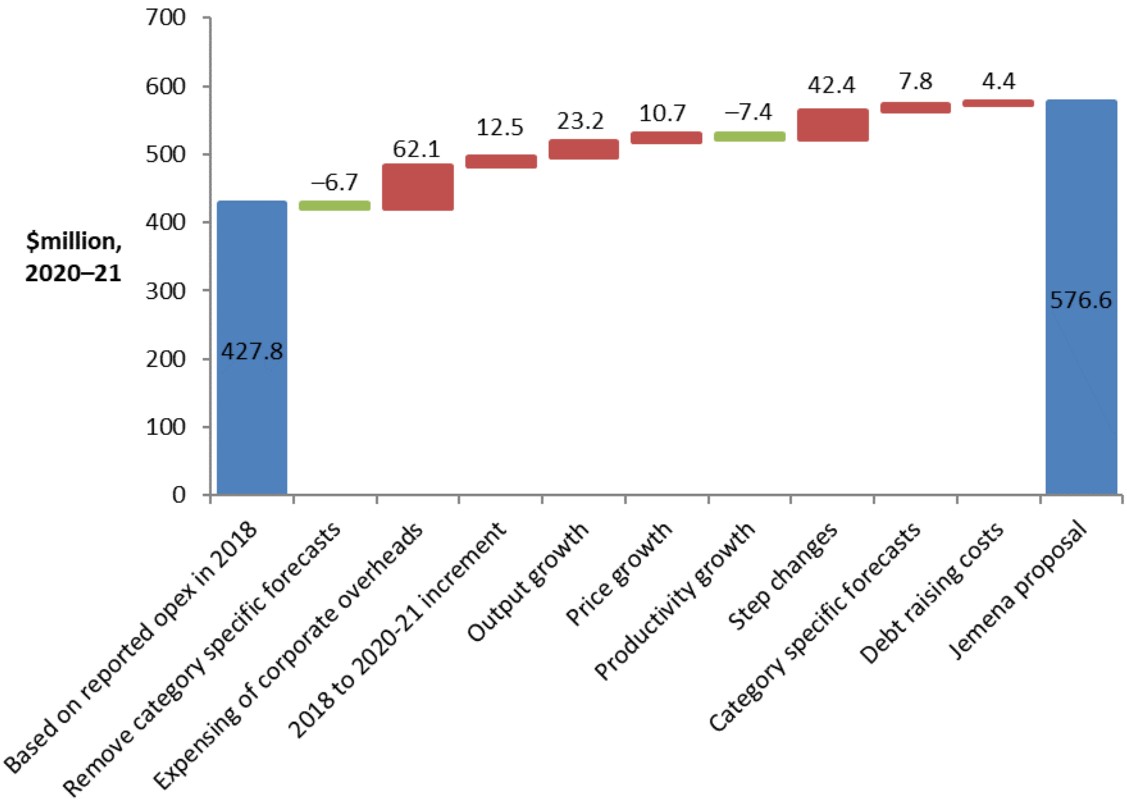
12 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

13 Numbers do not add up to totals due to rounding. Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020.

14 On a like for like basis, after removing the adjustment for the expensing of corporate overheads, this is 15.6 per cent. AER analysis.

15 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 07–15 SCS PTRM FY22–26 - Public*, 24 February 2020.

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



Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020; AER analysis.

During our review process to make this draft decision, Jemena made three updates to its initial proposal:

- It incorporated the proposed adjustment to base opex for the expensing of corporate overheads consistent with its new CAM into the calculation of the final year increment. This reflects that its new CAM will come into effect on 1 January 2021, which falls within the time period covered by the final year increment.[16]
- It updated its opex proposal to hand back the results of its 2019 transformation program more quickly, commencing at the start of the next regulatory control period, resulting in a $20.2 million ($2020–21) reduction to its total opex proposal. It proposed this occur via a negative step change.[17]
- It withdrew its proposed step change in relation to transitional return on debt alignment costs ($0.9 million ($2020–21)).[18]

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16 Jemena, *Information request 037*, 25 June 2020.

17 Jemena, *Information request 052*, 27 July 2020, p. 2.

18 Jemena, *Information request 046,* 17 July 2020.

6.2.1 Stakeholder views

We received six submissions on Jemena's 2021–26 proposal that raised opex issues.

At a high level, multiple submissions noted Jemena's base year opex is in the low range of opex efficiency and questioned its efficiency and whether an efficiency adjustment is required. Many submissions also included comments about the need to account for the impacts of COVID–19 on economic conditions and trend forecasts. They also raised Jemena's step change proposals suggesting the AER should carefully test these proposals to ensure the drivers are consistent with the step change criteria and the proposed costs are efficient.

We have taken these submissions, and any other concerns consumers identified 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 Jemena's opex proposal

Stakeholder	Issue	Description
Consumer Challenge Panel (CCP) 17, Energy Consumers Australia (ECA), Origin Energy, Victorian Community Organisations (VCO)	Base opex	Multiple submissions raised Jemena's base opex: • The CCP17 was not convinced that Jemena's base year is efficient, noting it performs poorly against its peers on MPFP benchmarking and does not have demonstrable opex cost reductions in the current period regulatory control period. It encouraged the AER to evaluate the efficiency of the JEN opex base year.[19] • The ECA supported Jemena's decision to use 2018 as its base year. It was concerned that this base year is relatively less efficient than its peers, but noted that Jemena's transformation program will reduce opex by $9 million per year[20] and its opex in 2018 is well below the AER's allowance.[21] • The VCO considered that the base year opex for Jemena needs to be adjusted downwards to reflect its observed poor productivity (from the partial factor productivity measures). The VCO believes that not imposing base year productivity adjustments makes the purpose of opex productivity benchmarking effectively pointless.[22] • Origin Energy submitted that given Jemena is deemed to be within the efficiency frontier, it considers there is scope for the AER to apply an efficiency adjustment to base opex for Jemena to allow for 'catch-up' to the frontier.[23] The CCP17 and Origin Energy also questioned the choice of 2018 as the base year given the significant amount of time between 2018 and the commencement of the next regulatory control period in July 2021.

19 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, pp. 43-45.

20 This amount is from Jemena's Draft Plan, which has now been updated to be $4 million ($2019–20).

21 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 25.

22 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, p. 56.

23 Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 3 June 2020, p. 4.

Stakeholder	Issue	Description
		CCP17 contend that a base year closer to the commencement of the next regulatory control period might give a better outcome for consumers through knowledge of costs closer to the start of the next period.[24]
CCP17, ECA, EnergyAustralia (EA), Origin Energy	Trend	EA submitted that further trend analysis should be undertaken to reveal persistent over-estimation or under-estimation and to ensure credibility of forecasting methods.[25] 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.[26] 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.[27] ECA submitted it seeks evidence 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.[28] 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.[29]
CCP17, ECA, Origin Energy, 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 these criteria.[30] ECA noted the step change mechanism does not operate symmetrically and it is rare for a business to put forward a negative step changes. It considered this is a further reason why the AER should carefully assess the veracity of each step change.[31]

[24] 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.

[25] EnergyAustralia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals – 31 January 2020*, 3 June 2020, p. 7.

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

[27] Origin Energy, *Submission to Victorian electricity distributors' regulatory proposals,* 3 June 2020, p. 4.

[28] Energy Consumers Australia, *Victorian Electricity Distributors' Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 30.

[29] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 58.

[30] Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposals*, May 2020, pp. 5,12; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026,* June 2020, Attachment 1, p. 9.

[31] Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026,* June 2020, Attachment 1, p. 28.

Stakeholder	Issue	Description
		EA questioned whether allowing numerous opex step changes reflects poorly on the integrity of the AER's revealed cost framework and whether the AER should take a harder line to preserve this.[32]
CCP17, Origin Energy, VCO	5 minute Settlement	The CCP and ECA considered this qualifies as an acceptable step change but questioned the initial costs proposed due to the delay in implementation.[33] The VCO noted the potential for delay and 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.[34]
CCP17, Origin Energy, VCO, ECA	Cyber Security	The CCP17 considered the cyber security step change appears to be a legitimate new and exogenous obligation that is imposed by the Commonwealth Government. It considered the AER should focus on establishing efficient and ongoing costs.[35] The VCO noted Jemena's costs to comply with the requirement as quite modest.[36] Origin Energy raised concerns at the persistent high levels of expenditure relative to the expenditure over the current period, this includes in the area of cyber security. Origin Energy encouraged the AER to closely scrutinise the businesses' forecast ICT expenditure.[37] ECA noted that all five Victorian businesses are subject to compliance with new Federal Government cyber security standards for energy utilities.[38]
CCP17	ESV Levy	The CCP17 noted that some businesses have proposed this is a step change, whereas AusNet Services proposed to remove it from its 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.[39]
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.[40] The VCO notes that AusNet considers there are no costs associated

32 Energy Australia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals – 31 January 2020,* 3 June 2020, p. 8.

33 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, pp. 52–53; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026,* June 2020, Attachment 1, p. 28.

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

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

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

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

38 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–2026*, June 2020, Attachment 1, p. 29.

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

40 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
		with these obligations (or has accepted not to claim the cost as part of its agreement with the Customer Forum), which raises the question as to the cost the other businesses are seeking.[41]
CCP17, AGL, Origin Energy, VCO, ECA	Insurance Premiums	Multiple submissions expressed concerns with the size of Jemena's proposal and question its efficiency.[42] 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.[43] Origin Energy requested confirmation that risk assessments have been appropriately and consistently applied, particularly with respect to insurance premiums.[44]
CCP17, VCO	REFCL	The CCP17 considered some aspects of this have already been approved as contingent projects and it is a legislated requirement. Given this it considered the AER's role is to check the efficiency of implementation.[45] VCO noted the REFCL program has been required by government and has been implemented. It questioned what costs, if any, are already included in base opex for REFCL.[46]
CCP17	Transitional return on debt alignment costs	The CCP17 regarded debt raising costs as an ongoing expense for any network business and so questioned whether this can be justified as a step change.[47]
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.[48] EA expressed concerns that Jemena's 'Future Grid' program will likely overstate the energy only value of PV exports. [49]

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

42 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, p. 68; Energy Consumers Australia, *A review of Victorian Distribution Networks Regulatory Proposals 2021–2026,* June 2020, Attachment 1, p. 29; AGL, *Victorian electricity distribution determination 2021–26*, 3 June 2020, p. 2.

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

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

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

46 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, p. 68, May 2020, pp. 65-66.

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

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

49 EnergyAustralia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals – 31 January 2020,* 3 June 2020, pp. 13-14.

Stakeholder	Issue	Description
CCP17	GSL	The CCP17 is satisfied that Jemena's proposed GSL adjustments are reasonable, recognising that there may be subsequent changes from the Victorian Government who is currently reviewing the scheme.[50]
Origin Energy	Corporate overheads	Origin Energy acknowledged that the AER has approved Jemena's revised CAM and that the proposed expensing of corporate overheads is consistent with the approved CAM. However, it does not consider it appropriate for the AER to simply indicate that the expensing of corporate overheads is consistent with the approved CAM when the underpinning approval process, and its consistency with cost allocation principles set out under the Rules, is unclear.[51] Origin Energy consider that Jemena has failed to demonstrate a causal link between corporate overheads and operating activities and it unrealistic to assume that all unallocated corporate overheads are opex in nature.
Origin Energy, EnergyAustralia	COVID–19	Origin Energy considered 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.[52] 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.[53]

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.[54] 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 allowance 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 Assessment Guideline,[55] and its accompanying explanatory materials.

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50 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26,* 10 June 2020, p. 48.

51 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals,* 3 June 2020, pp. 5-6.

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

53 EnergyAustralia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals – 31 January 2020,* 3 June 2020, p. 6.

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

55 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013.

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[56]

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 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.[57]

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.[58] 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 Assessment Guideline.[59] 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.[60] 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),[61] and more broadly, the National Electricity Objective (NEO).[62] 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.[63]

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

57 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'.

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

59 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 22.

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

61 NER, cl. 6.5.6(a).

62 NEL, s. 7.

63 NER, cl. 6.5.6(c).

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [64]

> 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 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.[65]

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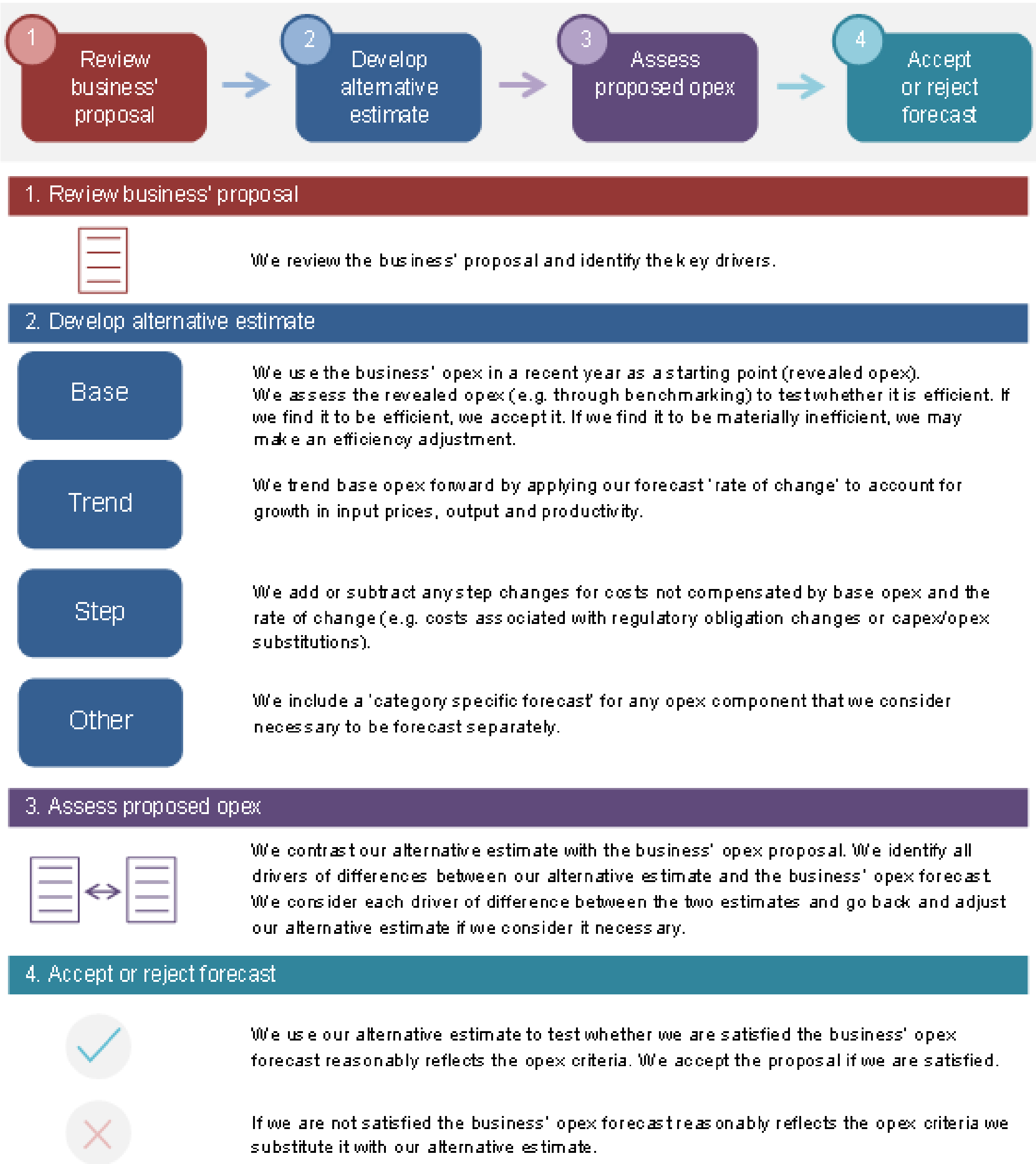
64 AEMC, *Contestability of energy services, Consultation paper*, 15 December 2016, p. 32.

65 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.[66] 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.[67]

66 NER, cl. 6.5.6(e)(5).

67 NER, cl. 6.5.6(e).

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[68] and other assessment techniques to test whether the business is operating efficiently. Where we find a business to be materially inefficient in its base year opex, we will generally apply an efficiency adjustment.

We consider revealed opex in the base year is generally a good indicator of annual 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.[69] 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

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68 NER, cl. 6.5.6(e)(4); AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2019.

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

forecast productivity growth.[70] Productivity measures the change in output for a given amount of input.

The output measures we typically use for distribution businesses are energy delivered, ratcheted maximum demand, customer numbers and circuit length.[71] 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. [72] We stated that we intended to adopt this opex productivity growth forecast when we review the opex forecasts proposed by electricity distributors going forward.[73]

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.[74] 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 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.[75]
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.'[76] Therefore, we consider only new costs that do

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

71 These measures are discussed more fully in our benchmarking reports, see AER, *Annual Benchmarking Report – Electricity distribution network service* providers, November 2019, pp. 58-65.

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

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

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

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

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

not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.[77]

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.[78] 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.[79] Two typical examples are:

- a material change in the business's regulatory obligations
- a prudent and efficient capex/opex substitution opportunity.[80]

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.[81] 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.[82] We stated in the explanatory statement accompanying the Expenditure Assessment Guideline:[83]

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

78 NER, cl. 6.5.6(a).

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

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

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

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

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

> [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 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.[84]

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. An example of a capex/opex trade-off step changes involves replacement expenditure (or "repex").[85] The business should provide robust cost–benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.[86]

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.

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

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

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

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 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 (and so these costs are excluded from the base opex to avoid double counting).

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 Jemena's total forecast opex we also took into account other components of its proposal that could inter-relate with our opex decision.[87] 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
- Jemena's proposed step changes which have an upfront opex and capex investment, and subsequent efficiencies in opex and capex

[87] 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).

- 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.

6.4 Reasons for draft decision

Our draft decision is to include total forecast opex of $499.8 million[88] ($2020–21) in Jemena's revenue for the 2021–26 regulatory control period. Our alternative estimate is $76.8 million ($2020–21), or 13.3 per cent, less than Jemena's proposal of $576.6 million[89] ($2020–21). We are satisfied our alternative estimate of total forecast opex for Jemena reasonably reflects the opex criteria.[90]

Table 6.4 presents the components of our alternative estimate compared to Jemena's proposal, including updates it submitted. The key differences between our alternative estimate of total forecast opex and Jemena's proposal are summarised above in section 6.1 and set out below in sections 6.4.1 to 6.4.7.

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

	Jemena Proposal	Updated proposal	AER draft decision	Difference
Base (reported opex in 2018)	427.8	427.8	422.5	-5.3
Efficiency adjustment	0.0	0.0	-44.9	-44.9
Base year adjustments	62.1	0.0	0.0	-62.1
Final year increment	12.5	83.7	79.2	66.7
Trend: Output growth	23.2	19.6	11.6	-11.6
Trend: Real price growth	10.7	9.2	0.8	-9.8
Trend: Productivity growth	-7.4	-7.5	-5.8	1.6
Step changes	42.4	21.3	32.4	-10.0
Category specific forecasts	1.0	0.9	0.1	-1.0
Total opex (excluding debt raising costs)	572.2	554.9	495.8	-76.4
Debt raising costs	4.4	4.3	4.0	0.4
Total opex (including debt raising costs)	576.6	559.3	499.8	-76.8
Percentage difference to proposal				-13.3%

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

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88 Including debt raising costs.

89 Including debt raising costs.

90 NER, cl. 6.5.6(c) and cl. 6.5.6(d).

Notes: Numbers may not add up to totals due to rounding.

The difference is between Jemena's proposal and our draft decision.

Jemena updated its proposal to incorporate its proposed base adjustment for the expensing of corporate overheads into the calculation of its final year increment as this will occur from 1 January 2021. It also added a negative step change to hand back the results of its 2019 transformation program more quickly, and withdrew its proposed step change in relation to transitional return on debt alignment costs. See section 6.2. Category specific forecasts reflect the net change.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that Jemena would need for the safe and reliable provision of electricity services over the 2021–26 regulatory control period.

Jemena proposed base opex of $85.6 million ($2020–21) reflecting its actual opex in 2018.[91] We consider this is a relatively inefficient forecast, as indicated by our benchmarking results and other analysis, and as a result our alternative estimate does not rely on actual or 'revealed' opex in the 2018 base year. Instead, we have made an efficiency adjustment to actual base year opex to reflect our view of an efficient level of recurrent opex. We discuss the choice of base year in section 6.4.1.1 and set out our analysis of the efficiency of base year opex in in section 6.4.1.2.

6.4.1.1 Proposed base year

Jemena proposed 2018 as its base year. It noted that this reflects reliable, current and audited opex and represents the underlying operating conditions in the current regulatory control period and what is expected in the next regulatory control period.[92] Further, choosing 2018 avoids the impact of transformation costs incurred in 2019, which is consistent with the AER's guidance provided in the draft decision for Jemena Gas Networks' 2020–25 Access Arrangement.[93] It also noted that its opex in 2018 is below the opex forecast set by the AER and its actual opex in 2016 and 2017 meaning it is its lowest opex in the current regulatory control period.

Jemena's proposed base opex in 2018 is $85.6 million ($2020–21). Jemena's 2018 opex reflects updated opex, which it provided to the AER in a resubmitted RIN in November 2019.[94] It is $5.2 million ($2020–21) lower than originally reported and

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[91] This excludes movements in provisions and DMIA payments. Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public*; 25 February 2020; AER analysis.

[92] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, pp. 6-7.

[93] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 7; AER, *Draft Decision, Jemena Gas Networks (NSW) Ltd, Attachment 6,* 25 November 2019, pp. 24–25.

[94] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 10.

reflects the removal of costs that were incorrectly allocated to Jemena Asset Management.[95]

Consistent with our preferred approach, we consider 2018 is an appropriate base year. This is because we consider it is the year in the current regulatory control period that is both most recent and most representative of the base opex required for the next regulatory control period. While there is a more recent year of actual opex available, 2019, this incorporates costs incurred by Jemena as a part of its transformation program which are not recurrent. We also note 2018 opex is not an estimate and has already been audited.

We have updated the base opex amount for 2018 to $84.5 million ($2020–21). The difference between Jemena's proposed amount and our alternative is due to the use of different inflation forecasts. We have used the latest inflation forecasts published by the Reserve Bank of Australia (RBA).[96] We consider these inflation forecasts are the best forecast possible in the circumstances because they are the most up-to-date information available at the time.

6.4.1.2 Efficiency of Jemena's opex

As outlined in section 6.3, and in our Expenditure Forecast Assessment Guideline, our preferred approach for forecasting opex is to use a revealed cost approach. However, we do not rely on the a priori assumption that the business's revealed opex is efficient. We use our top-down benchmarking tools, and other assessment techniques, to test whether the business is operating efficiently historically and particularly in the base year.

In this section, we first outline Jemena's revealed cost performance, before presenting our benchmarking and cost category analysis.

Analysis of Jemena's revealed costs

Figure 6.4 shows Jemena's opex forecast for the next regulatory control period, its actual opex in previous regulatory control periods, our previous regulatory decisions and our alternative estimate that is the basis for our draft decision.

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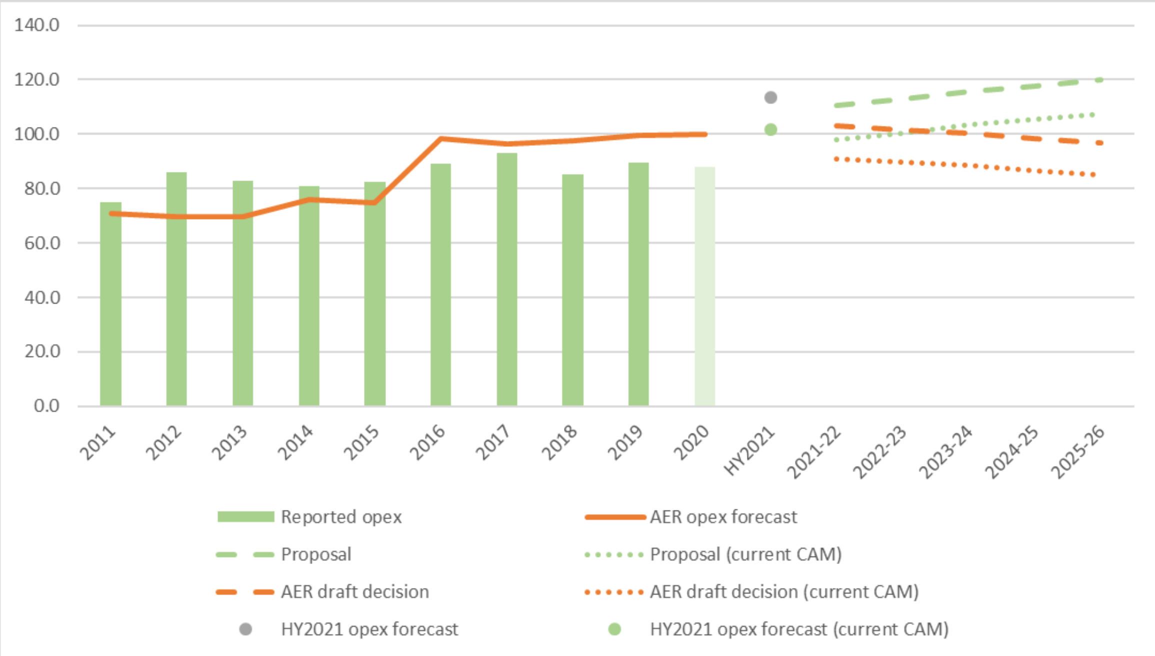
95 Jemena, *Information request 016*, 21 May 2020, pp. 1-2.

96 Reserve Bank of Australia, *Statement on Monetary Policy—Appendix: Forecast*, August 2020.

Figure 6.4 Jemena's opex over time ($ million, 2020–21)



Source: Jemena, IR001 – RIN 5 - *Workbook 1 - Regulatory determination – Public – 10 March 20;* Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER, *Draft Decision, Jemena distribution determination 2021–26, Opex model,* September 2020; AER, *Draft Decision, Jemena distribution determination 2021–26, EBSS model,* September 2020; AER analysis.

Note: We have not included in the 2020 estimate the expensing of corporate overheads under Jemena's new CAM, as this does not occur until 1 January 2021.

To allow a like-for-like comparison across regulatory control periods, we have presented Jemena's historical and proposed opex, as well as our alternative estimate for the draft decision, on the basis of Jemena's current CAM.

Overall we have seen an increasing trend in Jemena's opex over time. Over the current regulatory control period Jemena's expected average annual opex of $89.0 million ($2020–21) is $7.6 million ($2020–21) higher than over the 2011–15 regulatory control period. There was a step up in Jemena's opex in the first two years of the current regulatory control period. In 2017, Jemena's opex was at its highest at $93.0 million ($2020–21) after being around $82 million ($2020–21) per year in the final three years of the last regulatory control period. Opex decreased significantly in 2018 to $85.2 million ($2020–21) before increasing again in 2019 to $89.6 million ($2020–21) in part as a result of the costs incurred as a result of its transformation program (see below).

While increasing over time, Jemena's opex has been below our forecast for the current regulatory control period. Its actual and estimated opex in the current regulatory control period is 9.5 per cent below our opex forecast and its actual opex in the base year of 2018 is 12.6 per cent below our forecast. This is in contrast to Jemena's actual opex in the previous regulatory control period, which was on average 12.8 per cent higher per annum than our opex forecast. This performance is reflected in Jemena's positive EBSS carryovers, as discussed in Attachment 8 of this draft decision. However, as indicated by its benchmarking performance, Jemena has not been able to achieve the same degree of cost reductions as the more efficient distribution businesses.

In this regard we note that Jemena's increasing opex is in contrast to many other distribution businesses, who have achieved cost reductions over time. This comparative performance is reflected in various benchmarking measures, as discussed further below. One possible source of the plateauing of Jemena's opex is in the overheads category, as discussed further below and in Appendix 0. The upward trend in Jemena's historical opex since 2011 would be more evident if we excluded the costs Jemena incurred to address new bushfire risk management requirements in Victoria introduced in response to the 2009 Black Saturday bushfires.

As noted above, in 2019 Jemena implemented a business-wide transformation program to reduce its opex so it could achieve sustained opex reductions over the next regulatory control period and the longer term.[97] Jemena incurred $10.0 million ($2020–21) in costs for the transformation program in 2019.[98] In an update to its initial proposal, Jemena stated that it expects the transformation program to deliver annual savings of $4.0 million ($2020–21) compared to its base year and that it proposes to pass these on more quickly than initially envisaged, starting from 2021–22.[99]

We consider this transformation program and the associated annual savings and benefits indicate Jemena's internal view that there is scope for 'catch-up' to the more efficient businesses.

In line with our approach, we have used our benchmarking tools and other cost analysis to assess and establish whether Jemena is operating relatively efficiently, both over time and in the base year. We conclude that Jemena still under-performs compared to other networks.

Benchmarking the efficiency of Jemena's opex over time

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that provide the same service as a means of assessing their relative performance. Our *2019 Annual Benchmarking Report* includes information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the NEM.[100]

While opex at the total level is generally recurrent, year-to-year fluctuations can be expected. To shed light on Jemena's general level of operating efficiency, we first look

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97 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 8.

98 Jemena, *Information request 052*, 27 July 2020, p. 8; AER analysis.

99 Jemena, *Information request 052*, 27 July 2020, pp. 2, 4.

100 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019.

at the efficiency of Jemena's opex over a period of time, using our top-down benchmarking tools, as well as other supporting techniques. This is followed by looking at the efficiency of base year (2018) opex in particular.

Top-down benchmarking

In terms of historical performance, our benchmarking results from the *2019 Annual Benchmarking Report* indicate that Jemena's opex has been relatively inefficient over the 2006–18 period when compared to other distribution businesses in the NEM.[101] 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.*[102] These results are reported below along with the results from *2019 Annual Benchmarking Report*.

Figure 6.5 shows that over this period Jemena ranks ninth out of 13 distribution businesses based on the average efficiency scores from five economic benchmarking models.[103] This reflects the updates noted above, with the scores ranging from 0.52 (Least Squares Econometrics Translog (LSE TLG) model) to 0.68 (SFA Translog (SFA TLG) model). Jemena's average efficiency score across the five models is 0.60, against the best possible average score of 1.0.[104] We use a 0.75 comparator point to assess the relative efficiency of distribution businesses[105], noting that we adjust this for operating environment factors (OEFs) not already captured in the modelling (which we apply to Jemena in the next section). Allowing for OEFs enables us to account for some factors beyond a distributor's control that can affect its benchmarking performance.

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

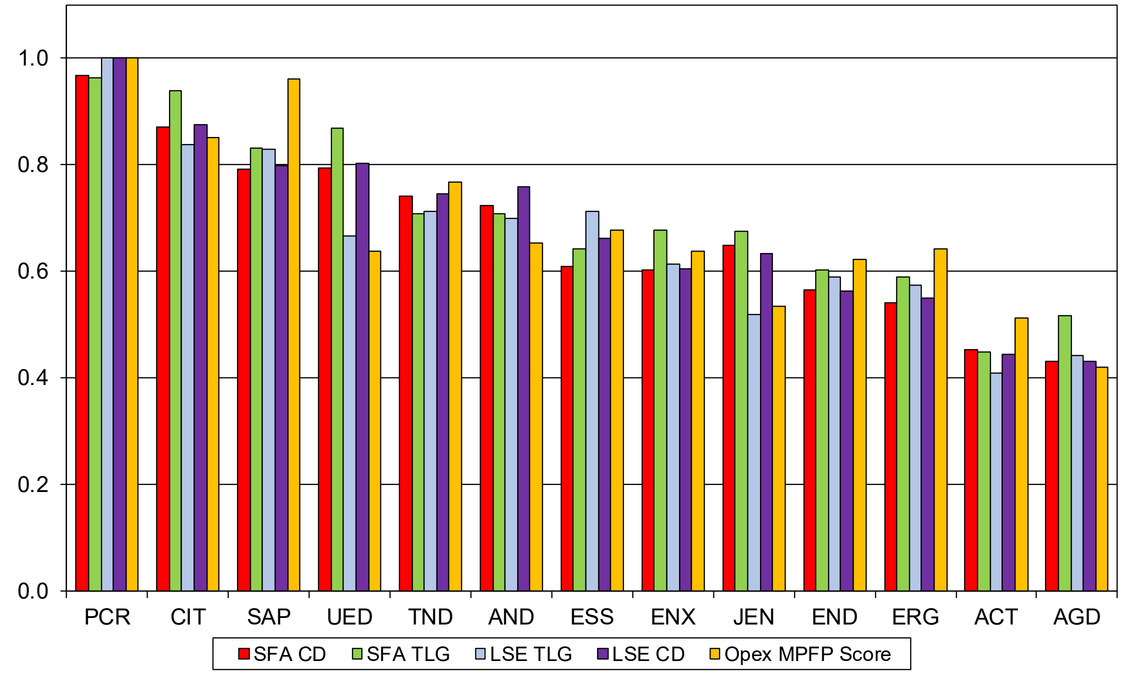
[102] Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020. The data updates include revised opex data for Jemena, CitiPower, Powercor and AusNet Services in some recent years. The updated weights for non-reliability outputs reflect Economic Insights' review of 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 on 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 corrected output weights as a part of our annual benchmarking update to prepare the *2020 Annual Benchmarking Report*.

[103] AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 29; AER, *Annual Benchmarking Report update, Electricity distribution network service providers*, September 2020; AER analysis. The five models are the four econometric models - Cobb-Douglas stochastic frontier analysis (SFA CD), Cobb-Douglas least squares econometrics (LSE CD), Translog stochastic frontier analysis (SFA TLG) and Translog least squares econometrics (LSE TLG) - and the opex multilateral partial factor productivity (MPFP) model.

[104] Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020; AER analysis. Jemena's average score over the 2006–18 period was 0.61 in the *2019 Annual Benchmarking Report.*

[105] As set out further below, we use the efficiency scores from the four econometric models to derive our estimate of efficient base opex and not the opex MPFP efficiency score.

Figure 6.5 Distribution businesses' average opex efficiency scores, 2006–2018



Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report,* 24 August 2020; AER analysis.

Note: JEN in the figure represents Jemena.

It can take some time for more recent improvements in efficiency by previously poorer performing distribution businesses to be reflected in period-average efficiency scores. Considering this, we have also examined Jemena's average performance over the shorter and more recent 2012–18 time period. With the updates noted above Jemena's average score over the 2012–18 period is 0.58,[106] and it is ranked eleventh of the 13 distributors. Again, these results have not been further adjusted for OEFs. This indicates that Jemena has not improved its efficiency relative to its peers over the 2012–18 period, compared with its efficiency over the 2006–18 period. In part this is explained by other distributors improving their performance since 2012.

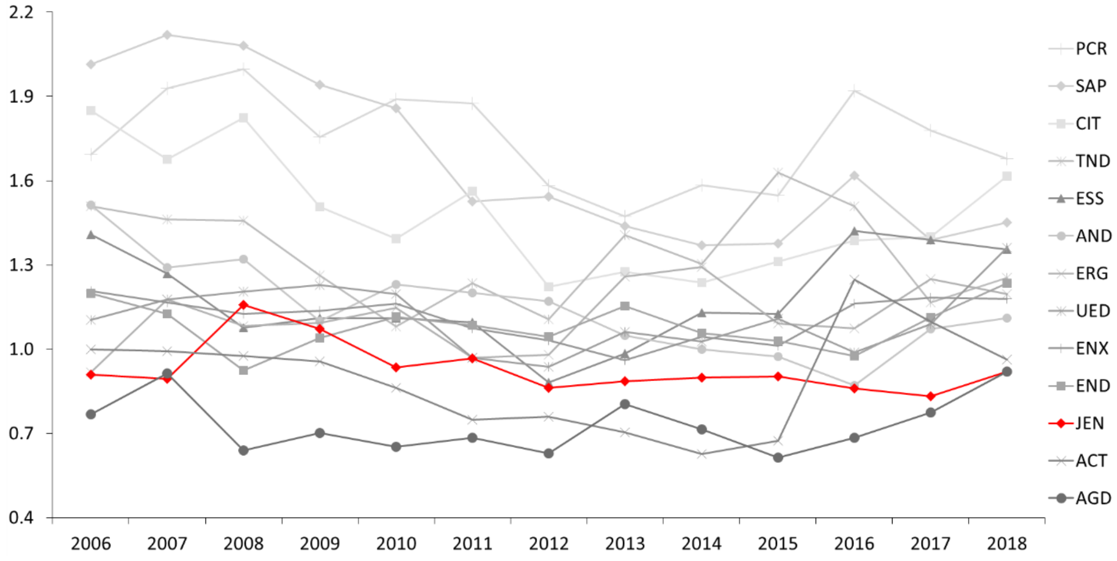
We also use the productivity index techniques to enable comparisons of productivity levels over time and between businesses. The MTFP index measures the total productivity of each business, whereas the opex and capital multilateral partial factor productivity (MPFP) indexes measure the productivity of opex or capital input respectively. We discuss the MTFP and capital MPFP results below where we examine the impact of capex/opex trade-offs on our benchmarking results. As noted above,

[106] This average does not include Jemena's efficiency score for the LSE TLG model, as this is excluded due to statistical properties, and reflects the updates noted above. Jemena's average score over the 2012–18 period was 0.60 in the *2019 Annual Benchmarking Report*.

these results have recently been updated to reflect corrected weights that are used to calculate the output indexes. With the corrected output weights, the rankings of the distribution businesses have changed.

The results from our opex MPFP analysis with these updates can be seen in Figure 6.6 (where a higher index score means more efficient). Jemena has typically ranked among the worst performing distribution businesses in terms of opex MPFP. Jemena's performance has remained fairly constant since 2012, with an increase in measured opex MPFP in 2018. However, as other distribution businesses have improved their performance since 2012, Jemena's ranking has fallen slightly relative to its peers. For Jemena its average ranking over the 2006–18 period with these updates and the corrected weights is eleventh as opposed to ninth under the previous weights used in the *2019 Annual Benchmarking Report*. This is discussed further below in the context of our response to Jemena's proposal and submissions.

Figure 6.6 Opex MPFP (corrected results) by individual businesses, 2006–18



Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020; AER analysis

Partial Performance Indicators and cost category analysis

We have also examined the relative opex performance of Jemena using partial performance indicators (PPIs).[107] As discussed further below, PPIs also formed a part

[107] The PPIs support other benchmarking techniques because they provide a general indication of comparative performance of distribution businesses in delivering a specific output. While PPIs do not take into account the interrelationships between outputs (or the interrelationship between inputs) or account for OEFs, they are informative when used in conjunction with other benchmarking techniques.

of Jemena's submission that it is a cost-efficient business overall.[108] PPIs provide some information about the total and category specific opex performance of a business in delivering a given type of output and may help in understanding potential drivers of relative efficiency or inefficiency. Although they are more simplistic measures, the PPI results can provide further insights and evidence to cross check our top-down economic benchmarking. It is important to note that rankings for PPIs may be affected by factors outside the control of the distribution businesses and must be analysed with caution, with comparisons generally limited to businesses with similar characteristics, e.g. customer density. Where possible, analysis of PPIs includes controlling for customer density to account for these customer density effects when interpreting the results.

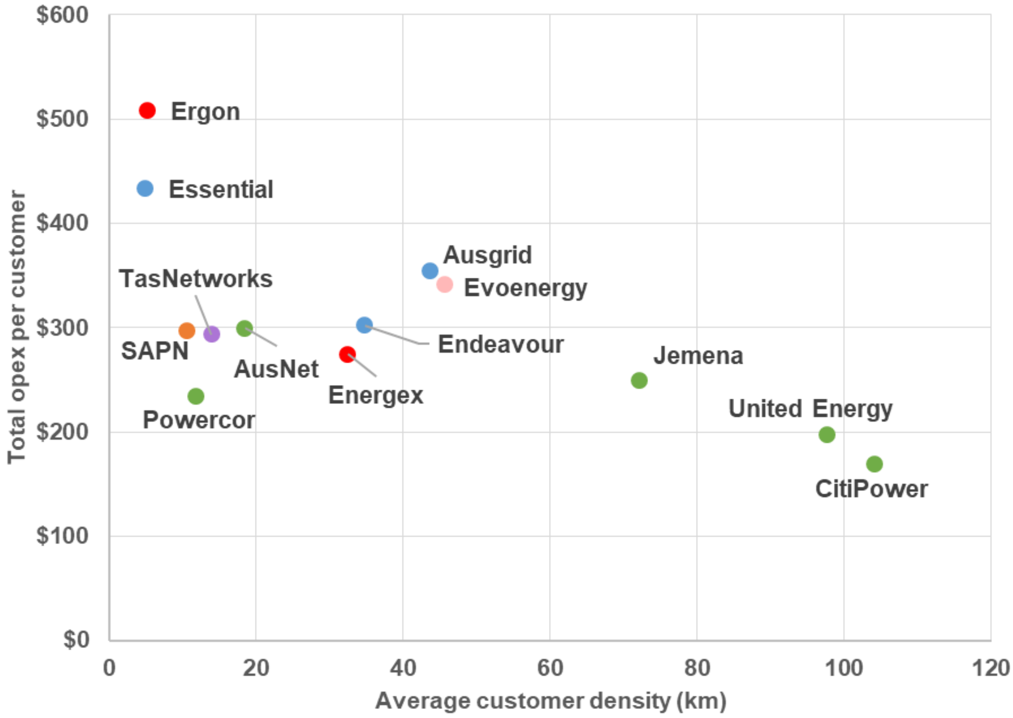
The evidence on Jemena's performance on the range of PPIs is not consistent and depends on the output considered. Across the different PPI cost categories, Jemena tends to perform well on per customer metrics but relatively less well on per circuit length metrics. Urban businesses such as Jemena have denser distribution networks and tend to perform better on per customer metrics than their rural counterparts. As discussed further below in the context of Jemena's submission, the partial nature of PPIs, compared to the ability of the top-down economic benchmarking to consider all outputs holistically, is one of the key reasons we place more weight on the top-down benchmarking.

These results can be seen in Figure 6.7 where Jemena has relatively low average opex per customer, as compared to in Figure 6.8 where it has relatively high average opex per circuit length among the distributors in the NEM (over the 2014–18 time period). However, as noted above, care must be taken drawing conclusions from PPI analysis. For Jemena this is particularly the case given its situation is relatively unique in terms of its customer density.[109] That said, we observe in Figure 6.7 that Jemena's opex per customer is not particularly low when considering it has similar or only marginally lower opex per customer as distribution businesses of less than half its customer density (e.g. Energex, Powercor). We can expect a negative relationship between opex per customer and customer density. This is because, all else equal, the cost of managing the same number of customers connected to a shorter network will tend to be lower. This generally negative relationship is borne out in the figure.

[108] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, pp. 9–14.

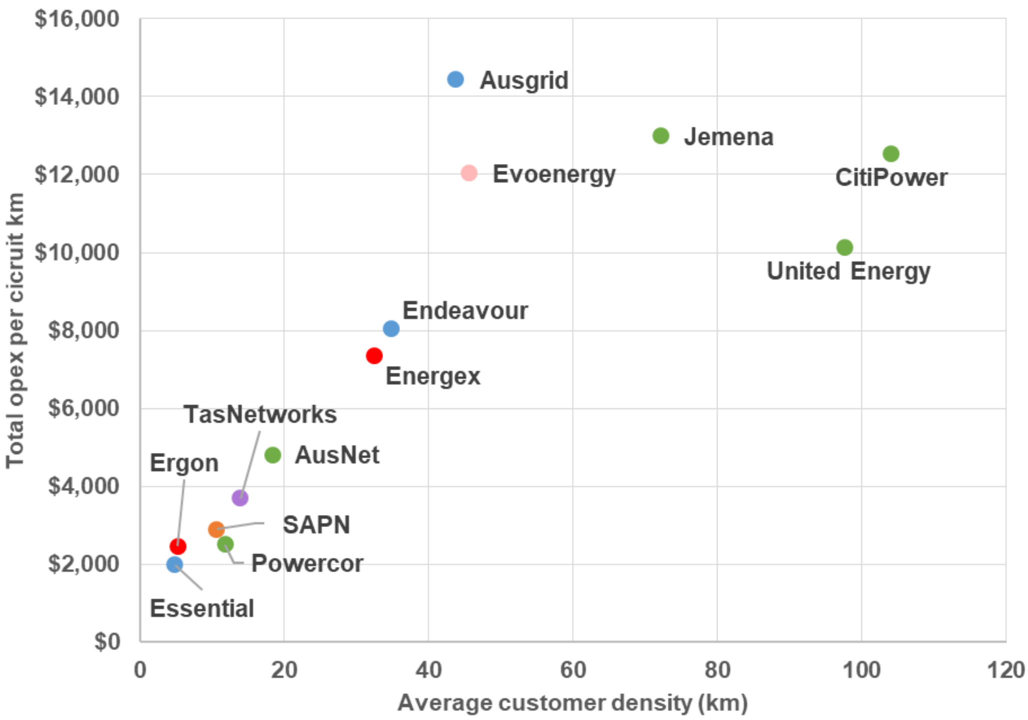
[109] Jemena's customer density (72 customers per km of route length) is different to its closest peers in terms of customer density, who are United Energy (98 customers per km of route length) and Evoenergy (46 customers per km of route length). AER analysis.

Figure 6.7 Total opex per customer, 2014–18, ($2020–21)



Source: AER analysis.

Figure 6.8 Total opex per circuit line length, 2014–18, ($2020–21)



Source: AER analysis.

Similarly, we observe that Jemena's opex per circuit km is higher than CitiPower and United Energy, which are of much higher customer density. We would generally expect that circuit length would have a positive relationship with customer density, as the cost of managing more customers connected to the same network would tend to be higher, all else equal.

The pattern of Jemena's better performance on per customer than on per circuit km is repeated for the main opex cost categories, with the PPI analysis indicating that Jemena has relatively low maintenance, vegetation management and emergency response opex per customer, but that these cost categories are relatively higher on a per circuit length basis. The exception to this is total totex overheads (corporate and network, opex and capitalised) where Jemena does not perform well on either customer or circuit length measures. This analysis suggests that Jemena's overheads are one area of inefficiency. As noted above these results need to be treated with caution. See Appendix A for the total cost, maintenance and total totex overhead PPIs.

We also note that in terms of the cost category data underpinning the PPIs, the ratio of individual cost categories to total opex vary between businesses. For example, over the 2014–19 period Jemena's maintenance, vegetation management and emergency response opex are among the lowest proportions of total opex out of all businesses, whereas it has the highest proportion of opex overheads in the industry.[110] While this may provide further evidence that a source of inefficient costs is its overheads, there is also the possibility that Jemena allocates costs differently to other businesses. The variability in proportions across businesses, that could be attributable to their cost allocation differences, is a further issue that makes it difficult to compare specific cost categories (rather than total opex) across businesses.

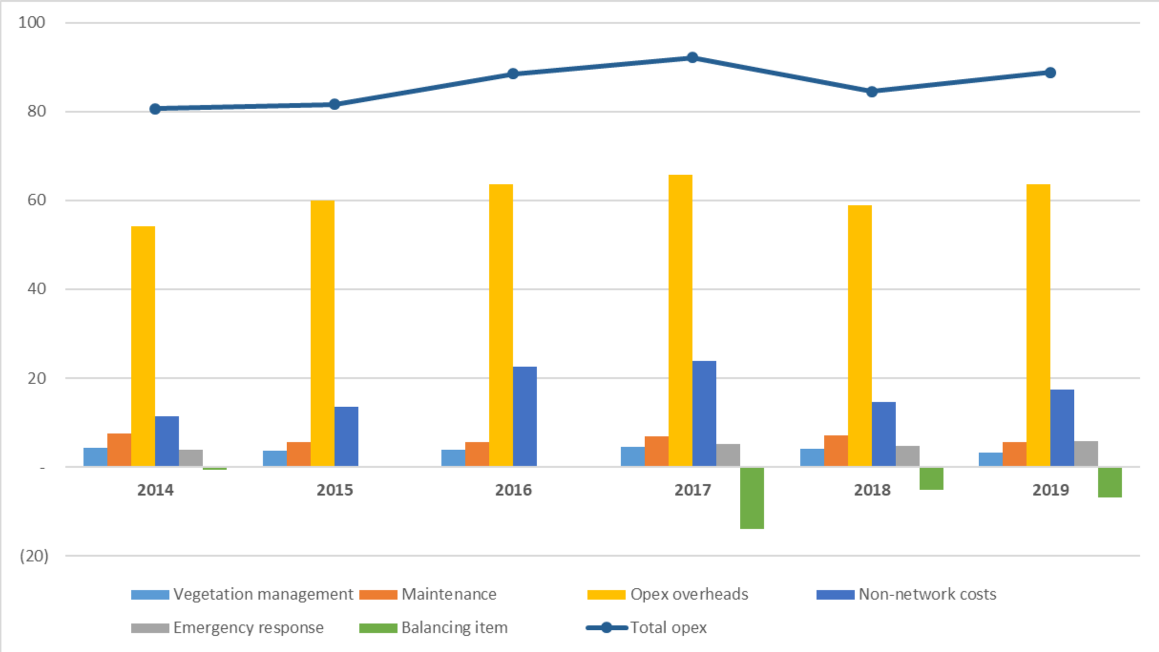
In addition to examining PPIs, we have examined category level costs underpinning them to further understand any changes in Jemena's opex over time and potential sources of inefficiencies compared to other distribution businesses. We have analysed the following opex cost categories over the period 2014–19: maintenance, vegetation management, emergency response, overheads and non-network costs.

Figure 6.9 shows how Jemena's opex cost categories have changed over time. In 2019 Jemena's total opex (the blue line) was over $8.0 million ($2020–21) higher than its opex in 2014, which was predominantly driven by increases in opex overheads and non-network costs. Opex overheads and non-network costs (the yellow and dark blue bars) have been the largest components of Jemena's total opex for each year within the 2014 to 2019 period. All other cost categories account for low proportions of Jemena's total opex, and are unlikely to be material sources of relative inefficiency. For these other cost categories, vegetation management and maintenance costs (the light blue and orange bars) had minor decreases (in terms of their proportions of total opex)

[110] See Table A.1 in Appendix A for this analysis.

in 2019 compared to 2014, whereas annual emergency response costs (the grey bar) were slightly higher in 2019 than in 2014.[111]

Figure 6.9 Jemena's opex cost categories over time ($ million, 2020–21)



Source: Jemena Category Analysis RIN responses 2014 to 2019; AER analysis.

Note: Jemena's emergency response and balancing item values for 2015 and 2016 are confidential and are not included in Figure 6.9 or our analysis.

We have also compared how Jemena's cost categories have changed over time relative to Ausgrid and Evoenergy. These two distribution businesses have historically performed similarly to Jemena under our top-down benchmarking and have customer densities lower than, but close to Jemena. Ausgrid and Evoenergy have achieved reductions in total opex over the period by reducing costs for most categories, particularly opex overheads which is the largest cost category for both businesses. See Appendix B for this analysis. In contrast Jemena's opex overheads have generally increased over the period although Jemena has achieved some reductions in its opex overheads in recent years.

Benchmarking the efficiency of Jemena's base year opex

Given the evidence outlined above about the relative inefficiency of Jemena's opex over the 2006–18 period, and the more recent 2012–18 period, as well as supporting PPI analysis for the 2014–18 time period, we have undertaken additional analysis. This

[111] In addition to the limitations set out above with analysing opex cost categories, a further issue with this data set is that it includes a balancing item (included as a negative, but sometimes positive, item to offset the difference when the cost categories do not sum to total opex).

includes application of our economic benchmarking roll-forward-model to more directly test the efficiency of Jemena’s actual opex in the base year.

The results from our productivity index techniques and econometric opex cost function modelling indicate that when adjusting for OEFs (see below) the presence of material inefficiency in Jemena's 2018 base year opex.

Our productivity index techniques allow us to look at the productivity of each business's total outputs in any particular year. In base year 2018, Jemena is placed equal last on opex MPFP as shown in Figure 6.6. This is an indicator that Jemena's base year opex likely contains a material degree of inefficiency.

Our econometric models produce average opex efficiency scores for distributors across the 2006–18 and 2012–18 periods respectively. Using our roll-forward-model, we convert these period-average results to estimate the level of opex required by a benchmark service provider operating in Jemena's circumstances in 2018, and compare this to the Jemena's actual base year opex. This uses a benchmark comparison point of 0.75. This also adjusts for differences in OEFs between Jemena and the benchmark comparators that are not already captured in the modelling (discussed further below). We outline our approach in Box 1.

Box 1: Our approach to estimating efficient base year opex

To derive our efficient estimate of base year opex for businesses, we find the average of the estimated efficient rolled-forward levels of opex as determined by each of our applicable econometric models (LSE CD, SFA CD, LSE TLG, SFA TLG). This is done using data over the 2006–18 and 2012–18 periods separately, which means two averages are produced. We then compare this to actual opex in the base year.

The first step is to average a business's actual opex over the relevant benchmarking period to find the business’s period-average opex (and where relevant, backcast for the CAM applying in 2013–14, given that our economic benchmarking approach uses opex obtained under this CAM for all the distribution businesses).

We then separately compare the business’s efficiency scores of each econometric model over that period, against a benchmark comparison point of 0.75. This reflects that we consider the upper quartile of possible efficiency scores are efficient, and reflects our conservative approach to setting a benchmark comparison point.

We adjust the benchmark comparison point for potential differences in OEFs between the business and the benchmark comparators that are not already captured in the modelling (discussed further below). The benchmark comparators are those businesses that have average efficiency score above the 0.75 benchmark comparison score. (For both the 2006–18 and 2012–18 benchmarking periods, there are four businesses with average efficiency score at or above 0.75, namely Powercor, CitiPower, United Energy and SA Power Networks.)

Where the business’s efficiency score derived from an applicable model is below the adjusted benchmark comparison point, we adjust its period-average opex (established in the first step) down by the difference between the adjusted comparison point and the efficiency score. This results in an estimate of period-average opex that we consider is not materially inefficient.

This period-average opex estimate is then trended forward from the midpoint of the period to the base year to account for the rate of change. This results in a conservative estimate of efficient opex in the base year, which is compared against actual base year opex. This process is repeated for each econometric model, resulting in a different estimate for each.

The results of this analysis for Jemena are set out in Figure 6.10 for the 2006–18 period and in Figure 6.11. Similarly, in Figure 6.11, our estimates of efficient opex in the base year using our econometric models over the period 2012–18 are shown in green (with an average of $68.6 million ($2020–21)), while Jemena’s actual opex in the base year of 2018 is again shown in red ($81.8 million ($2020–21)). The difference between our average estimate (the blue dashed line) and Jemena's actual opex is $13.2 million ($2020–21).

Figure 6.11 for the 2012–18 period and reflect the updates to the *2019 Annual Benchmarking Report* noted above. In Figure 6.10, our estimates of efficient opex in the base year using our econometric models over the 2006–18 period (as described above) are shown in green (with an average of $70.7 million ($2020–21)), while Jemena's actual network services opex in the base year of 2018 is shown in red ($81.8 million ($2020–21)).[112] The difference between our average estimate (the blue dashed line) and Jemena's actual opex is $11.1 million ($2020–21).

Figure 6.10 Estimates of efficient opex using data over the 2006–18 period ($ million, 2020–21)

Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*; 24 August 2020; AER analysis.

Similarly, in Figure 6.11, our estimates of efficient opex in the base year using our econometric models over the period 2012–18 are shown in green (with an average of $68.6 million ($2020–21)), while Jemena's actual opex in the base year of 2018 is again shown in red ($81.8 million ($2020–21)). The difference between our average estimate (the blue dashed line) and Jemena's actual opex is $13.2 million ($2020–21).

112 We benchmark distribution businesses on the basis of the network services component of standard control services opex, which comprises the majority of standard control services opex.

Figure 6.11 Estimates of efficient opex using data over the 2012–18 period ($ million, 2020–21)

Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*; 24 August 2020; AER analysis.

Note: We exclude the efficiency score for the LSE TLG model for Jemena (and two other businesses, Ausgrid and United Energy) due to issues in relation to the monotonicity requirement (whereby an increase in output can only be achieved with an increase in costs). See Economic Insights, 2019 Annual Benchmarking Report, November 2019, p. 23.

Across the two periods, the average difference between our estimates of efficient opex in the base year and Jemena's actual opex in the base year is $12.2 million ($2020–21), which is 15.0 per cent of Jemena's base year network services opex.

Given the conservatism built in to our benchmarking, particularly the use of a 0.75 benchmark comparator, and further accounting for OEFs not already captured in the econometric modelling, we consider this supports a finding that Jemena's base year network services opex is materially inefficient.

Operating Environment Factors

Service providers do not all operate under exactly the same operating environments. Our economic benchmarking techniques account for differences in operating environments to a significant degree, including the scope of services provided, the share of undergrounding and network densities. However, our benchmarking models do not directly account for all factors, such as differences in legislative or regulatory obligations, climate and geography.

Given this, we also consider OEFs as a part of our benchmarking analysis. This enables us to assess the efficiency of a distribution business's operations on a like-for-like basis to inform our assessment of whether its base year opex is efficient or materially inefficient. We do this by using the OEFs to adjust the benchmark comparison point to account for the operating environment of the distribution business we are assessing (see Box 6.1). This adjusted comparison point is then compared to the business's benchmark efficiency score (from the benchmarking models), allowing us to account for potential cost differences due to OEFs between the business and the benchmark comparison firms. More detail on the mechanics of our approach is contained in past decisions.[113]

Based on a 2018 review carried out by our consultant Sapere-Merz, we have identified a limited number of OEFs that materially affect the relative operating expenditure of each business in the NEM. Sapere-Merz consulted with stakeholders, including the electricity network businesses in undertaking this review.[114]

The material OEFs Sapere-Merz identified are:

1. The higher operating costs of maintaining sub-transmission assets.
2. Differences in vegetation management requirements.
3. Jurisdictional taxes and levies.
4. The costs of planning for, and responding to, cyclones.
5. Backyard reticulation (in the ACT only).
6. Termite exposure.

Table 6.5 shows our calculated OEFs for Jemena for the two benchmarking periods.[115]

Table 6.5 OEF adjustments for Jemena

	2006–18 period	2012–18 period
Sub-transmission (Licence conditions)	-0.2%	-0.0%
Vegetation management (bushfire)	-1.5%	-2.4%
Taxes and levies	0.2%	0.2%
Termite exposure	-0.1%	-0.1%
Total	-1.7%	-2.3%

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER analysis.

113 See AER, *Preliminary Decision, Ergon Energy determination 2015–20, Attachment 7 – Operating Expenditure*, April 2015, pp. 93–138; AER, *Draft Decision, Ausgrid Distribution determination 2019–24, Attachment 6 - Operating Expenditure*, November 2018, pp. 31–33; AER, *Draft Decision, Endeavour Energy Distribution determination 2019–24, Attachment 6 - Operating Expenditure*, November 2018, pp. 27–29.

114 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018.

115 The spreadsheets used to calculate these adjustments are published along with this decision.

These results indicate that Jemena enjoys minor net cost advantages (1.7 per cent and 2.3 per cent over the two benchmarking periods, respectively) relative to the benchmark businesses. We adjust our benchmark comparator point of 0.75 slightly upwards to account for these cost advantages.

The OEF for vegetation management (bushfire) is the only OEF adjustment of material size in terms of the OEFs that we are applying to Jemena in this draft decision. This OEF exists to account for the differences in opex between distributors due to differences in bushfire risk for clearing vegetation, in this case between Jemena and the comparator networks.[116] We have applied the approach that we recently applied in our Ergon Energy determination, which was a re-application of the approach used in our Queensland 2015 decisions.[117] This approach calculates the vegetation management OEF for the relevant business by quantifying the cost impact of vegetation management regulations introduced in Victoria after the 2009 Black Saturday bushfires. The increased opex incurred as a result of the new regulations is used as a proxy for the differences in costs of managing bushfire risks in Victoria compared to other states. While as a Victorian business Jemena also faced these additional vegetation management obligations and costs, it is predominantly an urban business so is relatively less affected by bushfire risk obligations.[118]

We have also considered whether capitalisation practices (the use and/or reporting of opex and capex by businesses, which covers both opex/capex trade-offs and capitalisation policy) could potentially be a material OEF for Jemena. The issue of differing capitalisation practices was put forward by Jemena as a key explanation for its opex efficiency score performance. We have not included an OEF for Jemena's capitalisation practices in our current assessment. Our reasons for this are discussed in the next section.

Jemena's and other stakeholders' submissions on base opex efficiency

In its proposal and information request responses, Jemena submitted that its base year opex is efficient and that its opex benchmarking scores need to be interpreted with caution.

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116 In past decisions, we have also calculated a second vegetation management OEF, termed division of responsibility, in relation to the cost disadvantage in the scale of vegetation management responsibility compared to the benchmark comparator businesses in Victoria and South Australia. This was because in Queensland distribution businesses are responsible for vegetation clearance from all network assets, whereas in Victoria and South Australia, other parties such as councils, landowners and roads authorities are responsible for some vegetation clearance. See AER, *Draft decision, Ergon Energy distribution determination 2020–21 to 2024–25 Attachment 6*, October 2019, pp. 83–85. Given Jemena is a Victorian network, its cost advantage for this OEF under our calculation method is zero.

117 AER, *Preliminary Decision*, *Ergon Energy determination 2015−16 to 2019−20, Attachment 7 − Operating Expenditure*, April 2015, p. 200; AER, *Final decision, Ergon Energy distribution determination 2020 to 25 Attachment 6, Operating expenditure*, June 2020, pp. 41–44.

118 More details of how this OEF adjustment is calculated is shown in the calculation spreadsheet which we have published along with this decision.

Jemena submitted in its initial proposal that, while benchmarking results are important and the AER should continually develop these techniques, these techniques should not be applied deterministically. Rather, the AER should take a holistic view of overall cost efficiency. Jemena submitted that, on the basis of its strong total cost benchmarking performance—including total cost per customer PPI and MTFP— and its performance on opex cost category PPIs, it believes it is a cost-efficient business overall.[119]

In particular, it submitted that the variability in Jemena's opex benchmarking ranking may be due to a range of factors, such as:

- models that may not perfectly allow for its opex drivers
- changes in output weights
- revisions to the international dataset
- differences in capitalisation policies and capex/opex trade-offs or
- operating environment conditions such as it having a high proportion of overhead transmission lines and having a high proportion of urban versus rural customers.[120]

It further noted that outcomes from efficiency methods and approaches are sensitive to assumptions and weights, and that the AER has noted its intent to review its economic benchmarking practice, with a focus on:

- the implications of cost allocation and capitalisation differences on the benchmarking results
- the review of benchmarking output specifications
- the choice of benchmarking comparison point
- improving and updating the quantification of material OEFs.[121]

Jemena submitted that capex and opex performance should be evaluated together in determining the overall efficiency of a business to take account of any capex/opex trade-offs. Jemena argued that its low opex benchmarking scores are not a reflection of opex inefficiency, but rather that, compared to most businesses, it favours the use of opex over capital inputs.[122]

Jemena further stated "[although] the current benchmarking approach provides incentives for DNSPs to improve cost efficiency, it does not capture these interactions and trade-offs between capex and opex." [123] Jemena further noted that "…results from

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119 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, pp. 9–12.

120 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 11.

121 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01, Standard Control Services - Operating Expenditure - Public*, 24 February 2020, pp. 11–12.

122 Jemena, *Information request 043*, 15 July 2020, pp. 2-4.

123 Jemena, *Information request 043*, 15 July 2020, p. 2.

econometric models should be used with care as they do not reflect capex-opex trade-offs and provide varied efficiency levels." [124]

Jemena explained that, in principle, benchmarking analysis assessed on a total cost basis will account for such trade-offs, enabling distribution businesses to choose the most efficient approach without needing to consider the positive or negative incentives around these choices. Jemena considered that it is overall cost efficient based on its MTFP and total-cost PPI performance and that these measures should have a substantial weight in deciding on an efficient base year. It further submitted that Jemena's opex/capital cost ratio is the highest of the 13 distribution businesses, reflecting that it adopted more operating solutions rather than relying on the flow of capital services to deliver a lower total cost to customers.[125]

As a crosscheck of its assessment that its base year opex is efficient, Jemena submitted that its efficiency score would rank in the top four of 13 businesses once the different characteristics of urban and rural networks are accounted for. It did this by re-estimating the SFA CD model by splitting the distribution businesses into urban and rural sub-samples based on customer density (where businesses are designated as rural if they have less than 20 customers per km of circuit length, and as urban otherwise).

We also received submissions from several stakeholders who expressed concerns with the efficiency of Jemena's base year opex. The VCO[126] and Origin Energy[127] consider we should apply an efficiency adjustment to Jemena's base opex, and the CCP17[128] is not convinced Jemena's base year opex is efficient. Alternatively we note that the ECA stated that while Jemena's base year opex is less efficient than its peers, it does not object to it because Jemena's transformation program will reduce opex by $9 million per year and its opex in 2018 is well below the AER's allowance.[129] We understand that the ECA is referring to an old figure reflected in Jemena's draft plan and these benefits are lower at $4.0 million ($2020–21) per annum.[130]

Our response to Jemena's submissions

We understand Jemena's position to be that it should be regarded as an efficiently operated business when taking into account a variety of efficiency measures, where relatively poor economic benchmarking of opex is offset by good performance on other measures (total PPIs and MTFP/capital MPFP). Jemena considers that this

[124] Jemena, *Information request 052*, 27 July 2020, p. 6.

[125] Jemena, *Information request 043*, 15 July 2020, p. 4.

[126] Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal,* May 2020, p. 56.

[127] Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 3 June 2020, p. 4.

[128] CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, pp. 43-45.

[129] Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 25.

[130] Jemena, *Information request 052,* 27 July 2020, pp. 3-4.

performance, in turn, can be largely attributable to two features of the AER's economic benchmarking:

- Imperfections in the AER's benchmarking models.
- Inadequate consideration of the impact of Jemena's capitalisation practices, in particular opex/capex trade-offs.

Taking into account issues with our economic benchmarking models and Jemena's circumstances

As explained in our benchmarking reports, our economic benchmarking models capture the most important drivers of opex for distribution businesses.[131] While we recognise Jemena's relatively good performance on some PPIs, we have placed less weight on PPIs compared to the top-down economic benchmarking, for several reasons.

- As compared with the PPIs we consider that top-down economic benchmarking takes a more holistic view of distribution businesses' output that covers all the functions that customers value, including circuit length and customer numbers. This point can be illustrated by Jemena's better performance on customer number PPIs relative to circuit length PPIs, as shown above and in Appendix A. Economic benchmarking allows an appropriate weighting of outputs and factors to be applied to give an overall efficiency assessment.
- Jemena's customer density makes it more difficult to compare its PPIs to other businesses as there are no other businesses with directly similar customer density.
    - In its proposal, Jemena applied a line of best fit to control for differences in customer density between businesses. This approach must be analysed with caution due to the simplicity of the assumption and technique and the small sample used. It assumes a linear relationship between customer density and the output in the PPI. This assumption is simple but may not necessarily reflect the underlying relationship. The estimated line of best fit is based on a small sample of 13 data points, and fails to account for the presence of inefficiency in the average line estimated. Due to these concerns, we have compared businesses against their close peers although this is difficult for Jemena as it is an outlier. Because of this we have treated Jemena's extrapolated PPIs results with caution.
    - While we consider the exact relationship between the PPI in question and customer density to be unknown, as noted above we do not consider that Jemena's per customer and per circuit length PPI performance is as strong as claimed by Jemena when taking into account the broad relationship with customer density.

131 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, pp. 55–65.

- As shown in the category analysis above, Jemena's overheads form a relatively large proportion of its opex compared to other businesses and on overheads PPIs Jemena's performance is not among the top businesses.
- In relation to Jemena's econometric modelling that estimates the rural and urban sub-samples separately, this is a similar technique to the one Frontier Economics developed for Ergon Energy in the Ergon Energy 2020–25 revenue determination.[132] We maintain our concerns with this approach, as stated in our final decision.[133] In summary, this analysis hinges on an arbitrarily selected point (20 customers per km) at which urban becomes rural. This can pose problems for medium-density firms on the boundary. In addition, because of the logarithmic form of our economic benchmarking models and the inclusion of customer numbers and line length outputs, allowance is already made for differences in customer density, reducing the need for separate treatment of rural and urban distributors. Accuracy of estimation is also improved by having diverse characteristics in the larger sample.
- More generally, we recognise the modelling and data imperfections of (any) benchmarking. This is the key reason why we adopt a conservative approach to setting the benchmark comparison point. In addition, we make post-modelling OEF adjustments for exogenous factors that are not captured directly in the models.

Capitalisation practices

We have considered the impact of capitalisation practices (the use and/or reporting of opex versus capex) on our opex benchmarking in response to the issues Jemena (and the other Victorian businesses) raised and as part of the continuous improvement of our benchmarking.[134] This is because it could impact the like-with-like comparability of our economic benchmarking. We have also considered the implications of Jemena’s capital MPFP and MTFP benchmarking performance for assessing opex efficiency.

Our analysis is presented in Appendix C. In summary, on balance, we do not consider the impact of Jemena's capitalisation practices have a significant impact on our opex benchmarking results. While capitalisation practices could explain some of Jemena's poorer opex performance, we do not consider it is the main explanation. This is because:

- We consider that the relationship between capital inputs and opex is implicitly captured in our opex benchmarking models as a result of the high correlation between capital inputs and the outputs used as explanatory variables in these

[132] Frontier Economics, Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex, December 2019, p. 10.

[133] AER, *Final decision, Ergon Energy distribution determination 2020 to 2025 Attachment 6, Operating expenditure*, June 2020, pp. 37–38.

[134] We highlighted this issue in our *2019 Annual Benchmarking Report* as one of our focus areas of continuous improvement of our benchmarking toolkit.

models. Therefore, the omission of capital inputs in our opex benchmarking models is unlikely to significantly affect the opex efficiency results.

- If comparatively Jemena has historically favoured opex over capital relative to other businesses, then this could be one of the drivers for its relatively poorer opex benchmarking performance and relatively better capital performance. However, we have not been able to establish definitively that it has favoured opex over capital relative to other businesses based on our examination of high level indicators of opex-to-capital usage. In particular, Jemena is found to be close to the comparator average on one of the ratios (opex/totex) but is relatively high on two other ratios (opex/total cost and opex/total input). Each of these ratios has imperfections and we do not consider there is clear evidence that Jemena's relative mix of opex and capital is materially different to the benchmark comparators.
- We also do not consider Jemena's performance on total-cost (MTFP and total-cost PPI) and capital productivity benchmarking provides strong evidence of the impact of opex/capital trade-offs on the opex benchmarking scores, particularly in light of the recent update of the results. While Jemena ranked relatively highly across both measures as published in our *2019 Annual Benchmarking Report*, we have examined the impact 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.[135] With these changes, and particularly inclusion of the corrected output weights, the MTFP and MPFP rankings of the distribution businesses have changed. For Jemena, its MTFP performance with the corrected weights is generally in the bottom four to five of 13 distribution businesses over the 2006–18 period, and its capital MPFP ranking has also dropped out of the top four to be among the mid-ranked businesses.

The issue of capitalisation is, however, an area of ongoing work, and we welcome Jemena's and other stakeholders' feedback on the analysis and draft position outlined here.

Efficiency adjustment to Jemena's final year opex

Taking the above analysis into account, we have concluded on balance that Jemena's actual base year opex is not at a level that is consistent with what an efficient benchmarked service provider operating in Jemena's circumstances would require to deliver its network services. Given the conservatism built into our benchmarking approach, including the use of 0.75 as the efficiency benchmark and accounting for OEFs, we consider that Jemena's base year opex is materially inefficient. Consequently, to determine our alternative estimate of base opex we have made an efficiency adjustment to Jemena's estimated final year opex[136] to establish a level of opex that we consider reflects an efficient distributor's opex.

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135 See Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020.

136 This adjustment is applied to estimated final year opex, which via the final year formula reflects the other adjustments to base year opex discussed in section 6.4.2.

The size of the efficiency adjustment we have made to Jemena's estimated final year opex is 15.0 per cent. We have derived this from the results of our benchmark modelling of estimated efficient opex, as described above.

Jemena submitted updates to its initial proposal, which included a negative step change proposal of $4.0 million per year ($2020–21) ($20.2 million ($2020–21) over the next regulatory control period). This was based on savings realised in the first half of 2020 from its 2019 transformation program and future expected reductions to opex.[137] This would be equivalent to a 4.7 per cent efficiency adjustment applied to its base year opex.

As set out above, our assessment of Jemena's base year opex suggests a 4.7 per cent reduction would not be sufficient to reduce it to an efficient level.

Transition to lower cost base via a glide path

We have used a glide path to transition Jemena from its current opex levels to the more efficient opex level adopted in this draft decision. This involves linear reductions to base opex over the next regulatory control period, so that the 15.0 per cent reduction is fully realised by the last year of the period. In practice, this means that the efficiency adjustment in the first year of the next regulatory control period is 3.0 per cent, 6.0 per cent in the second year (as a further 3.0 per cent efficiency adjustment is applied), and so on so that the full 15 per cent is applied in the final year of the period.

While we consider base year opex should be 15 per cent lower, we also consider that it will take time and involve costs for management to implement the required programs over the next regulatory control period. Based on the initiatives Jemena undertook in its 2019 transformation program, this may involve incurring costs in relation to redundancies (the major proportion of the costs), transformation program management, and systems and processes implementation costs.[138] We consider that the glide path provides for the prudent, practicably achievable targets that will allow Jemena to achieve cost efficiency while at the same time maintaining the quality, reliability, security and safety of services over the period.

The 15 per cent adjustment when combined with the glide path lowers our alternative estimate of opex by $44.9 million ($2020–21) over the next regulatory control period compared with Jemena’s initial proposal which did not include an efficiency adjustment.

As noted above, Jemena undertook a transformation program in 2019 and has proposed to hand back the results and expected cost savings from this program more quickly, commencing at the start of the next regulatory control period. This results in a

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[137] Jemena, *Information request 052*, 27 July 2020, pp. 2-5.

[138] Jemena, *Information request 052*, 27 July 2020, pp. 8–9.

$20.2 million ($2020–21) reduction to its total opex proposal,[139] narrowing the difference to our alternative estimate. Taking into account Jemena's update to reduce its opex forecast by this amount means our efficiency adjustment ($44.9 million ($2020–21)) is $24.7 million ($2020–21) more than Jemena included in its updated proposal.

6.4.2 Final year increment

Our standard practice to calculate final year opex is to add the difference between the opex allowance for the final year of the preceding regulatory control period and the opex allowance for the base year to the amount of actual opex in the base year.[140] As a result of the six month extension to the current regulatory control period, we have updated our final year increment calculation by replacing the opex allowance for the final year of the preceding regulatory control period to the annualised half year 2021 allowance.

By forecasting opex in this way, the opex forecast assumes Jemena makes no efficiency gains between the base year and the final year, being 2020. This allows Jemena to retain the efficiency gains it makes in 2020 through the opex forecast.[141] This is consistent with the decision to apply the EBSS during the 2016–20 regulatory control period.[142]

6.4.2.1 Expensing of corporate overheads

As noted in section 6.2, in its initial proposal Jemena adjusted its base year opex to recognise the change in its CAM from 1 January 2021 to treat all corporate overheads as opex. This increased its base opex by $12.4 million ($2020–21) per annum or $62.1 million ($2020–21) over the next regulatory control period.[143] It subsequently updated its initial proposal to incorporate this proposed adjustment to base opex into the calculation of its final year increment. This reflects that its new CAM will come into effect on 1 January 2021, which falls within the time period covered by the final year increment.[144]

We agree with Jemena's updated proposal to include this adjustment to base opex into the calculation of the final year increment given that the new CAM will begin to apply at the start of the six month extension to the current regulatory control period. In establishing our alternative estimate we have included an adjustment to the final year

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139 Jemena, *Information request 052*, 27 July 2020, p. 2.

140 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013, p. 64.

141 AER, *Expenditure forecast assessment guidelines for electricity distribution*, November 2013, pp. 22–23.

142 AER, *Jemena distribution determination 2016 to 2020*, *Final decision, Attachment 9, Efficiency Benefit Sharing Scheme*, May 2016, pp. 6–7.

143 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 15; Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public*, 25 February 2020.

144 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 15.

increment of $11.8 million ($2020–21) to account for Jemena's new CAM and the change in the treatment of corporate overheads. This increases Jemena's base opex by $59.1 million ($2020–21) over the next regulatory control period.

We are satisfied that the CAM adjustment is consistent with Jemena's new CAM[145] which the AER approved in May 2019.[146] Our alternative estimate is $0.6 million ($2020–21) ($2.9 million ($2020–21) over the regulatory control period) less than Jemena's estimate because we have:

- used the latest inflation forecasts published by the RBA[147]
- estimated the CAM year adjustment using the historical average of capitalised corporate overheads from the period 2016 to 2018. This is different from Jemena's approach as Jemena estimated the CAM adjustment using the same historical average, but then used this average to forecast capitalised corporate overheads for the next regulatory control period. Our alternative estimate does not include this step as corporate overheads will not be capitalised in the next regulatory control period.

Using an average of Jemena's historical capitalised corporate overheads ensures the overheads we include in our alternative estimate are not overly influenced by factors in a single year. We have not included Jemena's capitalised corporate overheads from 2019 within our averaging period as the costs are materially different from previous years, and do not appear to represent a recurrent level of capitalised corporate overheads. Jemena confirmed this and explained that 2019 capitalised corporate overheads were lower because it received a higher amount of gifted assets than expected, which resulted in a one-off reduction in their capitalised corporate overheads.[148]

We have applied the CAM adjustment by including an additional $5.9 million ($2020–21) in our opex forecast for the first six months of 2021 (which is then annualised). This approach is consistent with Jemena's update to its initial proposal.[149]

Origin Energy submitted it does not consider it appropriate for the AER to simply indicate that the expensing of corporate overheads is consistent with the approved CAM when the underpinning approval process, and its consistency with cost allocation principles set out under the Rules, is unclear.[150] Origin Energy requested that the AER explain in detail how Jemena's CAM and specifically the expensing of corporate overheads to allow consistency with statutory accounting practices meets the AER Guidelines or the cost allocation principles set out in clause 6.15.2 of the Rules.[151]

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145 Jemena, *Cost allocation methodology,* 29 March 2019.

146 AER, *Final Decision, Jemena Electricity Networks (Vic) Ltd Revised Cost Allocation Method*, May 2019, pp. 9-10.

147 Reserve Bank of Australia, Statement on Monetary Policy—Appendix: Forecast, August 2020.

148 Jemena, *Information request 039,* 30 June 2020, p. 2.

149 Jemena, *Information request 037*, 25 June 2020.

150 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals*, 3 June 2020, pp. 5-6.

151 Origin Energy, *Submission to Victorian electricity distributor's regulatory proposals*, 3 June 2020, pp. 5-6.

We are not required to consider a distribution network service provider's capitalisation policy in our assessment of its CAM. This is because capitalisation policy is not a CAM requirement under the NER, nor is it mandated by our Cost Allocation Guidelines. In past decisions where businesses have included capitalisation policies in their proposed CAMs, we have examined them at a high level to ensure they are broadly aligned and not inconsistent with the required criteria.[152]

6.4.3 Base adjustments

As set out in section 6.2, Jemena initially proposed to adjust its base year opex to recognise the change in its CAM from 1 January 2021 to treat all corporate overheads as opex. It subsequently updated its proposal as this change occurs within the six month extension to the current period and this proposed change is discussed above in section 6.4.2.

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.[153]

Jemena broadly applied our standard approach to forecasting the rate of change.[154] It proposed:

- Price growth: to adopt input price weights of 59.7 per cent for labour and 40.3 per cent for non-labour. Jemena applied an average of Deloitte's wage price index (WPI) forecasts for the New South Wales utilities sector prepared in June 2019[155] and BIS Oxford Economics' forecast for Victoria utilities sector prepared in September 2019.
- Output growth: to adopt our approach of using output weights from all five benchmarking models (based on its forecasts of growth in customer numbers, circuit line length, ratcheted maximum demand and energy throughput). It adopted the output weights set out in our *2019 Annual Benchmarking Report*.
- Productivity growth**:** to use our 0.5 per cent per year productivity growth forecast.[156]

Jemena's rate of change contributes $26.4 million ($2020–21), or 5 per cent of its proposed total opex forecast of $576.6 million ($2020–21). This equates to opex

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[152] See Citipower, C*ost allocation method,* April 2014; AER, *Final decision CitiPower and Powercor Revised Cost Allocation Methods*, 17 October 2014, pp. 8-10.

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

[154] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 16.

[155] At the time of its proposal there were no Victorian utilities WPI forecasts available for Jemena and it used the New South Wales forecasts instead.

[156] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 16.

increasing by around 1.4 per cent each year over the 2021–26 regulatory control period.[157]

We include a rate of change that increases opex by 0.6 per cent each year in our alternative estimate (see Table 6.6 for our alternative estimates of each component of the rate of change, and Jemena's proposal). We have set out the reasons for our alternative estimate, and the difference compared to Jemena's forecast, below.

We have received five submissions relating to the proposed rate of change.[158] The key concern raised by stakeholders was the impact of COVID–19 on the accuracy of the forecasts. We have taken these concerns into account when assessing price growth by relying on Deloitte's utilities WPI growth forecasts for Victoria only (for the draft decision) and when assessing output growth by updating the forecasts for three of the individual output measures. Some submissions also encouraged us to examine the impact of the increase in the super guarantee on labour price growth, which we have done below.[159]

Table 6.6 Forecast rate of change, per cent

	2021–22	2022–23	2023–24	2024–25	2025–26
Jemena's proposal					
Price growth	0.6	0.6	0.6	0.6	0.6
Output growth	1.2	1.3	1.3	1.3	1.3
Productivity growth	0.5	0.5	0.5	0.5	0.5
Overall rate of change	**1.3**	**1.4**	**1.5**	**1.4**	**1.4**
AER draft decision					
Price growth	0.1	–0.1	0.0	0.2	0.6
Output growth	0.6	1.0	1.1	1.1	1.1
Productivity growth	0.4	0.5	0.5	0.5	0.5
Overall rate of change	**0.4**	**0.3**	**0.6**	**0.8**	**1.2**
Overall difference	**–0.9**	**–1.1**	**–0.9**	**–0.6**	**–0.3**

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157 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, pp. 16-17.

158 CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, pp. 56–58; Origin Energy, *Submission to Victorian electricity distributors regulatory proposals*, 3 June 2020, pp. 4–5; Energy Australia, *Victorian Electricity Distribution Determinations 2021–26 – regulatory proposals – 31 January 2020*, 3 June 2020, p. 7; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 30; Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, pp. 4, 62–64.

159 Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 30.

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

6.4.4.1 Forecast price growth

We have included forecast average annual real price growth of 0.2 per cent in our alternative opex estimate. This compares to Jemena's proposed average annual price growth of 0.6 per cent.[160] This increases our alternative estimate of total opex by $0.8 million ($2020–21), instead of $10.7 million ($2020–21) as proposed by Jemena. The magnitude of the difference in dollar terms is due to three elements:

- Our forecast average annual real price growth is lower than Jemena's.
- Our forecast real price growth does not include the impact of the six month extension period, which Jemena's proposal included.[161]
- Our forecast growth path in the first three years is close to zero before increasing to 0.6 per cent in the final year, whereas Jemena's proposed growth path is relatively constant around 0.6 per cent.

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 utilities WPI for Victoria as forecast by Deloitte.[162] Jemena used our standard approach of averaging WPI growth forecasts from Deloitte and BIS Oxford Economics.[163] We discuss below our reasons for not averaging the Deloitte and BIS Oxford Economics forecasts. Unlike Jemena, we have accounted for the legislated superannuation guarantee increases in our labour price growth forecasts.
- Both we and Jemena applied a forecast non-labour real price growth rate of zero.[164]
- 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 calculation used to determine the weights we have previously used.[165] In contrast,

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[160] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 18.

[161] We note that Jemena submitted an updated opex model excluding the impact of the 6-month intervening period. See, Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020.

[162] Deloitte Access Economics, *Wage Price Index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020.

[163] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 17.

[164] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 17.

[165] Economic Insights, *Memorandum prepared for the AER on review of econometric models used by the AER to estimate output growth*, 18 May 2020, p. 8.

Jemena proposed 59.7 per cent for labour and 40.3 per cent for non-labour inputs.[166]

Consequently, the key differences between our real price growth forecasts and Jemena's are that:

- we only used labour price growth WPI forecasts from Deloitte, rather than the average of forecasts from Deloitte and BIS Oxford Economics
- we used updated input price weights.

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

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 Jemena. This is set out in Table 6.7.

Table 6.7 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	1.6	1.6	1.5	1.5

Source: Deloitte Access Economics, *Wage Price Index forecasts – Report prepared for the Australian Energy Regulator*, 11 August 2020, p. xv; BIS Oxford Economics, *Labour cost escalation forecasts to 2025–26*, October 2019, p. 4.

The BIS Oxford Economics forecasts were prepared prior to COVID–19, which has materially changed the economic outlook. In contrast, Deloitte's forecasts were prepared in late July 2020 and they take into account the effects of the COVID–19.

The difference in the economic outlook underlying the two sets of forecasts is stark. Therefore, 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 labour price growth forecasts for this draft decision. If we have updated BIS Oxford Economics' forecasts that account 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.

[166] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 17.

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

Jemena did not include an additional allowance for the legislated superannuation guarantee increases to its labour price growth forecasts. However, we note that the reset proposals from some other Victorian distribution businesses (CitiPower, Powercor and United Energy) did.[167]

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 that 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.[168] Consequently we have added the legislated superannuation guarantee increases to Deloitte's WPI growth forecasts to forecast labour price growth.[169]

We have applied Deloitte's advice consistently to the five Victorian electricity distribution businesses. Should Jemena provide revised BIS Oxford forecasts with its revised proposal, we would only add the legislated superannuation guarantee increases to them if it is clear that they have been reduced to account for the superannuation guarantee increases.

We also note that the significant economic downturn resulting from COVID–19 has raised the question of whether the superannuation guarantee increases should proceed. We will continue to monitor this situation. If there are any changes to the legislated superannuation guarantee increases we will take that into account in our final decision.

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.

CitiPower, Powercor and United Energy submitted a report from Frontier Economics, which advocated for the use of firm specific 'actual' input weights, rather than the rather

167 For example, Powercor, *Regulatory proposal 2021–2026*, 31 January 2020, pp. 126–127.

168 Deloitte Access Economics, *Impact of changes to the superannuation guarantee on forecast labour price growth*, 24 July 2020, p. 4.

169 Deloitte Access Economics, *Impact of changes to the superannuation guarantee on forecast labour price growth*, 24 July 2020, pp. 4-5.

than the industry–wide weights we use.[170] We engaged Economic Insights to consider the issues raised by Frontier Economics.[171] Economic Insights recommended that we maintain our existing approach of using an industry average. 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. Our response to Frontier Economics is discussed in more detail in our draft determination for CitiPower, Powercor and United Energy (Attachment 6).

In contrast, Jemena proposed input price weights of 59.7 per cent for labour and 40.3 per cent for non-labour.[172]

6.4.4.2 Forecast output growth

We have included forecast average annual output growth of 1.0 per cent in our alternative opex estimate. This compares to Jemena's proposed average annual output growth of 1.3 per cent.[173] This increases our alternative estimate of total opex by $11.6 million ($2020–21), instead of $23.2 million ($2020–21) as proposed by Jemena.

We and Jemena have forecast output growth by:

- forecasting the growth rates for four outputs (customer numbers, circuit line length, energy throughput, and maximum demand)
- calculating five weighted average overall output growth rates using the output weights from our five benchmarking models presented (see Table 6.8)
- averaging the five benchmarking model specific weighted overall output growth rates.

Table 6.8 Output weights, per cent

	Cobb-Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA	Opex MPFP	Average	Jemena proposed
Customer numbers	67.4	69.0	38.0	69.7	18.5	52.5	58.0
Circuit length	15.1	15.6	21.2	12.4	39.1	20.7	18.0

170 Frontier Economics, *Estimation of opex input weights, Report prepared for CitiPower, Powercor and United Energy*, 15 March 2019.

171 Economic Insights, *Memorandum prepared for the AER on review of econometric models used by the AER to estimate output growth*, 18 May 2020.

172 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure,* 24 February 2020, p. 17.

173 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, p. 21; Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020.

	Cobb-Douglas SFA	Cobb Douglas LSE	Translog LSE	Translog SFA	Opex MPFP	Average	Jemena proposed
Ratcheted maximum demand	17.5	15.5	40.9	17.9	33.8	25.1	21.6
Energy throughput	–	–	–	–	8.6	1.7	2.4

Source: Economic Insights, *Memorandum prepared for the AER on review of econometric models used by the AER to estimate output growth*, 18 May 2020, p. 21; Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020.

Notes: Numbers may not add up to 100 per cent due to rounding.

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 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.

Our output weights are different from those proposed Jemena. This is because, consistent with the other Victorian resets, in response to issues raised by CitiPower, Powercor and United Energy we have updated the output weights in the opex MPFP model to correct for a coding error identified and changed our approach for the translog models. These issues are discussed below.

The opex MPFP output weight

As part of their initial proposals, CitiPower, Powercor and United Energy submitted a Frontier Economics report that raised concerns about statistical problems with the opex MPFP model and identified a coding error in the calculations.[174]

Our consultant, Economic Insights has reviewed Frontier Economics' report and agreed there was a coding error in the calculations. Economic Insights found correcting this error significantly improves the performance of the opex MPFP model and consequently mitigates the other concerns raised by Frontier Economics about the opex MPFP model.[175] Consequently, Economic Insights considered we should include the MPFP weights when we forecast output growth.[176] 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. Our response to Frontier Economics is discussed in more detail in our draft determination for CitiPower, Powercor and United Energy (Attachment 6).

174 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.

175 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.

176 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.

The effect of correcting the error on the output cost weights is shown in Table 6.9. 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 6.9 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
Circuit length	28.99	39.14

Source: Economic Insights, *Memorandum prepared for the AER on review of econometric models used by the AER to estimate output growth*, 18 May 2020, p. 16.

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 distribution businesses in the international sample. However, CitiPower, Powercor and United Energy stated that, instead, the elasticities should be evaluated at output levels that reflect the operating characteristics of the Australian distributors.[177] Frontier Economics in its report for CitiPower, Powercor and United Energy 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, CitiPower, Powercor and United Energy did not use the translog models to derive their proposed output weights.

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.[178]

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.[179] It demonstrated that there is economic justification for using both bases and the statistical performance of the models using either basis is similar.[180]

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177 Powercor, *Regulatory proposal 2021–2026*, 31 January 2020, p. 130.

178 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.

179 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.

180 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.

Calculating the translog opex cost function output weights at Australian average output levels addresses the concerns raised by Frontier Economics.[181] Accordingly, we consider those weights should be included in our calculation of forecast output growth.

Table 6.10 below presents 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 is to transfer weight from customer numbers to line length and ratcheted maximum demand.[182]

Table 6.10 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 prepared for the AER on review of econometric models used by the AER to estimate output growth*, 18 May 2020, p. 19-20.

Forecast growth of the individual output measures

In developing our alternative estimate we have used Jemena's circuit length forecasts for the next regulatory control period. However, we are not satisfied that its forecast of the growth in customer numbers, ratcheted maximum demand and energy throughput reasonably reflect a realistic expectation. Specifically, for:

- **customer numbers:** we have adjusted Jemena's pre-COVID–19 forecasts in line with the reduction we applied to customer connections, using the Housing Industry Association's April 2020 dwelling starts forecasts.[183]
- **ratcheted maximum demand:** we have forecast ratcheted maximum demand based on AEMO's 2019 maximum demand forecasts at the transmission connection point to forecast maximum demand. AEMO is not forecasting demand

181 For our discussion on the concerns raised by Frontier Economics, see AER, *Draft decision - Powercor distribution determination 2021–26 - Attachment 6*, September 2020.

182 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.

183 AER, *Draft decision - Jemena Distribution determination 2021–22 to 2025–26 - Attachment 5 Capital expenditure*, September 2020, pp. 29-30.

to surpass 2019, suggesting no growth in ratcheted maximum demand. In contrast Jemena forecast growth from 2022–23.[184] We discuss this further in Attachment 5.

- **energy throughput:** we have forecast energy throughput based on Jemena's historic average growth rate to forecast energy throughput. Over the period 2006–18, actual energy throughput growth has averaged –0.2 per cent per year. Further, AEMO's forecast of energy throughput at the state level in its *2019 Electricity Statement of Opportunities* is no more than the historic average. In contrast to our forecast, Jemena's forecast energy throughput of around 1.0 per cent per year.

Our output growth forecasts are set out our opex model for this draft decision.

6.4.4.3 Forecast productivity growth

We have forecast productivity growth of 0.5 per cent per year in developing our alternative opex forecast. Jemena also included forecast productivity growth of 0.5 per cent per year in its opex forecast.[185] This reduces our alternative estimate of opex over the 2021–26 regulatory control period by $5.8 million ($2020–21), which is slightly lower than Jemena proposed ($7.4 million ($2020–21)) as our alternative estimate has a lower base opex.

6.4.4.4 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 (which is outside the 2021–26 regulatory control period).

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 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.

Jemena agreed to this amendment.[186]

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 Assessment Guideline, we will include a step change if the

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184 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 21.

185 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 22.

186 Jemena, *Information request 037,* 25 June 2020, p. 1.

efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost for such items.[187]

Jemena proposed seven step changes totalling $42.4 million ($2020–21) or 7.4 per cent of its proposed total opex forecast.[188] These are shown in Table 6.11 along with our draft decision, which is to include step changes totalling $32.4 million ($2020–21) in our alternative estimate.

Table 6.11 Jemena proposed step changes and our draft decision ($ million, 2020–21)

Step change	Jemena proposed step changes	AER draft decision	Difference
Bushfire insurance premium	28.8	28.2	-0.6
REFCL testing and maintenance	1.3	1.3	-
Future grid program	3.8	0	-3.8
Transitional return on debt alignment	0.9	0	-0.9
EPA regulations	4.2	0	-4.2
Cyber security	2.9	2.9	0
Additional RIN reporting	0.5	0	-0.5
Total	42.4	32.4	-10.0

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure*, 24 February 2020, pp. 23-24. Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26,* 25 February 2020; AER analysis.

Note: The transitional return on debt alignment step change was withdrawn by Jemena.

The following sections set out the reasons for our draft decision, including the alternative estimates we have developed.

6.4.5.1 Bushfire insurance premium

Jemena proposed a $28.8 million ($2020–21) step change for rising bushfire insurance premiums over the 2021–26 regulatory control period.[189] We have assessed this step change and are satisfied that it is prudent and efficient given its materiality and that it is likely the increasing costs are not captured through our non-labour price growth forecast or would reasonably be offset by decreases in other cost categories over the

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

[188] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06-01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, pp. 23-24.

[189] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 23.

2021–26 regulatory control period. We have included this step change in our alternative estimate with a small update to reflect current inflation forecasts.[190]

Table 6.12 Bushfire insurance premium step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal	3.9	5.1	6.1	6.6	7.1	28.8
AER draft decision	3.9	5.0	6.0	6.4	6.9	28.2
Difference	0.0	-0.1	-0.1	-0.1	-0.1	-0.6

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020; AER analysis.

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

Jemena's proposed step change reflects its brokers' advice (AON Report) that it considers that there will be a material and sustained increase in its bushfire liability insurance over the 2021–26 period. The main reasons it included in support of this step change were:

- Higher costs are necessary to maintain adequate and appropriate bushfire liability insurance.
- Such costs are beyond Jemena's control and are not reflected in the base or captured through price growth.
- Such costs are prudent and efficient and Jemena is entitled to recover these costs.
- Self-insurance is not a suitable approach for this type of exposure and should only be used for risks that are relatively minor and frequent.[191]

Existing insurance costs are a part of the base opex and the rate of change provides an allowance to take into account forecast growth in input prices and of particular relevance to insurance, non-labour price growth. Therefore, even if there are some short term increases in insurance costs, there are built-in mechanisms in the framework that address these higher opex costs.

However, we also recognise that there may be specific circumstances where it is appropriate to consider increasing costs of individual cost categories. In particular where a cost category represent a material proportion of opex and the cost increases are likely to be higher than what is allowed for within the rate of change or would reasonably be offset by decreases in other cost categories over the 2021–26 regulatory control period. For example, our final determination for Directlink allowed for

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[190] Reserve Bank of Australia, *Statement of Monetary Policy-Appendix: Forecast*, August 2020.

[191] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 6.

higher insurance premiums as a category specific forecast.[192] In that case, Directlink's insurance costs were on average 12 per cent of its total opex forecast.

We consider that Jemena's bushfire insurance premium step change, representing 5.0 per cent of total opex, falls within the range of being a material proportion of opex. Further, that the circumstances that Jemena faces in the insurance liability market for one of its cost inputs are sufficiently exceptional that it would materially change its total opex over time beyond what is captured through our non-labour price growth forecast.

To understand this, we engaged expert consultants to assist us in assessing the magnitude of Jemena's proposed higher bushfire insurance premiums.[193] The expert consultants' broadly agreed with the views of Jemena's insurance brokers about the future trends and magnitude of increases in insurance premium increases over the next regulatory control period.

In arriving at our draft decision, we have taken into account stakeholders submissions outlined in section 6.2.1. The CCP17 commented that any reasonable materiality threshold would almost certainly be exceeded based on Jemena's proposal and therefore it accepted this as a step change.[194] The CCP17 also noted that the forecast should be reviewed in the revised proposal by which time businesses will have more information from their insurance brokers.[195] Other submissions noted the material nature of the step change proposed by Jemena and encouraged the AER to undertake further investigation to ensure only efficient costs are allowed.[196] We believe that our decision to include the insurance step change in our alternative estimate takes into account and addresses the issues raised in the submissions.

Given the volatility of the insurance liability market, we expect Jemena to provide updated information (relating to its 30 September 2020 insurance premium renewal) in its revised proposal which will inform our final decision.

6.4.5.2 Rapid Earth Current Fault Limiters

Jemena proposed a $1.3 million ($2020–21) step change for its REFCL testing and maintenance obligations.[197] We are satisfied that Jemena will need to meet new REFCL testing and maintenance requirements in the next regulatory control period. For this draft decision we have included its proposed step change of $1.3 million ($2020–21) in our alternative estimate. However, we note this is subject to change and

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[192] AER, *Draft decision - Directlink Transmission Determination 2020–25, Attachment 6, Operating expenditure,* October 2019, pp. 16-19.

[193] Taylor Fry and Wills Re, *Australian Energy Regulatory Jemena Bushfire Liability Insurance,* 14 July 2020.

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

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

[196] Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, p. 68.

[197] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 23.

expect Jemena to provide an updated estimate in its revised proposal that reflects the impact of any ESV exemption on its testing and maintenance obligations, as well as changes in forecast inflation.

Table 6.13 REFCL step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal and AER draft decision	0.0	0.1	0.4	0.4	0.4	**1.3**

Source: Jemena, *2021–26 26 Electricity Distribution Price Review Regulatory Proposal Attachment 06–05 - Operating expenditure step changes,* 24 February 20, pp. 7–10; AER analysis.

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

The *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016*[198] require Victorian distributors (AusNet Services, Powercor and Jemena) to:

- install REFCLs at 45 designated zone substations following a prescribed and tiered process (Tranche 1 by 1 May 2019, Tranche 2 by 1 May 2021 and Tranche 3 by 1 May 2023)
- undertake REFCL testing before the commencement of each specified bushfire risk period to ensure that lines originating from each prescribed zone substations continue to meet the required capacity.

These obligations require Jemena to install one REFCL device at Coolaroo Zone Substation by 30 June 2023.[199] However, after submitting its initial proposal Jemena notified us of its application to ESV for an exemption, which if granted, would allow Jemena to undertake an alternative installation program at a different zone-substation. According to Jemena, "the outcome of this exemption process will determine matters such as the number of REFCL-protected feeders which would exist".[200]

We are satisfied that this step change reflects new obligations to annually test REFCL devices once they are installed as required by the *Electricity Safety (Bushfire Mitigation) Regulations 2016*.

We have received four submissions relating to Victorian distributors' REFCL proposals. In general, stakeholders expected us to scrutinize the efficiency of the proposed amounts and take into account the impact of any exemption that the network service

198 *Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 (VIC)* see https://content.legislation.vic.gov.au/sites/default/files/29fcbe85-2f8a-3b84-8b52-bb1b9cd9f395_16-032sra%20authorised.pdf

199 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 7.

200 Jemena, *Information request 030*, 12 June 2020, p. 5.

providers may obtain from ESV.[201] The VCO considered that Powercor's proposal is relatively high and requested that we investigate the differential between Powercor and AusNet Services and Jemena.[202]

We have taken these submissions into account in forming our decision. Specifically, we requested clarification on the timing of the potential outcome of Jemena's application for exemption relating to its Coolaroo zone-substation. In response, Jemena advised it anticipates ESV's decision is likely to be submitted to the Department of Environment, Land, Water and Planning around early August 2020 for the Minister's consideration.[203] We expect Jemena to include the results of this application and any updates to its step change in its revised proposal and we will assess the efficiency of its revised proposal in making our final decision.

6.4.5.3 Future Grid

Jemena proposed a step change totalling $3.8 million ($2020–21) to prepare its network for the increased penetration of distributed energy resources (DER). The step change is part of Jemena's Future Grid program to futureproof its network through implementation of 'least regret' initiatives to respond to changes in the energy market over the next decades, particularly as customer uptake of DER continues to accelerate.[204] Jemena also proposed $23.6 million ($2020–21) capex[205] for the Future Grid program. This step change covers the costs of undertaking activities to increase hosting capacity by modifying customers’ DER inverter settings, inspect the low voltage network assets and enable DER portfolio preparatory work packages.[206] We have not included this step change in our alternative estimate for the reasons outlined below.

Table 6.14 Future Grid step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena’s proposal	0.75	0.75	0.75	0.76	0.76	**3.8**
AER draft decision	0	0	0	0	0	**0**

201 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, pp. 65-66; Energy Consumers Australia, *Victorian Electricity Distributors Regulatory Proposals 2021–26,* June 2020, Attachment 1, p. 4; Energy Safe Victoria, *Submission on the Victorian Electricity Distribution Regulatory Proposal 2021–26*, May 2020, p. 1; CCP17, *Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021–26*, 10 June 2020, p. 55.

202 Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, pp. 65-66.

203 Jemena, *Information request 030*, 12 June 2020 and follow up email, 16 July 2020.

204 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 11.

205 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 05–01 Forecast capital expenditure report - Public,* 31 January 2020*,* p. 94. This is considered in Attachment 5.

206 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 12.

Difference	-0.75	-0.75	-0.75	-0.76	-0.76	**-3.8**

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–04 SCS Opex Model FY22–26 - Public,* 25 February 2020, AER analysis.

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

Jemena's proposed Future Grid step change seeks to ensure new photovoltaic (PV) systems installed on its network will not be constrained and comprises the following: [207]

- $0.8 million ($2020–21) to cover an additional full-time asset inspector to gather low voltage (LV) network data, to feed into LV network modelling. The expansion of Jemena's LV network modelling capabilities will improve its visibility and understanding of its DER network hosting capacity, to enable it to streamline and facilitate the connection of new DER systems, through implementation of a DER website.[208]
- $1.2 million ($2020–21) in 2021–22 to cover information technology (IT) operational technology enhancements as part of the preparatory work package. Jemena submits this work is required prior to capital works to increase network hosting capacity and includes activities to establish methods, processes and explore options of the investment. Examples include developing the data architecture for the LV network model and developing a method to assess hosting capacity of various network assets.[209]
- $1.8 million ($2020–21) over the next regulatory control period to cover payments of $500 to 700 customers per year to incentivise them to engage a qualified person to modify their inverter settings in order to enable voltage regulation of 35 000 old inverters.[210] Jemena submits that in some cases, this will have a materially positive impact on addressing localised power quality issues, which can cause inverters to trip off.[211]

Jemena submits the Future Grid program is aligned to its People's Panel[212] recommendation that Jemena should enable increased feed-in of PV generation into the grid.[213] None of the People’s Panel members supported option 1 ‘restrict exporting

207 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 05–04 - Future Grid investment proposal - Public,* 31 January 2020, p. 24.

208 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 05–04 - Future Grid investment proposal - Public,* 31 January 2020, pp. B1, B2.

209 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 14.

210 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, pp. 14-15.

211 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, pp. 14-15.

212 Jemena undertook their People’s Panel process, which involved a series of customer engagement sessions with a group of 43 people representatives of Jemena’s residential customer base.

213 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 05–04 - Future Grid investment proposal - Public,* 31 January 2020, p. 24.

in some areas'; 15 per cent supported option 2 'keep increasing the grid's capacity to match demand'; and 85 per cent supported option 3 'improve the Grid's performance through new technology'.[214] Jemena submitted its small business customers had similar views.[215] Jemena noted at the time of this customer engagement, the costs of the initiatives were presented.[216] We consider there has been limited customer testing of the compliance program and the initiative to establish systems and processes to support DER related work. The material provided by Jemena shows that the LV network modelling initiative was the only option tested through customer engagement.[217]

In our assessment, we considered whether the proposed expenditure for the activities is prudent and efficient. We engaged expert consultants, EMCa, to assist us with this assessment.

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 forecast would typically provide adequate compensation to a prudent operator for operating and maintaining a network. However we have previously acknowledged output growth may not fully account for growing DER and in that case it would be appropriate to allow a step change for DER management.[218] Thus, we consider there is a legitimate step change driver in this instance, as Jemena is seeking to manage the increased uptake of DER, primarily solar, on its network.

While we consider there is a legitimate driver for a step change to cover higher opex as a result of DER management related activities, we have not included the step change for the future grid program in our alternative estimate. We consider Jemena has not sufficiently justified the need for additional opex for the initiatives, some of which are managed as part of their business-as-usual activities. EMCa's assessment concluded while Jemena's requirement for some additional LV network information is reasonable, Jemena has not provided compelling evidence to support the need for an extra inspector.[219] EMCa also found the $1.2 million ($2020–21) preparatory work program consisted of one-off activities, which could be capitalised as part of the Future Grid capex program, and concluded Jemena did not provide compelling evidence it had explored other credible alternatives to deliver the work.[220]

We also do not consider the proposed $1.8 million ($2020–21) for the inverter program has been demonstrated to be efficient. Jemena has not provided any evidence or

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214 Jemena, *Information request 020*, 27 May 2020, p. 2.

215 Jemena, *Information request 020*, 27 May 2020, p. 2.

216 Jemena, *Information request 020*, 27 May 2020, p. 2.

217 Jemena, *Information request 020,* 27 May 2020, Attachment A, Attachment B, Attachment C.

218 AER, *Draft decision, South Australia Power Networks distribution determination 2020–2025, Attachment 6: Operating Expenditure*, October 2019, pp. 34-35.

219 EMCa, *Jemena regulatory proposal 2021–26: Review of proposed future grid and cyber security opex step changes*, August 2020, p. 6.

220 EMCa, *Jemena regulatory proposal 2021–26: Review of proposed future grid and cyber security opex step changes*, August 2020, pp. 6-7.

analysis that indicates the effectiveness of the $500 incentive payments to households with inverter systems to modify their settings to ensure they are compliant. EMCa advised while modifying inverter settings is likely to improve hosting capacity, it had concerns regarding the incentive payment. In particular, that the cost of the incentive scheme would effectively be a wealth transfer to those customers with inverters and in the absence of the $500 incentive payments there are clear advantages to those customers to change their settings to maximise their individual PV system export capacity.[221] In addition, EMCA noted there are other options to the proposed scheme, including a reset of the inverter settings as part of a service call at little or no incremental costs to the relevant customer.

We note that the capex component of the Future Grid initiative is accepted as a part of our draft decision. See attachment 5 for the related capex assessment.

6.4.5.4 Transitional return on debt alignment costs

Jemena proposed a step change totalling $0.9 million (2020–21) to cover hedging costs for its return on debt, incurred as a result of the move from calendar year to financial regulatory years by the Victorian Government. Subsequent to its initial proposal Jemena withdrew this step change. Given this, we have not include this step change in our alternative estimate. This is reflected in Table 6.15.

Table 6.15 Transitional return on debt alignment cost step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal	0.1	0.1	0.2	0.2	0.3	**0.9**
AER draft decision	0	0	0	0	0	**0.0**
Difference	-0.1	-0.1	-0.2	-0.2	-0.3	**-0.9**

Source: Jemena, *2021–26* Electricity *Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 20, pp. 16-18; AER analysis.

6.4.5.5 Environment Protection Amendment Act 2018

Jemena proposed a step change of $4.1 million ($2020–21) to comply with its new obligations under the *Environment Protection Amendment Act 2018* (*2018 Amending Act*). The changes under the *Amending Act 2018* include specific elements around the General environment duty (GED), duties to notify the Environment Protection Authority Victoria (EPA Victoria) of pollution incidents, permissions, duties for contaminated land

221 EMCa, *Jemena regulatory proposal 2021–26: Review of proposed future grid and cyber security opex step changes*, August 2020, p. 7.

and enforcement powers for EPA Victoria.[222] We have not included this step change in our alternative estimate. While we are satisfied that the *2018 Amending Act* represents a change to Jemena's regulatory obligations, we are not convinced that Jemena's proposed response to these new obligations is efficient.

Table 6.16 EPA step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal	0.8	0.8	0.8	0.8	0.8	**4.2**
AER draft decision	0	0	0	0	0	**0**
Difference	-0.8	-0.8	-0.8	-0.8	-0.8	**-4.2**

Source: Jemena, *2021–26 26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes,* 24 February 20, pp. 19-21; AER analysis.

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

Under the *2018 Amending Act*, Jemena considered that the introduction of the GED, and the specific obligations relating to land contamination are the main drivers of additional operational activities and expenditure over the 2021–26 regulatory control period.[223] Accordingly, it proposed the following activities to comply with the *2018 Amending Act*:[224]

- a desktop study to assess and quantify Jemena's environmental risk profile, including identification of sites requiring investigation
- site environmental risk assessments of five zone substation or depot ('large') sites per annum
- site environmental risk assessments of 20 distribution asset sites (predominately a sample of distribution substations) per annum
- the production of a specific Environmental Management Plan for each large site (30) and common Environmental Management Plans for different asset types (20)
- the ongoing annual monitoring of sites identified through risk assessments as posing an elevated risk
- one internal full-time equivalent resource to manage the above activities on an ongoing basis, including increased liaison with EPA Victoria.

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222 Department of Environment, Water, Land and Planning Victoria, *Environment Protection Amendment Act 2018 – Fact Sheet*.

223 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 19.

224 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, pp. 20-21.

After Jemena submitted its initial proposal, the Victorian Government delayed the commencement of the *2018 Amending Act* by one year to July 2021.[225] Despite this, Jemena considers that it has reasonable certainty as to whether it will need to comply with the GED, its duties to notify EPA Victoria of pollution incidents and its duties relating to contaminated land.[226]

The new GED, which is the cornerstone of the *2018 Amending Act*, establishes a proactive regulatory approach to preventing waste and pollution impacts, rather than managing the impacts after they occur.[227] It requires the identification, assessment and control of risks, whether or not actual harm occurs.

We understand that the GED puts the onus of determining the appropriate risk-management control on the regulated entity and is not prescriptive about what activities may be required in order to discharge the obligation. The *2018 Amending Act's* Fact sheet states that the GED aligns with the way many businesses and industries already manage risk […] Its concept is familiar to businesses through the well-established model of protection provided by Victoria's Occupational Health and Safety laws, which are also centred around a general duty to take reasonably practicable measures to reduce the risk of harm.[228]

We are satisfied that the *2018 Amending Act* represents a change to Jemena's regulatory obligations (noting the change in the timing for implementation). However, we are not convinced that Jemena's proposed response to the *2018 Amending Act* is efficient. We have examined the activities Jemena proposed to undertake and the associated cost estimates. We are concerned some of Jemena's assumptions regarding the proposed environmental risk assessment of zone substations and depots (large and small sites) are unrealistic. For example, Jemena has proposed to undertake a significant amount of what we consider quite costly and relatively extensive groundwater testing and comprehensive soil testing at almost all sites.[229] We do not consider such extensive testing is required and note this does not appear to be reflected in the Regulatory Information Statement for the *2018 Amending Act* obligations.

Consequently, we have not included this step change in our alternative estimate of total forecast opex. However, Jemena may wish to provide in its revised proposal further information to support its proposed approach. For example, this could include an independent expert opinion to validate its claims the *2018 Amending Act* reasonably

225 As a result, CitiPower, Powercor and United Energy withdrew elements of their proposals relating to the compliance with the 2018 Amending Act.

226 Jemena, *Information request 023*, 3 June 2020, p. 2.

227 Department of Environment, Water, Land and Planning Victoria, *Environment Protection Amendment Act 2018 – Fact Sheet*, p. 1.

228 Department of Environment, Water, Land and Planning Victoria, *Environment Protection Amendment Act 2018 – Fact Sheet*, p. 1.

229 Jemena, *Information request 047*, 21 July 2020, p. 1; Jemena, *Information request 023*, 3 June 2020.

extends to extensive groundwater testing and comprehensive soil testing for zone substation sites and depot site.

6.4.5.6 Cyber security

Jemena proposed a $2.9 million ($2020–21) step change to undertake work to lift its current capability to detect and respond to cyber security incidents to meet standards set for distribution businesses by AEMO’s Australian Energy Sector Cyber Security Framework (AESCF). We have included this step change in our alternative estimate as we consider it is prudent and efficient. While we note the AEMO framework is not currently a legislated regulatory obligation, we understand that this likely to occur shortly, and also consider Jemena's response is likely to represent the actions of a prudent operator in the current context of escalating cyber security threats.

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

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena’s proposal	0.6	0.6	0.6	0.6	0.6	**2.9**
AER draft decision	0.6	0.6	0.6	0.6	0.6	**2.9**
Difference	0	0	0	0	0	**0**

Source: Jemena, *2021–26* Electricity *Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 20, p. 23; AER analysis.

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

In its initial proposal Jemena submitted that its current cyber security measures do not meet increased customer, governmental and community expectations of IT security protections in the context of heightened cybersecurity risks and 'clear guidance from the AEMO'.[230] Further, that it needs to invest in its cyber security efforts in order to keep pace with existing security levels[231] and that it considered meeting the standards set by AEMO's AESCSF[232] for distribution businesses as best practice and prudent.[233]

The AESCSF is a framework developed by AEMO in conjunction with industry and government stakeholders[234] which provides a self-assessment framework for measuring cyber security maturity levels.

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230 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 24.

231 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 20, p. 22.

232 AEMO, AESCSF framework and resources, 2019. Available at https://www.aemo.com.au/initiatives/major-programs/cyber-security/aescsf-framework-and-resources.

233 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 2020, p. 22.

234 Australian Cyber Security Centre (ACSC), Critical Infrastructure Centre (CIC), and the Cyber Security Industry Working Group (CSIWG); the latter includes representatives from Australian energy organisations.

We consulted with AEMO's Chief Security Officer and we understand the exact implementation timing of this legislation remains uncertain, particularly in the current context of COVID–19. In the absence of certainty about the implementation of this legislation and the specific requirements, this is not yet a proven regulatory obligation and is therefore not a compliance obligation. However, we note the current context of evolving threat of cyber security risk, and the Australian Government's recent warning to organisations to take action to mitigate these risks of increased frequency and sophistication of cyber-attacks.[235]

In our assessment we took into account confidential information provided by Jemena related to its self-assessment against the AESCSF's Criticality Assessment Tool.[236] Confidential Appendix D sets out Jemena's self-assessment and cyber security capability gap against the standards set by the AESCSF and the supporting confidential information we have relied on and our assessment.

We engaged expert consultants, EMCa, to assist us with this assessment. In its assessment, EMCa found that Jemena does not currently meet the standards set by the AESCF. EMCa also found Jemena's proposed approach to meet those standards and the quantum of its cyber security program costs to be reasonable.[237]

We have included this step change in our alternative estimate as we while we note the AESCF obligations are not yet formally legislated, we understand that this is likely to occur shortly. In this regard we consider it prudent for Jemena to meet the standards set by the AESCSF for distribution businesses and that its proposed cost to do this are efficient.

6.4.5.7 Additional RIN reporting

Jemena proposed a step change of $0.5 million ($2020–21) for an additional set of RINs it states it will be required to report in the 2021–22 financial year. While the additional cost is driven by incremental change to an existing obligation, given it is relatively immaterial we have not included it in our alternative estimate.

Table 6.18 Additional RIN reporting step change ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal	0.5	0.0	0.0	0.0	0.0	**0.5**
AER draft decision	0.0	0.0	0.0	0.0	0.0	**0.0**
Difference	-0.5	0.0	0.0	0.0	0.0	**-0.5**

235 Prime Minister of Australia, *Statement on malicious cyber activity against Australian networks*, June 2020. Available at https://www.pm.gov.au/media/statement-malicious-cyber-activity-against-australian-networks.

236 For further information, see: https://aemo.com.au/-/media/files/cyber-security/2019/aescsf-cat-overview-2019-v1.pdf?la=en&hash=5EFB6855F99AE6ADF5CBA2C12A3EF0DB.

237 EMCa, *Jemena regulatory proposal 2021–26: Review of proposed future grid and cyber security opex step changes*, August 2020, pp. 11-14.

Source: Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes*, 24 February 20, p. 28; AER analysis.

Jemena noted in its initial proposal that it is currently required to submit a set of RIN responses every twelve months. As a result of the change in timing of the Victorian electricity network regulatory control periods from calendar to financial years, Jemena proposed it will be required to submit an additional set of RIN responses in the 2021–22 financial year to provide information for the six months from 1 January 2021 to 30 June 2021.[238]

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 2020 calendar year
- EB, CA and A RINs for 12 months between 1 July 2020 and 30 June 2021, and
- EB, CA and A RINs for 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 Jemena. 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 will result in some additional one-off costs.

We consider the additional costs to comply with this incremental change are not recurrent and 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 be for the relaxing of some obligations required by ESV in their electric line clearance regulations, which may lead to immaterial reductions in costs. Jemena has not proposed this as a negative step change. We consider the step change framework is not meant to be a bottom up assessment of all changes, and that increases or decreases in immaterial costs should generally cancel each other out.

The points outlined above are consistent with the CCP17's submission, which noted the step change is related to an ongoing obligation and that the costs are not material enough to warrant a step change.[239] The VCO raised similar issues and also

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[238] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–05 - Operating expenditure step changes - Public,* 24 February 20, p. 28.

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

questioned the proposed costs from some distributors as AusNet Services appears to be absorbing the costs.[240]

6.4.6 Category specific forecasts

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

6.4.6.1 Guaranteed service level payments

We have included GSL payments of $0.9 million ($2020–21) in our alternative estimate. This is $0.1 million ($2020–21) more than the $0.8 million forecast ($2020–21) proposed by Jemena.[241]

We have forecast GSL payments as the average of GSL payments made by Jemena between 2015 and 2019. Jemena used the GSL payments it incurred in 2018 only, in its forecast.

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

Jemena stated that one reason it forecast GSL payments based on costs incurred in a single year was because it assumed that its GSL payments were relatively even from year to year.[242] However, we note that its payments over the period 2015 to 2019 have varied from $0.11 million (nominal) in 2015 to $0.25 million (nominal) in 2019. Given GSL payments can be influenced by uncontrollable weather events, we find that they can vary significantly from year to year. Using a five average smooths out these year-to-year, and produces a more reasonable forecast, as well as providing a continuous incentive to minimise GSL payments.

We note the Essential Services Commission (ESC) of Victoria is currently undertaking a review of the consumer protection framework in the Electricity Distribution Code, including the GSL scheme.[243] A draft decision was published on 7 May 2020[244] which sets out proposed changes to the GSL scheme. Consultation on the draft decision

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[240] Victorian Community Organisations, *EDPR 2021–26 Submission to Initial Proposal*, May 2020, p. 67.

[241] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 26.

[242] Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 25.

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

[244] Essential Services Commission, *Electricity Distribution Code review - customer service standards draft decision,* 7 May 2020.

closed on 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 ESC'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.

6.4.6.2 Debt raising costs

We have included debt raising cost of $4.0 million ($2020–21) in our alternative estimate. This is $0.4 million ($2020–21) less than the $4.4 million forecast ($2020–21) proposed by Jemena.[245]

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.

6.4.6.3 Energy Safe Victoria Levy

Jemena proposed to remove the ESV levy from its base opex and proposed it be treated as a category specific forecast. It proposed a category specific forecast of $1.4 million ($2020–21) per year or $6.9 million ($2020–21) over the next regulatory control period.[246] Jemena submitted that it has no control over the cost of the levy and that the levy will increase materially. Jemena stated that if we do not consider this approach appropriate, the levy should be recovered through the B term in the price control mechanism for standard control services, which is consistent with the approach currently employed in Victoria for recovering annual distribution licence fees for the ESC.[247] We have not included the ESV levy as a category specific forecast in our alternative estimate for the reasons set out below.

Table 6.19 ESV levy category specific forecast ($ million, 2020–21)

	2021–22	2022–23	2023–24	2024–25	2025–26	Total
Jemena's proposal	1.4	1.4	1.4	1.4	1.4	**6.9**
AER draft decision	0	0	0	0	0	**0**

245 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 27.

246 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 26.

247 Jemena, *2021–26 Electricity Distribution Price Review Regulatory Proposal - Attachment 06–01 Standard Control Services - Operating Expenditure - Public*, 24 February 2020, p. 26.

Difference	-1.4	-1.4	-1.4	-1.4	-1.4	**-6.9**

Source: Source: Jemena, *2021–26 26 Electricity Distribution Price Review Regulatory Proposal Attachment 06–01 - Standard Control Services - Operating Expenditure - Public,* 24 February 20, p. 26; AER analysis.

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

The ESV levy is used to fund the ESV activities related to regulating the Victorian distribution businesses and is spread across the network operators based on the proportion of customers on each distribution businesses' network.

We are satisfied that there has been an increase in the ESV levy from 2018–19 based on documentation provided by Jemena.[248] However, we have not included this category specific forecast in our alternative estimate as we consider this cost should remain a part of base opex and that increases in the levy can be managed within existing base opex and the forecast rate of change.[249] Base opex already reflects the cost of meeting existing regulatory obligations, and maintaining the reliability, safety and quality of supply of standard control services. This includes ESV levy costs which reflect existing regulatory obligations. In the absence of exceptional circumstances, fluctuations in the ESV levy should be managed within base opex and the forecast rate of change. We acknowledge that some costs may increase by more than the forecast rate of change, however, this is likely offset by other costs that increase by less than the forecast rate of change or by decreases in other cost categories over the 2021–26 regulatory control period.

We do not propose to include a category specific forecast for the ESV levy in our alternative estimate, and we do not propose to remove the ESV levy from the base opex. We consider the ESV levy category specific forecast proposed by Jemena can be managed within its existing base opex and the forecast rate of change.

This approach is consistent with what we are proposing for CitiPower, Powercor and United Energy who have proposed a step change and AusNet who has proposed recovery of the ESV levy through an annual L factor adjustment in the price control formula.

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'.[250]

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:[251]

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248 Jemena, *Information request 024*, 11 June 2020, pp. 1-2.

249 While we have included category specific forecast opex of $0.9 million ($2020–21) in our alternative estimate for GSL payments, we note this reflects our historical treatment. Our preference is to avoid the use of category specific forecast opex to recover expenditure.

250 NER, cl. 6.5.6(e).

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.20 summarises how we have taken the opex factors into account in making our draft decision.

Table 6.20 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the next regulatory control period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred by an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by 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 productivity index number 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 Jemena'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 Jemena's actual past opex with that of other service providers to form a view about whether or not its revealed opex is efficient such that it can be relied on as the basis for forecasting required opex in the forthcoming period.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	This particular factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their proposals, such that they factor in the needs of consumers.[252] Based on the information provided by Jemena in its proposal and CCP17's advice, we consider Jemena consulted with consumers in developing its proposal, noting this was at a relatively high level and generally in relation to total opex. 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 Jemena's proposed step changes. For instance we considered whether the

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

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

Opex factor	Consideration
	proposed step changes represent an efficient capex/opex trade-off. We have had regard to multilateral total factor productivity analysis when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs with respect to the relative prices of capital and operating inputs.
The substitution possibilities between operating and capital expenditure.	As noted above, we considered whether Jemena's proposed step changes represent efficient capex/opex trade-offs. Some of our assessment techniques examine opex in isolation – either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs. We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs. Further, we considered the different capitalisation policies of the service providers' and how this may affect opex performance under benchmarking.
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 Jemena'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 Jemena'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.	Our primary tool assess total opex efficiency, with supporting tools examining the efficiency of both opex and capital inputs as well as at the category level. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of its arrangements with related providers.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our draft decision.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s).	In having regard to this factor, we must identify any regulatory investment test (RIT-D) submitted by the business and ensure the conclusions of the relevant RIT-D are appropriately addressed in the total forecast opex. Jemena did not submit any RIT-D project for its distribution network.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause	We did not identify and notify Jemena of any other opex factor.

Opex factor	Consideration
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
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

A Partial Performance Indicators

The various partial performance indicators (PPIs)[253] we have examined relating to total cost, total opex and the opex cost categories of total overheads and maintenance (which comprise the bulk of Jemena's opex) as well as vegetation management and emergency response are summarised in Table A.1. The results for total costs, total overheads and maintenance are also illustrated in Figure A.1 to A.5.

Table A.1 PPIs of Jemena's historical performance (2014–18 average)

PPI	2014–18 ranking out of 13 distribution businesses	Comments
Total cost per customer[254]	3	Across the different PPI categories, Jemena tends to perform better on the per customer metrics but less well on the per circuit length metrics. This reflects that on a per customer basis an urban business will tend to perform better relative to others in rural areas as it has a shorter and denser distribution of its network per customer. As a result rankings for each of these PPIs present a partial picture of the business performance and must be analysed with caution. Comparisons are generally limited to businesses of a similar customer density or type, unless some relationship between the PPI measure and customer density is known or can be gauged. Where possible, we have plotted PPIs against customer density, to visualise and account for these customer density effects when interpreting the results. See the graphs in figures A.1–A.7.
Total cost per circuit km	11	
Total cost per MW of maximum demand	5	
Total opex per customer	4	
Total opex per circuit km	12	
Total opex per MW of maximum demand	7	
Maintenance opex per customer	1	
Maintenance opex per circuit km	7	
Vegetation management opex per customer	2	
Vegetation management opex per circuit km	7	
Emergency response opex per customer	2	
Emergency response per circuit km	9	
Total overheads per customer[255]	8	
Total overheads per circuit km	12	

253 PPIs can be used to compare the total or category cost performance of businesses in delivering a given type of output. They are a relatively simplistic measure and do not take into account the interrelationships between outputs (or inputs). However, they provide evidence to cross check our economic benchmarking and reflect a more bottom up approach to analysing opex.

254 Total cost include opex and asset costs where the asset costs are annual user cost as the sum of regulatory depreciation and return on investment.

255 Total overheads includes opex and capitalised overheads.

Figure A.1 Total cost (capex and opex) per customer, 2014–18 average ($2020–21)

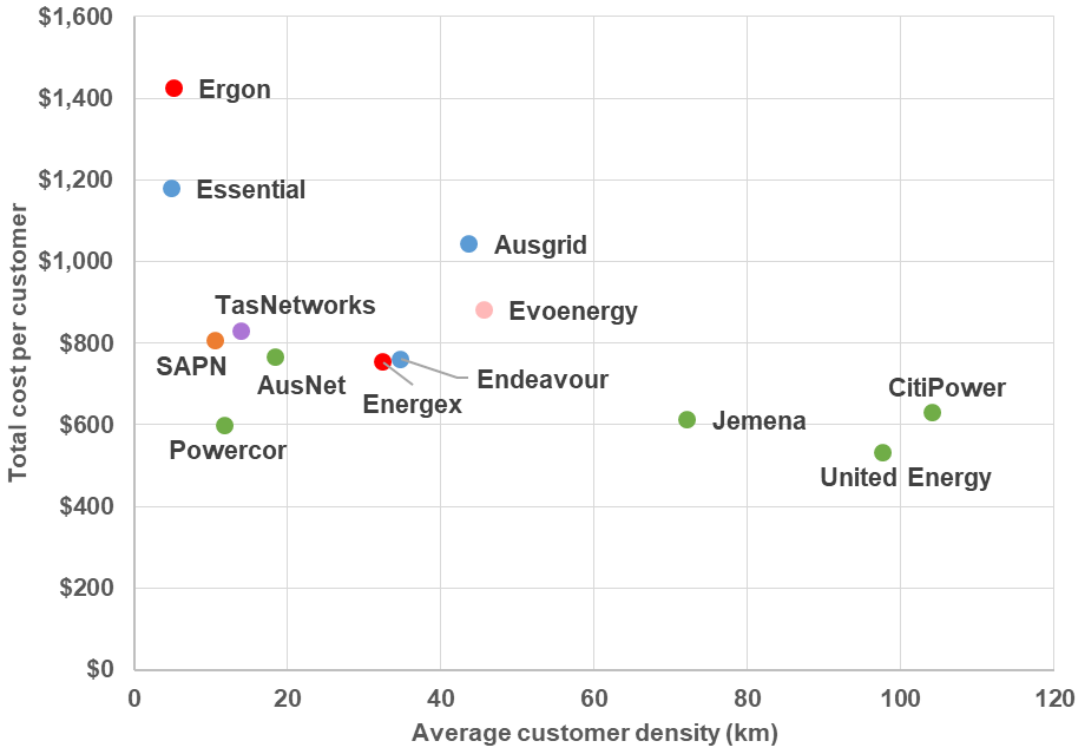


Figure A.2 Total cost (opex and capex) per circuit km, 2014–18 average ($2020–21)

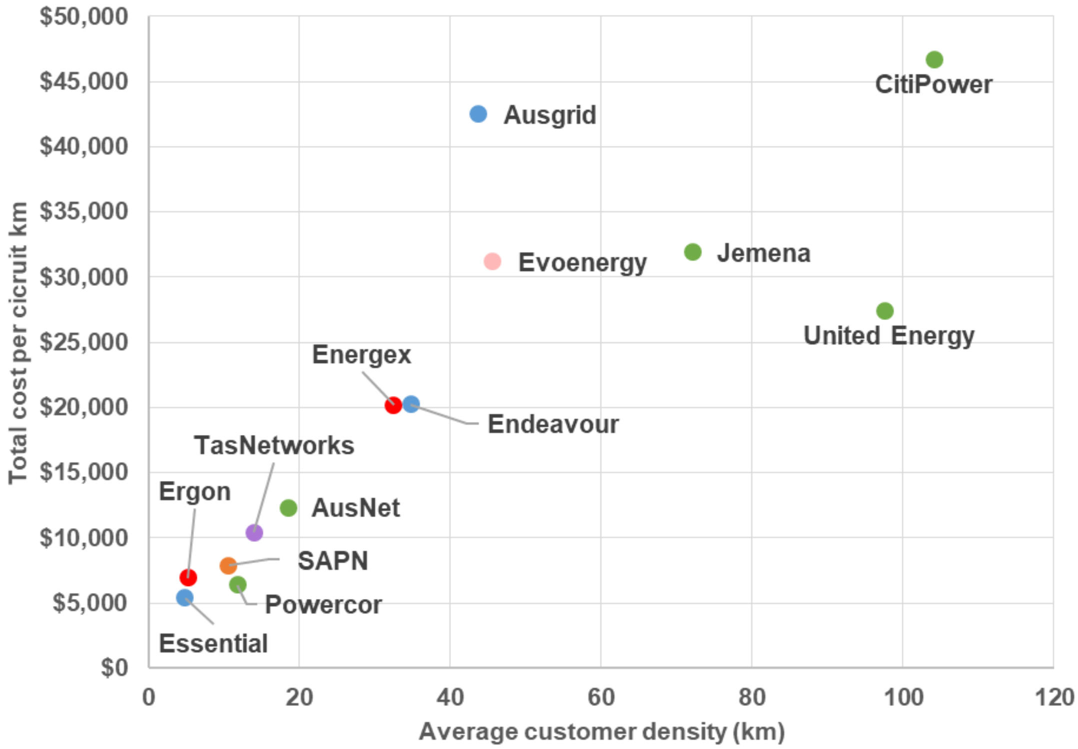


Figure A.3 Total opex per MW of maximum demand, 2014–18 average ($2020–21)

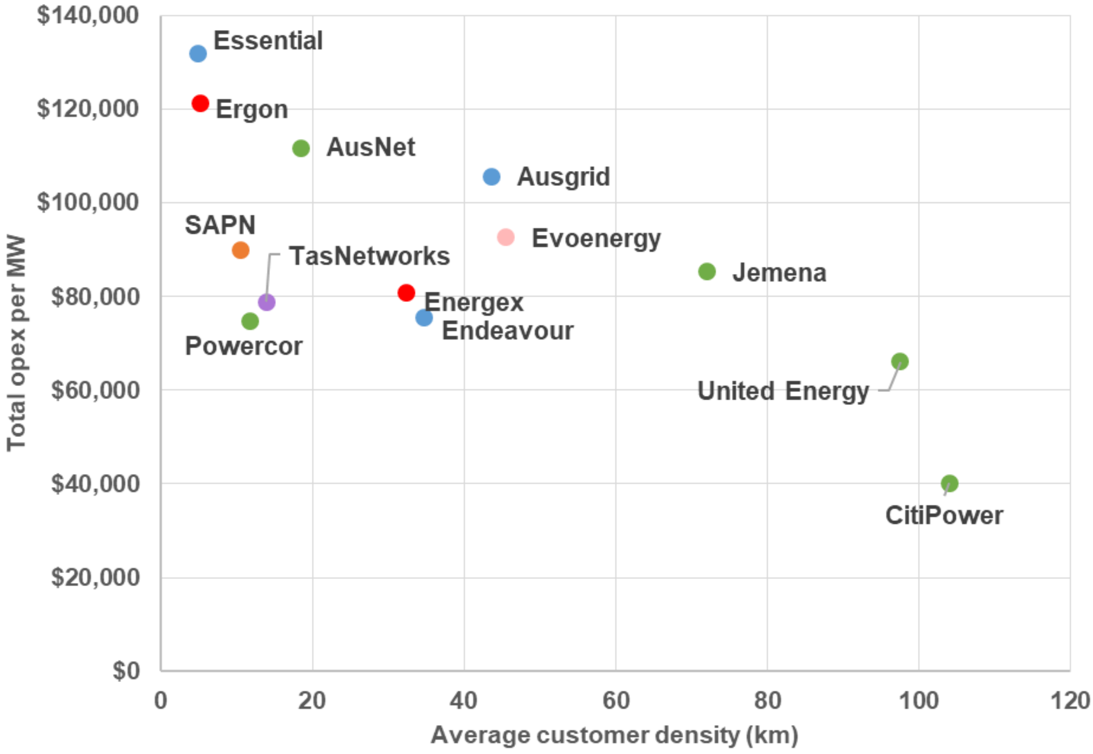


Figure A.4 Maintenance opex per customer, 2014–18 average ($2020–21)

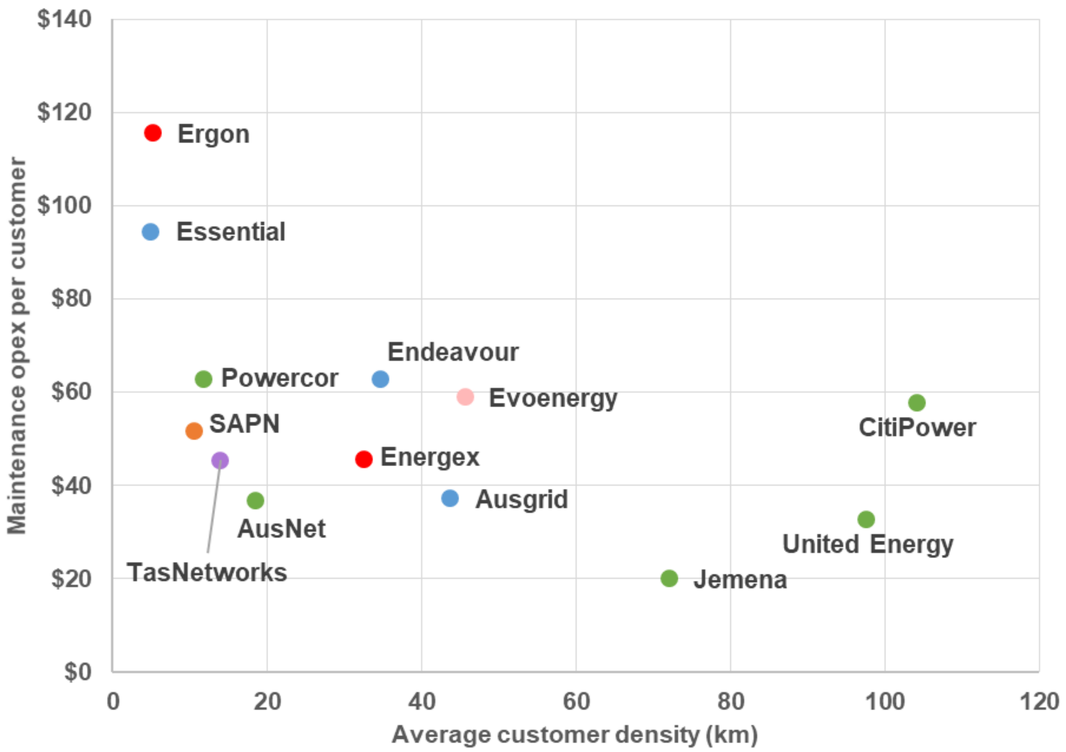


Figure A.5 Maintenance opex per circuit km, 2014–18 average ($2020–21)

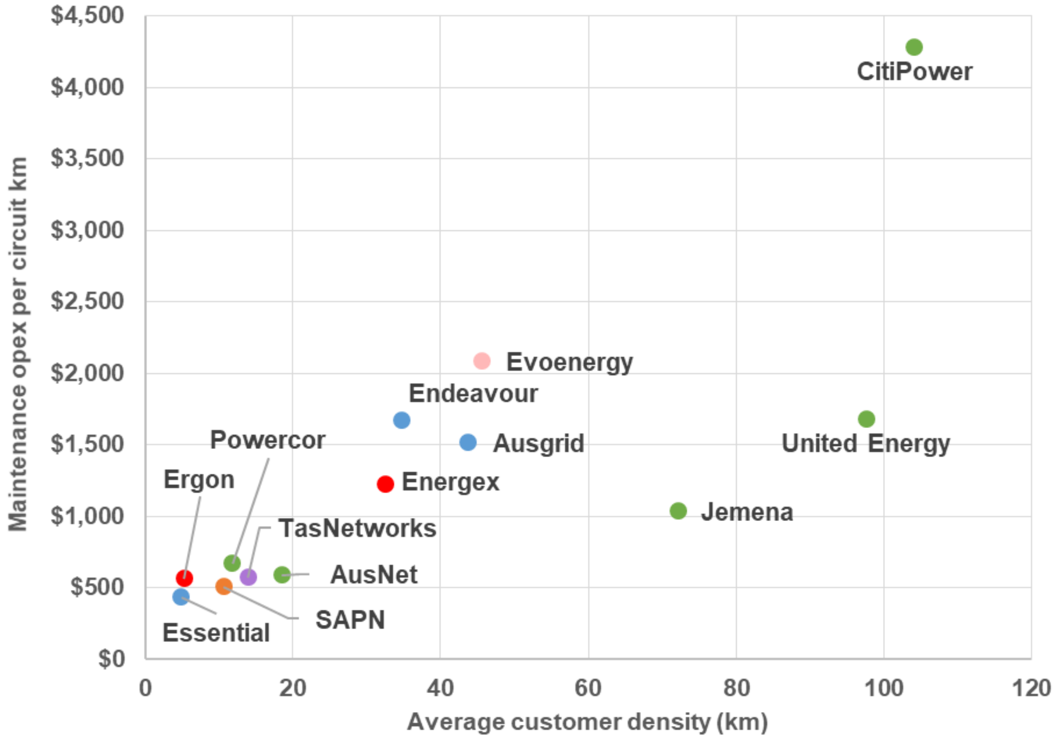


Figure A.6 Total totex overheads per customer, 2014–18 average ($2020–21)

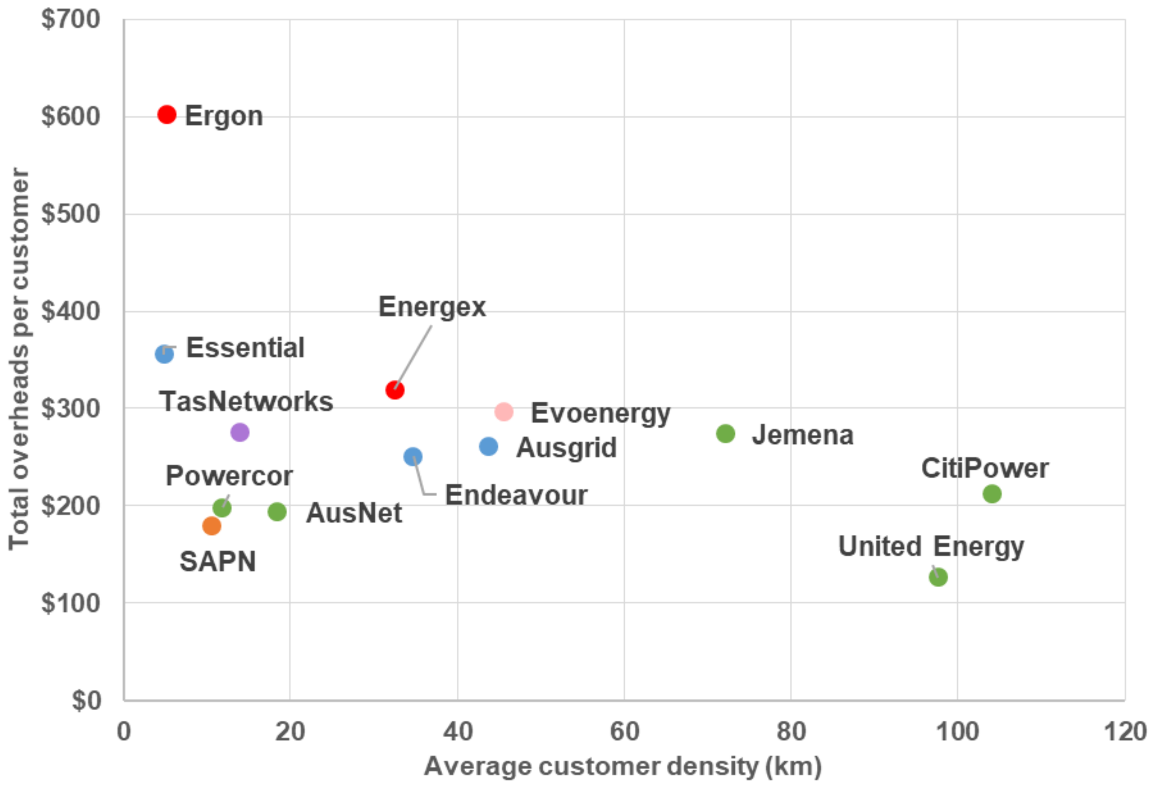


Figure A.7 Total totex overheads per circuit length, 2014–18 average ($2020–21)

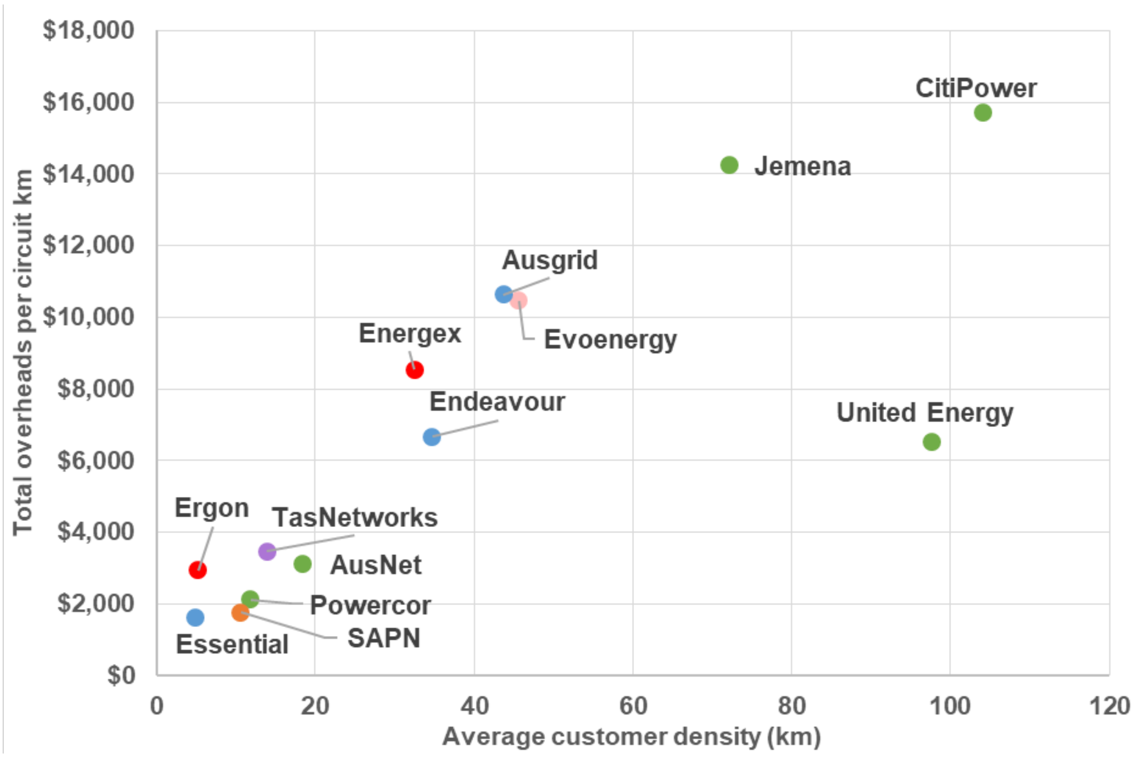


Table A.2 Proportion of cost categories to total opex, 2014–19

Distributor	Maintenance	Vegetation management	Emergency response	Opex overheads	Non-network costs	Balancing item
Evoenergy	19%	5%	4%	66%	12%	-3%
Ausgrid	10%	8%	6%	51%	22%	2%
AusNet	12%	17%	8%	44%	17%	0%
CitiPower	27%	3%	7%	63%	0%	0%
Endeavour Energy	19%	14%	8%	55%	24%	-21%
Energex	15%	11%	11%	57%	34%	-31%
Ergon Energy	19%	10%	11%	57%	24%	-24%
Essential Energy	20%	25%	10%	43%	31%	-30%
Jemena	7%	5%	4%	71%	20%	-5%
Powercor	23%	17%	12%	48%	0%	0%
SA Power Networks	16%	14%	15%	60%	15%	-16%
TasNetworks	15%	19%	15%	60%	21%	-30%
United Energy	16%	11%	10%	54%	5%	4%

Source: Category Analysis RIN responses 2013–14 to 2018–19.

Note: A balancing item is included as a negative, but sometimes positive, item to offset the difference when the cost categories do not sum to total opex. See Appendix B for further discussion.

This analysis excludes confidential information.

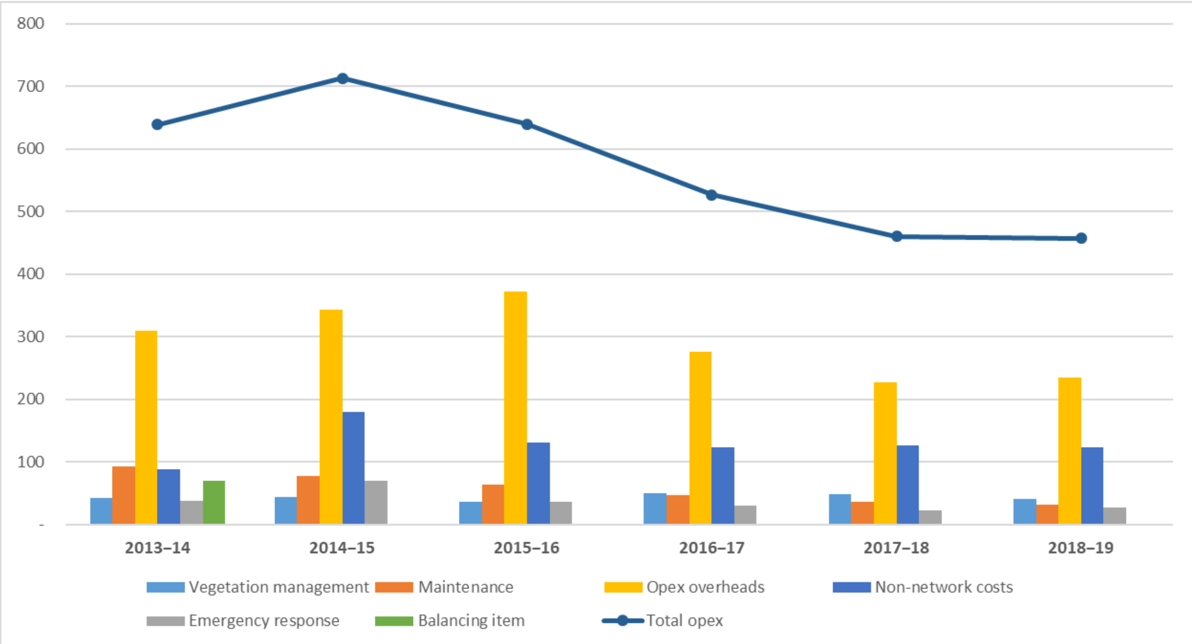
Not all values add up to 100 per cent.

B Cost category analysis

As noted in section Efficiency of Jemena's opex 6.4.1.2, we have compared how Jemena's cost categories have changed over time relative to Ausgrid and Evoenergy. These two distributors have historically performed similarly to Jemena under our top down benchmarking and have customer densities lower than but close to Jemena.

Figure B.1 displays Ausgrid's cost categories over the period 2013–14 to 2018–19. Ausgrid's total opex was 28 per cent lower in 2018–19 compared to 2013–14, which was mainly driven by reductions in opex overheads and maintenance between 2013–14 and 2018–19. All cost categories decreased over this period apart from non-network costs which were higher in 2018–19 than 2013–14. Ausgrid has achieved reductions in total opex over the period by reducing costs for most categories, including opex overheads which is its largest cost category in total opex. In contrast Jemena's opex overheads generally increased over this period, noting the small reduction in 2018, and it has only reduced costs in categories that account for lower proportions of total opex.

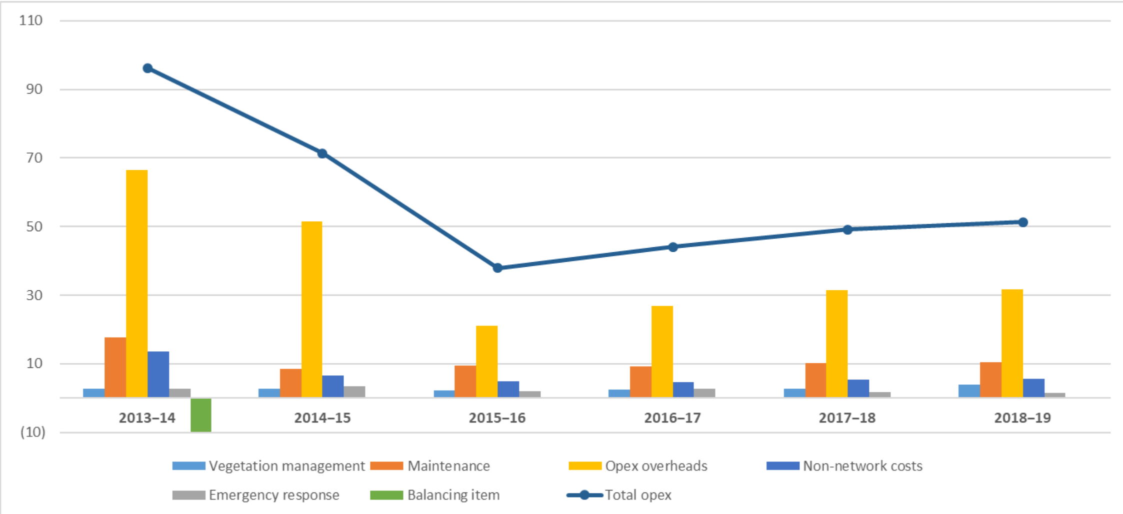
Figure B.1 Ausgrid's opex cost categories over time ($ million, 2020–21)



Source: Ausgrid Category Analysis RIN responses 2013–14 to 2018–19; AER analysis.

Figure B.2 shows Evoenergy's cost categories over the same period. From 2013–14 to 2018–19, Evoenergy achieved reductions in all cost categories other than vegetation management, which is a small component of its total opex. We understand its additional vegetation management costs from July 2018 relate to new obligations. The reduction in total opex was largely driven by a reduction in opex overheads, its largest cost category, and to a lesser extent maintenance and non-network costs. As above, this is in contrast to Jemena's opex overheads which have generally increased over the period, noting the small reduction in 2018. Further, that it has only reduced costs in categories that account for lower proportions of total opex.

Figure B.2 Evoenergy's opex cost categories over time ($ million, 2020–21)



Source: Evoenergy Category Analysis RIN responses 2013–14 to 2018–19; AER analysis.

We note there are limitations with analysing opex category costs sourced from the category analysis RIN. This includes the potential for different cost allocation or accounting approaches. Further, that this data set includes a balancing item (usually negative but sometimes positive item to offset the difference when the sum of other cost categories does not equal total opex). Businesses with a highly negative balancing item are likely to have inflated proportions of total opex for some cost categories. The balancing item varies between businesses and can vary across time which complicates comparisons. In the above analysis the balancing items are not significant in most years. Opex related data items in this dataset is also not scrutinised at the same level as the total opex data supporting our top down benchmarking. Given this, our cost category analysis is used to support top-down benchmarking analysis rather than being relied on to assess base opex on its own.

C Assessment of impact of capitalisation practices on Jemena's opex benchmarking scores

This appendix provides more detail of Jemena's arguments on the impact of capitalisation practices on its opex benchmarking scores and our assessment of these arguments.

C.1 Jemena's submission

Jemena submitted that capex and opex performance should be evaluated together in determining the overall efficiency of a business to take account of any capex/opex trade-offs. Jemena argued that its low opex benchmarking scores are not a reflection of opex inefficiency, but rather that, compared to most businesses, it favours the use of opex over capital inputs.[256]

Jemena further stated "[although] the current benchmarking approach provides incentives for DNSPs to improve cost efficiency, it does not capture these interactions and trade-offs between capex and opex." [257] Jemena further noted that "…results from econometric models should be used with care as they do not reflect capex-opex trade-offs and provide varied efficiency levels." [258]

Jemena explained that, in principle, benchmarking analysis assessed on a total cost basis will account for such trade-offs, enabling distribution businesses to choose the most efficient approach without needing to consider the positive or negative incentives around these choices. Jemena considered that it is overall cost efficient based on its MTFP and total-cost PPI performance and that these measures should have a substantial weight in deciding on an efficient base year. It further submitted that Jemena's opex/capital cost ratio is the highest of the 13 distribution businesses, reflecting that it adopted more operating solutions rather than relying on the flow of capital services to deliver a lower total cost to customers.[259]

C.2 Our assessment

We have considered the impact of capitalisation practices on our opex benchmarking in response to the issues Jemena (and the other Victorian distributors) raised and as part of the continuous improvement of our benchmarking.[260] This is because it could impact the like-with-like comparability of our economic benchmarking. We have also

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256 Jemena, *Information request 043*, 15 July 2020, p. 2.

257 Jemena, *Information request 043*, 15 July 2020, p. 2.

258 Jemena, *Information request 052*, 27 July 2020, p. 6.

259 Jemena, *Information request 043*, 15 July 2020, p. 4.

260 We highlighted this issue in our *2019 Annual Benchmarking Report* as one of our focus areas of continuous improvement of our benchmarking toolkit.

considered the implications of Jemena's capital MPFP and MTFP benchmarking performance for assessing opex efficiency.

Differences in capitalisation practices such as opex/capex trade-offs do exist among the distribution businesses. These can arise through differing capitalisation policies and/or different opex/capital mixes adopted by businesses in delivering required outputs and outcomes. For example, some distribution businesses (e.g. CitiPower, Powercor, Ergon Energy, and Jemena for the 2021–26 regulatory control period) have changed their capitalisation policy to expense more corporate overheads through a change in their Cost Allocation Method.

The reasons we do not consider that the impact of capitalisation practices, including opex/capex trade-offs, significantly affect Jemena's opex benchmarking performance are set out below.

First, while Jemena has a relatively high ratio of opex to capital inputs (measured as the annual user cost of capital[261], as opposed to capex), we do not accept Jemena's argument that opex/capital input trade-offs are not captured in the opex benchmarking models. Economic theory would suggest that capital inputs would be an explanatory variable in the opex benchmarking models and this was explored in our original model specification. As explained by Economic Insights, a capital input variable was not included in these opex benchmarking models due to data unavailability. However, due to its high correlation with the output variables in the opex models, it is likely that the relationship between capital inputs and opex is captured de facto in the opex models, and thus the omission of capital input is unlikely to significantly affect the efficiency results:

> 'With regard to capital variables, due to the lack of comparable capital data available for Ontario, we were unable to include a capital measure in this instance. … However, we do note that in the Australian data the aggregate capital quantity variable formed by aggregating physical measures of lines, cables and transformers and using annual user costs as weights has a very high correlation of 0.95 with the energy delivered (Energy) output and of 0.94 with the ratcheted maximum demand (RMDemand) output. Similarly the constant price capital stock variable had a correlation of 0.88 with both the customer number (CustNum) and RMDemand output variables. This suggests that the omission of a capital input variable is unlikely to have a significant bearing on the results as it is likely to be highly correlated with the included output variables.'[262]

Second, we have examined the average opex/total cost (opex plus capital annual user cost) ratio for all the distribution businesses as shown in Figure C.1 and C.2 for the

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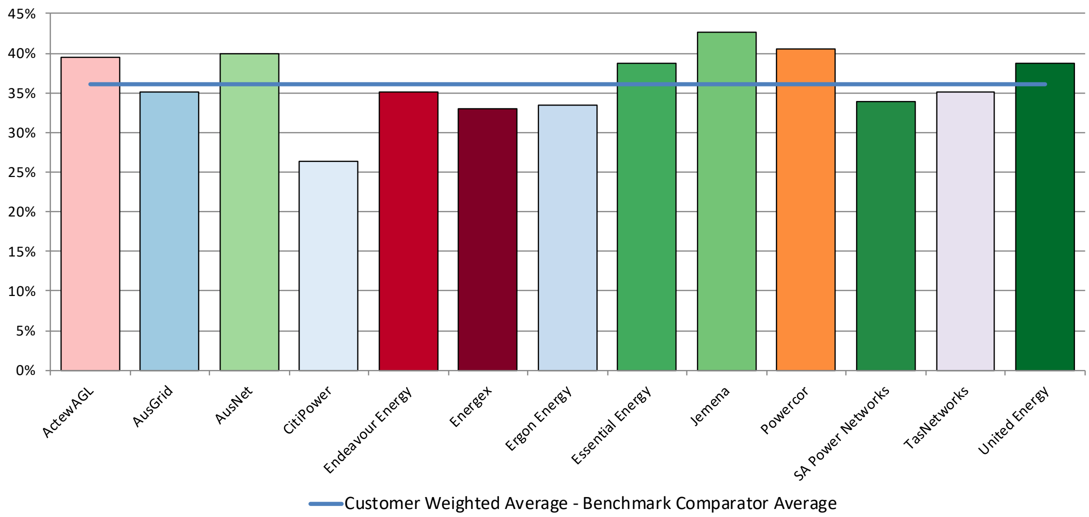
[261] The annual user cost is the cost of using the durable input for one year, which is taken to be the return on capital, the return of capital and the tax component, all calculated in a broadly similar way to that used in forming the building blocks revenue requirement.

[262] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 32.

2006–18 period and 2012–18 periods. Using this approach and consistent with Jemena's submission, we find that Jemena's opex/total cost ratio over both benchmarking periods is higher than the benchmark comparator-average ratio. However, in addition to the previous point, we consider that annual user cost is an imperfect measure of capital inputs, notably due to inconsistencies among the distribution businesses in approaches to asset valuation, asset age and depreciation profile. As a specific example, the Victorian Government adjusted the asset values of the five Victorian distribution businesses for the purpose of equalisation of consumer prices at the time of privatisation in 1995.

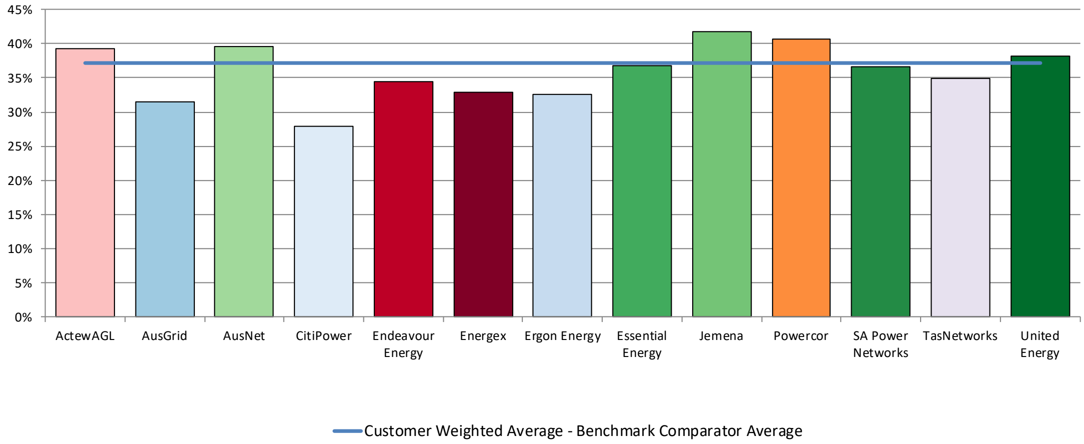
Figure C.1 Opex to total cost ratios for distribution businesses, 2006–18[263]



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

[263] Consistent with the opex series used for economic benchmarking, these charts use 2013-CAM backcast opex for those distribution businesses which have changed their CAM.

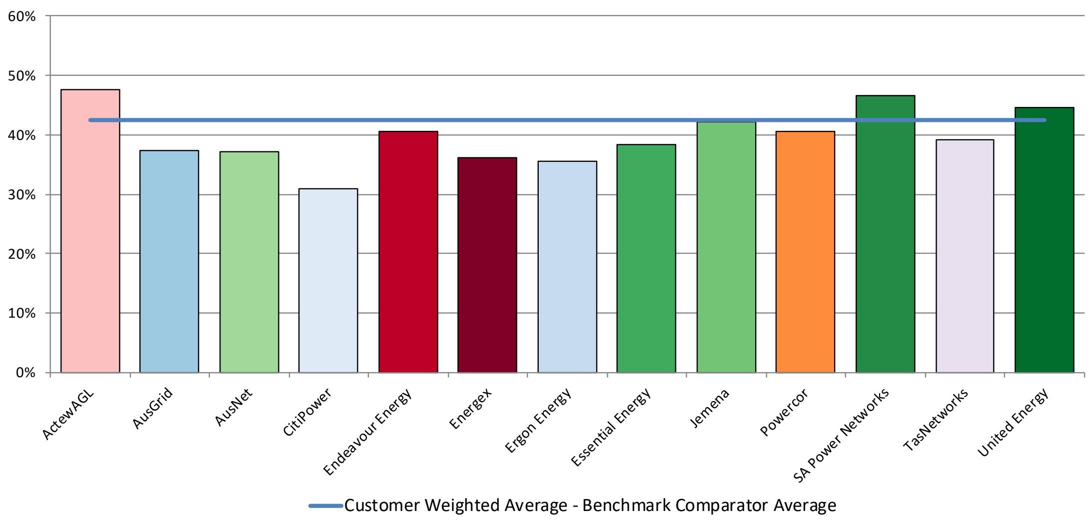
Figure C.2 Opex to total costs ratio for distribution businesses, 2012–18



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

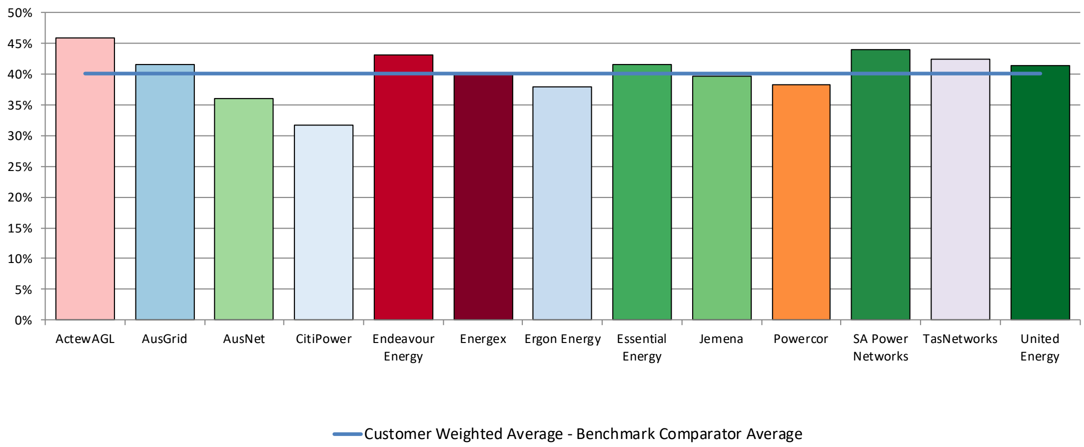
Third, we have examined opex/capex ratios over the two benchmarking periods as a high level measure of the extent to which distribution businesses report and/or use opex relative to capex at the total level, rather than focusing of one particular type of expenditure (e.g. corporate overheads).The average opex/totex ratio for all the distribution businesses is shown in Figure C.3 and Figure C.4 for the 2006–18 period and 2012–18 periods.

Figure C.3 Opex to totex ratios for distribution businesses, 2006–18[264]



Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

Figure C.4 Opex to totex ratios for distribution businesses, 2012–18



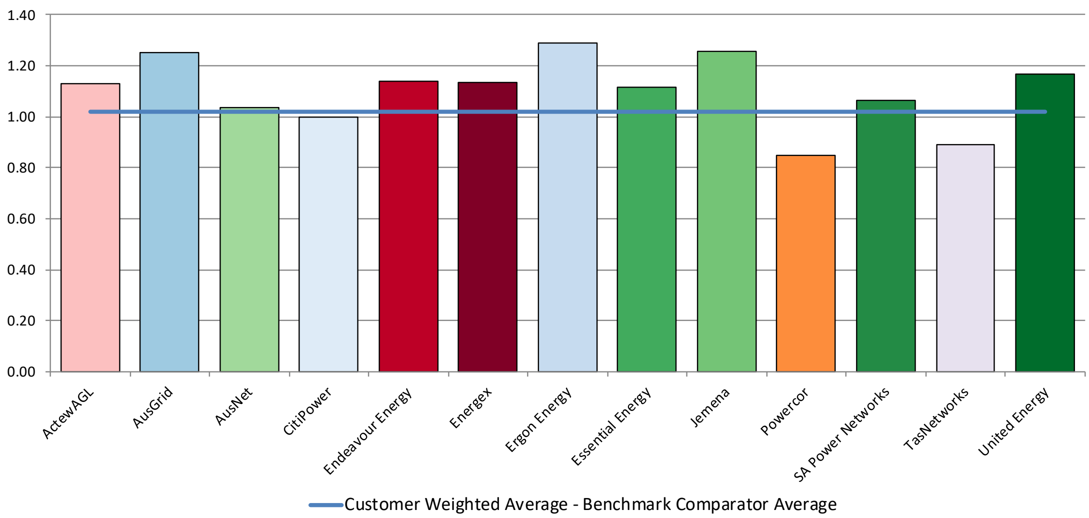
Source: Economic Benchmarking RINs, all distribution businesses; AER analysis.

Using this approach, we find that Jemena's opex/totex ratio is not materially different from the benchmark comparator-average ratio. This suggests that, in terms of annual expenditure, it does not favour opex over capex more than the comparator businesses. This suggests that a positive OEF adjustment for Jemena's opex intensity is not warranted.

264 Consistent with the opex series used for economic benchmarking, these charts use 2013-CAM backcast opex for those distribution businesses which have changed their CAM.

A third possible measure of opex/capital trade-offs is to use the opex and capital input quantity indexes from the MTFP models to construct an index that reflects the ratio of opex to total inputs. This is shown in Figure C.5Figure C.5 for the 2006–18 period.

Figure C.5 Opex to total inputs ratios for distribution businesses, 2006–18[265]



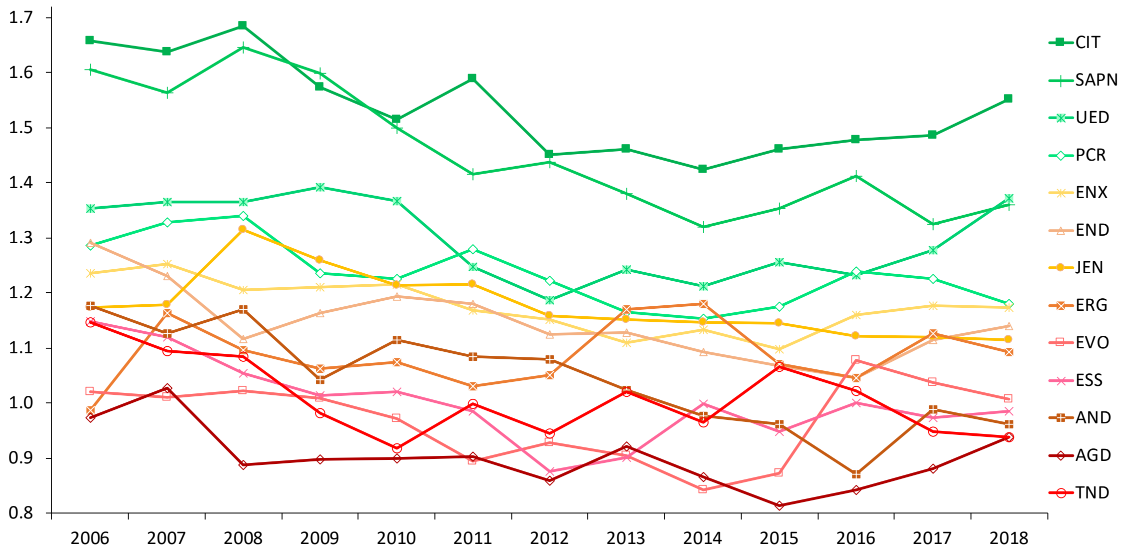
Source: Economic Benchmarking RINs, all distribution businesses; Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report,* 24 August 2020; AER analysis

While useful as a high level gauge of capitalisation practices, we recognise that each of these measures has limitations. As capital assets are long-lived, the use of capex in the opex/totex ratio, even over a long period, may not fully take account for different age asset age profiles and investment cycles among the businesses. The limitations of the opex to total cost ratio have been noted above. In relation to the opex to total inputs ratio, the capital input quantity may not adequately take into account important sources of capex as noted by Jemena, such as capitalisation of overheads.

Fourth, Jemena's argument that it is cost efficient overall is in large part based on its performing well on the top down MTFP (and capital MPFP) benchmarking. These are reproduced below in Figure C.6 and C.7 which show that Jemena ranked relatively highly across both measures.

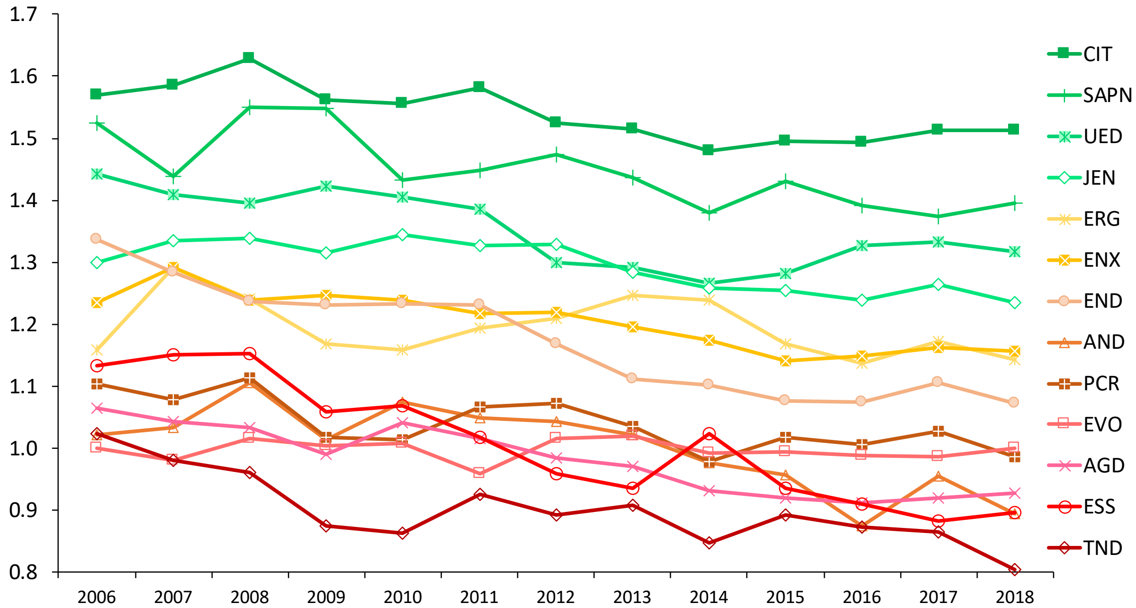
265 Consistent with the opex series used for economic benchmarking, these charts use 2013-CAM backcast opex for those distribution businesses which have changed their CAM.

Figure C.6 MTFP indexes (uncorrected results) by individual businesses, 2006–18



Source: AER, *2019 Annual Benchmarking Report, Electricity distribution network service providers*, November 2019.

Figure C.7 Capital MPFP indexes (uncorrected results) by individual businesses, 2006–18



Source: AER, *2019 Annual Benchmarking Report, Electricity distribution network service providers*, November 2019

However, this conclusion was made on the basis of results in the *2019 Annual Benchmarking Report*. 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.[266]

With these changes, including the corrected output weights, the MTFP and MPFP rankings of the distribution businesses have changed. For Jemena, its MTFP performance with the corrected weights is generally in the bottom four to five of 13 distributors over the 2006–19 period, which can be seen in Figure C.8. Its performance previously, with the uncorrected weights, was in the middle or slightly above the middle of the thirteen distribution businesses.[267]

The corrected output weights result in a similar outcome for the capital MPFP results, with Jemena's performance in the corrected results being around the middle of the thirteen distribution businesses (see Figure C.9). Its performance has had a declining trend since 2012 which is also consistent across the industry. The results with the uncorrected weights, as previously reported, showed Jemena's capex MPFP performance was in the top four distribution businesses.

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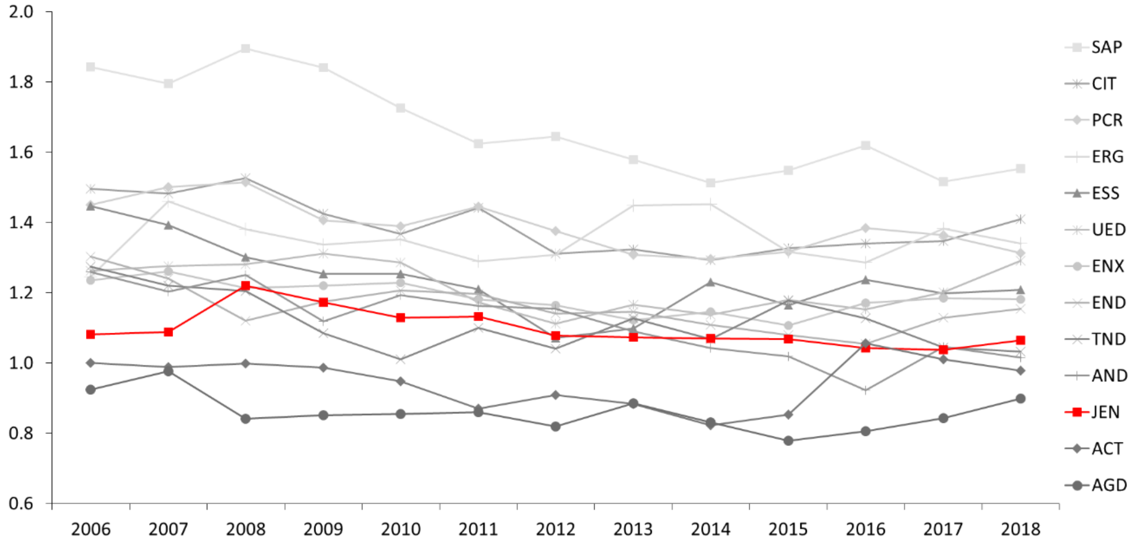
266 Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report*, 24 August 2020. The data updates include revised opex data for Jemena, CitiPower, Powercor and AusNet Services in some recent years. The updated weights for non-reliability outputs reflect Economic Insights' review of 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 on 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*.

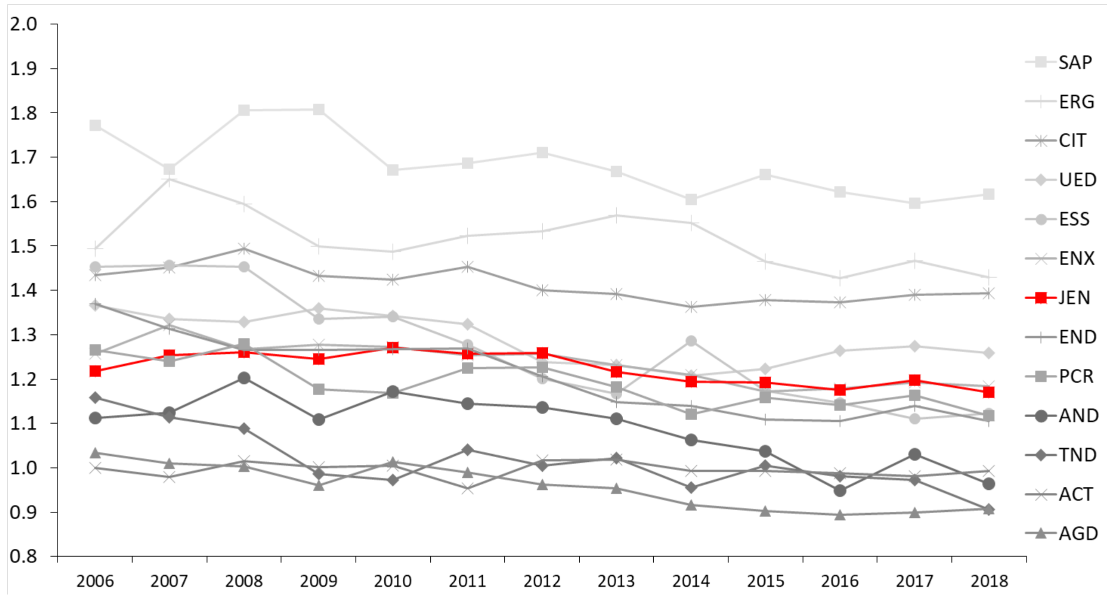
267 The corrected output weights result in more weight being placed on the circuit line output and less on the customer number output. As Jemena has a very small footprint, and relatively low circuit line length compared to the other businesses, increasing the weight on circuit line length result in its ranking being lower.

Figure C.8 MTFP (corrected results) by individual businesses, 2006–18



Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report,* 24 August 2020; AER analysis

Figure C.9 Capital MPFP (corrected results) by individual businesses, 2006–18



Source: Economic Insights, *Revised files for 2019 DNSP Economic Benchmarking Report,* 24 August 2020*;* AER analysis.

D Confidential Appendix - Cyber security step change