FINAL DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 6
Operating expenditure

June 2020

AUSTRALIAN
ENERGY
REGULATOR

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Note

This attachment forms part of the AER's final decision on the distribution determination that will apply to Ergon Energy for the 2020–25 regulatory control period. It should be read with all other parts of the final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

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Attachment A – Negotiating framework

Contents

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network 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 Ergon Energy's revised opex proposal for the 2020–25 regulatory control period.

6.1 Final decision

Our final decision is to accept Ergon Energy's revised opex proposal of $1834.6 million ($2019–20), including debt raising costs, for the 2020–25 regulatory control period. We are satisfied that it reasonably reflects the opex criteria.[1] We have tested Ergon Energy's proposal by comparing it to our alternative estimate of total opex of $2017.7 million ($2019–20).[2] Our alternative estimate is $183.0 million (or 10.0 per cent) higher than Ergon Energy's opex proposal.

For its revised proposal Ergon Energy re-submitted the opex in its initial proposal, which we accepted in our draft decision. While Ergon Energy re-proposed its initial proposal, in its revised proposal it also provided for information an 'internal' opex forecast, which was its internal view of a revised opex forecast using our base-step-trend approach. This took into account updated information, including actual results for base year opex, accounted for the opex savings from its property and ICT capital expenditure (capex) programs, and used our 0.5 per cent per annum forecast for industry-wide productivity growth.[3] This internal forecast was 7.3 per cent higher than its initial proposal.[4] However, for its revised opex proposal, Ergon Energy re-submitted its initial proposal, explaining:

> Recognising this and our commitment to affordable customer outcomes, we have re-submitted the lower opex forecast used in our Regulatory Proposal. This recognises that the AER accepted our January forecast in its Draft Decision, having determined that it was not materially inefficient.[5]

We have drawn on elements of Ergon Energy's internal forecast in developing our alternative estimate of opex.

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1 NER, cl. 6.5.6(c).

2 Includes debt-raising costs. We use the Reserve Bank of Australia's May 2020 *Statement on monetary policy* trimmed mean inflation forecasts for the year ending June 2020. See below for further details.

3 Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36.

4 Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36; Ergon Energy , *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 1; AER analysis.

5 Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36.

Table 6.1 sets out Ergon Energy's revised proposal, our alternative estimate for the final decision and the differences between them.

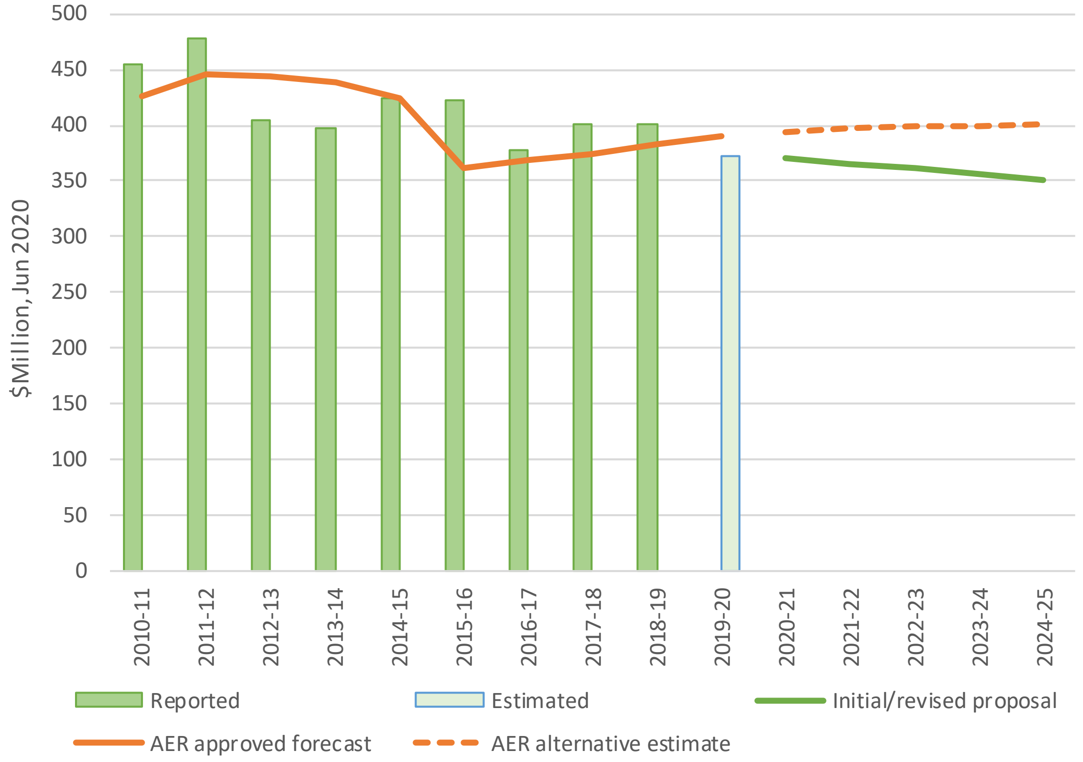
Table 6.1 AER's alternative estimate of total opex compared to Ergon Energy's proposal ($ million, 2019–20)

	Ergon Energy Revised Proposal	AER alternative estimate Final Decision	Difference
Based on reported opex in 2018–19	1898.9	1982.3	83.4
Efficiency adjustment	0.0	-60.6	-60.6
Negative base adjustments	-127.0	-25.6	101.4
Cost Allocation Method adjustments	78.7	27.0	-51.7
Service classification adjustments	0.4	1.3	0.9
2018–19 to 2019–20 increment	36.6	36.2	-0.4
Output growth	56.5	33.9	-22.6
Price growth	3.5	32.7	29.2
Productivity growth	-141.4	-29.2	112.1
Step changes	0.0	-8.5	-8.5
Category specific forecasts	0.0	0.0	0.0
Debt raising costs	28.5	28.3	-0.2
Total opex	1834.6	2017.7	183.0

Source: AER analysis; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.
Note: Numbers may not add up to total due to rounding.

Figure 6.1 shows actual and allowed opex in the previous and current regulatory control periods and Ergon Energy's opex forecast and our alternative estimate in the next period.

Figure 6.1 Historical and forecast opex ($ million, 2019–20)



Source: AER analysis; Ergon Energy, *Regulatory Accounts 2010–11 to 2018–19*; Ergon Energy, *Economic Benchmarking RIN responses 2010 to 2019,* Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019; Ergon Energy, *Post Tax Revenue Model (PTRM) PTRM Distribution*, December 2019.

Note: Excludes debt raising costs.

We derive our alternative opex forecast by nominating an annual opex expenditure 'base' and then adjusting the opex base over time to account for wage growth, expansion of the network and expected productivity growth. We then add or subtract any components of opex that are not appropriately compensated for in base opex or the rate of change. Our approach is explained in section 6.3 and applied in section 6.4 of this attachment.[6]

While we accept Ergon Energy's revised proposal for total opex, the following sets out how we have calculated our alternative estimate and the key differences that result in our higher forecast (which draws on the updated information included in Ergon Energy's 'internal' forecast):

- We have used actual opex in the base year (2018–19) as the starting point for forecast base opex, whereas Ergon Energy's initial proposal (and its revised proposal) used a lower estimate for base year opex.

[6] Our base-step-trend approach is also set out in our expenditure guideline. See AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

- In light of our analysis of the efficiency of base year opex, we have made an efficiency adjustment to base year opex, while Ergon Energy did not.
    - Our assessment of revealed cost data and a range of benchmarking techniques indicates that historically Ergon Energy has been relatively inefficient. Ergon Energy achieved limited reductions in opex over the current regulatory control and did not achieve reductions in the base year. Taking this, and its unique operating environmental factors, into account we consider its base year opex materially inefficient.
- We have included different adjustments to base opex compared to those in Ergon Energy's initial and revised opex proposal. Our alternative estimate:
    - Does not include the removal of the negative base adjustments proposed by Ergon Energy.
    - Includes a smaller negative adjustment (than Ergon Energy's internal forecast) to base year opex to account for a re-allocation of corporate overheads.
    - Includes a lower amount for the additional costs proposed to account for the cost allocation method (CAM) changes (based on a revised estimate provided by Ergon Energy in its internal forecast).
    - Includes a higher amount for the additional costs proposed to account for the service classification changes (based on revised estimates provided by Ergon Energy in its internal forecast).
- Based on Ergon Energy’s internal forecast, we have applied a lower forecast output growth rate compared to Ergon Energy's initial and revised opex proposal, reflecting updated output forecasts and the weights applied to the constituent outputs.
- We have used a higher forecast input price growth rate compared to Ergon Energy's initial and revised opex proposal. We have forecast labour price growth using our standard approach of averaging the forecasts from Deloitte Access Economics (Deloitte), prepared for the AER, and from BIS Oxford Economics, prepared for Ergon Energy. This is a change in the approach adopted in our draft decision of using Deloitte's forecast only. Ergon Energy's relatively low proposed price growth reflects a 0.59 per cent average annual 'unit rate efficiency factor' discount it had made to its input price growth forecast.
- We have applied our 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[7] This is lower than the 2.6 per cent average annual productivity growth forecast Ergon Energy used in its initial and revised opex proposal.

[7] AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

- We have included two negative step changes, for property and ICT capex-related opex savings.
- We have applied the trimmed mean inflation series from the Reserve Bank of Australia's May 2020 inflation update to inflate 2018–19 nominal dollars to June 2019–20 dollars.[8] Our usual implementation is to use the (headline) consumer price index (CPI) forecast for the year ending June 2020. In the current COVID circumstances, we consider that the trimmed mean forecast better reflects core expectations of inflation as set out in the RBA's *Statement on monetary policy*. Further, the trimmed mean smooths the transient volatility in the CPI forecasts in the May *Statement on monetary policy*.

6.2 Ergon Energy's revised proposal

Ergon Energy proposed a total forecast opex of $1834.6 million ($2019–20) for the 2020–25 regulatory control period (see Table 6.2).[9] This is the same amount it submitted in its initial proposal and that we accepted in our draft decision. This is 7.3 per cent lower than Ergon Energy's actual and estimated opex for the 2015–20 regulatory control period.[10]

Table 6.2 Ergon Energy's proposed opex ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Opex excluding category specific forecasts	371.2	365.9	361.3	356.3	351.4	1806.1
Debt raising costs	5.6	5.7	5.7	5.8	5.8	28.5
Total opex	376.8	371.6	367.0	362.1	357.2	**1834.6**

Source: Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.
Note: Numbers may not add up to total due to rounding.

In its initial proposal, Ergon Energy adopted our base–step–trend approach to forecast opex for the 2020–25 regulatory control period.[11] We set out its approach and the key elements of its forecast in section 6.2 of our draft decision.

In its revised proposal, Ergon Energy also provided an 'internal' opex forecast, which was its internal view of a revised opex forecast using base-step-trend, updated for a range of factors, including actual results for base year opex.[12] This forecast was 7.3

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8 Reserve Bank of Australia, *Statement on Monetary Policy – May 2020*, Forecast Table, May 2020, available at https://www.rba.gov.au/publications/smp/2020/may/forecasts.html.

9 Including debt raising costs. Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

10 Including debt raising costs, not including solar feed-in tariffs; AER analysis.

11 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, p. 40.

12 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 1.

per cent higher than its initial opex proposal.[13] However, for its revised opex proposal, Ergon Energy re-submitted its initial proposal, on the basis of its "commitment to affordable customer outcomes" and "AER [acceptance] of our January forecast in its Draft Decision, having determined that it was not materially inefficient."[14]

We have drawn on elements of Ergon Energy's internal forecast in developing our alternative estimate of opex.

6.2.1 Stakeholder views

We received four submissions on Ergon Energy's opex proposal, including from the AER's Consumer Challenge Panel 14 (CCP14), Origin Energy, Canegrowers, and Energy Consumers Australia (ECA). The ECA included a report by Dynamic Analysis to supplement the ECA’s submission. Submissions focused on the issue of efficiency of Ergon Energy's opex.

The CCP14 noted that "given that revealed opex for 2018–19 is above the forecast opex used by the AER in its draft decision, there is the potential for the AER to conclude that Ergon Energy is materially inefficient."[15] Canegrowers similarly noted that we should find that Queensland networks are materially inefficient, as they consistently rank in the bottom quartile in the AER’s opex productivity analysis.[16]

Origin Energy was supportive in principle of Ergon Energy's revised proposal, being largely in line with the AER’s draft decision recommendations, but encouraged the AER to rigorously assess the prudency and efficiency of the revised expenditure proposals to ensure expenditure remains appropriate.[17] Dynamic Analysis submitted that "given the AER has previously accepted the proposed opex as efficient, we consider the revised [opex] proposal is capable of acceptance."[18]

CCP14 also supported the AER's draft decision in relation to real labour price growth and had difficulty in agreeing with the arguments Ergon Energy put forward as a part of its internal forecast.[19]

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13 Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36; Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 1; AER analysis.

14 Ergon Energy, *1.003 - Ergon Energy Revised Regulatory Proposal 2020–25*, December 2019, p. 36.

15 CCP14 - *Advice to the AER on the Energex and Ergon Energy 2020–25 Revised Regulatory Proposals*, *Revised report*, March 2020, p. 19.

16 Canegrowers, *Submission on Energy Queensland (Ergon and Energex): Our revised regulatory proposals and revised tariff structure statements 2020–25*, January 2020, p. 2.

17 Origin Energy, *Submission on the draft decision and revised regulatory proposals for Queensland electricity distributors,* January 2020, p. 1.

18 Dynamic Analysis, *Technical advice to Energy Consumers Australia; Review of Ergon’s revised regulatory proposal*, January 2020, p. 7.

19 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Revised Regulatory Proposals, Revised* report, March 2020, pp. 25–26.

We refer to submissions that relate to specific components of Ergon Energy's opex forecast in section 6.4, where we explain the reasoning for our final decision.

6.3 Assessment approach

Our role is to form a view about whether a business's forecast of total opex is reasonable. Specifically, we must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'. In doing so, we must have regard to each of the opex factors specified in the NER.

If we are satisfied the business's forecast reasonably reflects the opex criteria, we must accept the forecast.[20] If we are not satisfied, we must substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria for the business's forecast.[21] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we are required to consider interrelationships with the other building block components of our decision.[22]

As set out in our draft decision in detail, we generally assess a business's forecast total opex using a 'base-step-trend' approach, as summarised in Figure 6.2.[23]

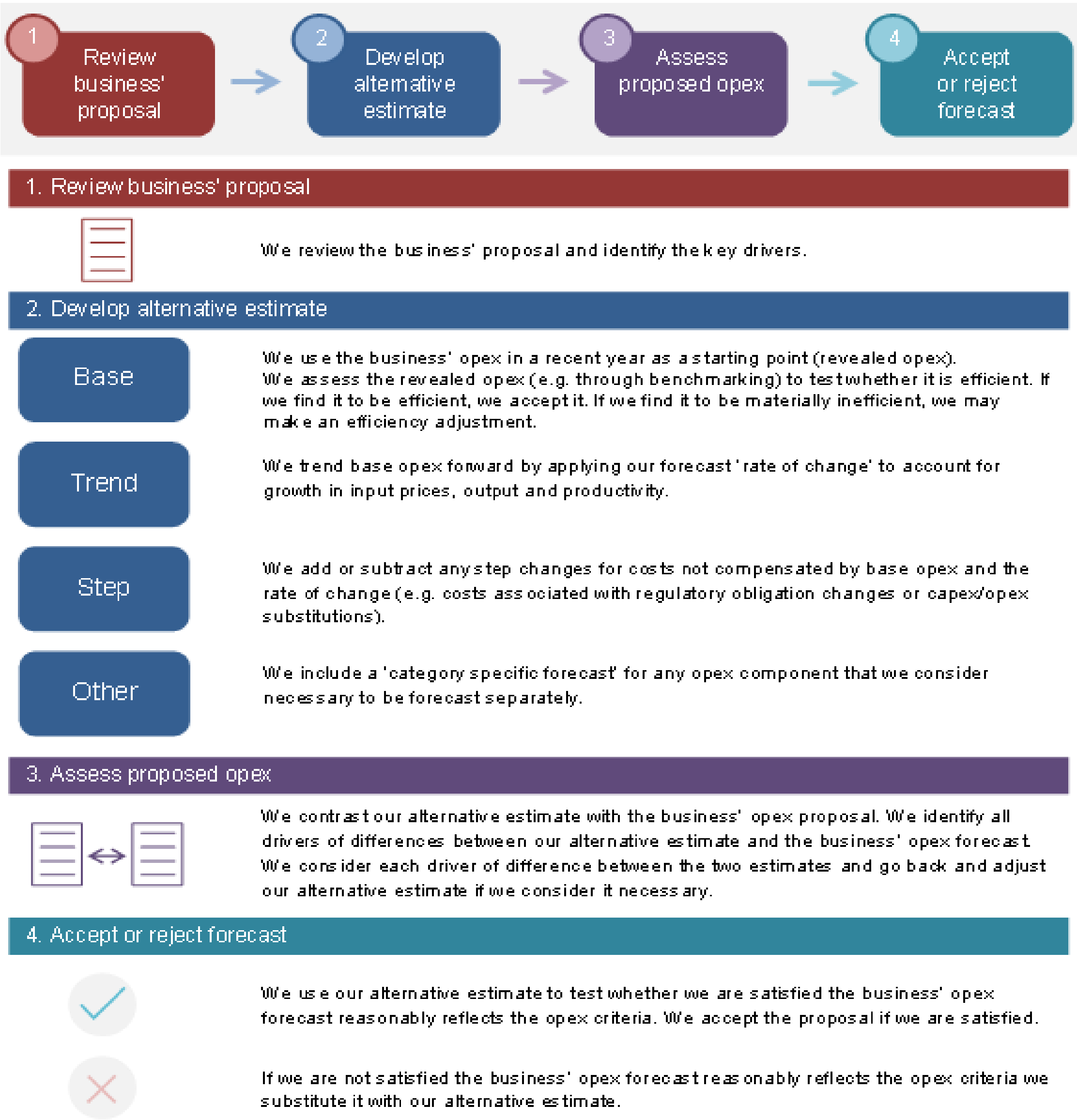
[20] NER, cl. 6.5.6(c).

[21] NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

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

[23] Our base-step-trend approach is also set out in our expenditure guideline. See AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

Figure 6.2 Our opex assessment approach



6.3.1 Interrelationships

In assessing Ergon Energy's total forecast opex we also took into account other components of its revenue proposal that could interrelate with our opex decision.[24] The matters we considered in this regard included:

- the efficiency benefit sharing scheme (EBSS) carryover—the level of opex used as the starting point to forecast opex (the final year of the current period) should generally be the same as the level of opex used to calculate the EBSS carryover

[24] 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).

amounts. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years. In this context, the starting point of our alternative estimate of opex is consistent with the opex used to calculate EBSS carryovers. However, Ergon Energy has re-proposed its initial opex proposal for its revised proposal, which we have accepted. We have taken into account this inter-relationship in our decision.

- the operation of the EBSS in the 2015–20 regulatory control period, which provided Ergon Energy an incentive to reduce opex in the base year
- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and our forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- interactions and trade-offs between the opex and capex proposals.

6.4 Reasons for final decision

For its revised opex proposal, Ergon Energy re-submitted the opex it proposed in its initial proposal, which we accepted in our draft decision.[25] This provides a degree of comfort that Ergon Energy's revised opex proposal is acceptable and reasonably reflects the opex criteria.[26] However, we have tested this by developing an alternative estimate of total opex and comparing it to Ergon Energy's revised opex proposal. Our alternative total opex estimate of $2017.7 million ($2019–20)[27] is $183.0 million (or 10.0 per cent) higher than Ergon Energy's opex proposal of $1834.6 million ($2019–20). On this basis, we maintain our draft decision to accept Ergon Energy's proposed opex forecast.

In this section we set out how we have developed our alternative estimate of opex. This draws on information updated since the draft decision, including actual opex in the base year, further benchmarking analysis and Ergon Energy's internal forecast that it included for information in its revised proposal.

6.4.1 Base opex

Our alternative estimate does not rely on revealed opex in the 2018–19 base year for establishing base opex. Using our benchmarking tools, we find that Ergon Energy's actual opex in the base year is materially inefficient. As a result we have made an

25 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 1.

26 NER, cl. 6.5.6(c).

27 AER analysis; includes debt-raising costs.

efficiency adjustment to actual base year opex to reflect our view of an efficient level of recurrent opex. Our analysis is set out in section 6.4.1.1.

This is a change from the draft decision. The main reason for this change is that actual base year opex was significantly ($24.5 million ($2019–20) or 6.5 per cent) higher than Ergon Energy's estimate used in the draft decision. In the draft decision, we relied on Ergon Energy's estimated opex in 2018–19 to calculate our alternative estimate. We noted this was because, while our revealed cost and benchmarking analysis indicated that Ergon Energy had been historically inefficient, we did not consider its estimated base year opex to be materially inefficient after taking into account the reduction in costs it was forecasting to achieve in 2018–19 and its unique Operating Environment Factors (OEFs). This was a finely balanced assessment and we noted that we would review this position in our final decision.[28]

In section 6.4.1.2 we assesses the other adjustments to base opex proposed by Ergon Energy that are not related to our base opex efficiency assessment, for example, the reclassification of services.

Our conclusions on base opex are summarised in section 6.4.1.3.

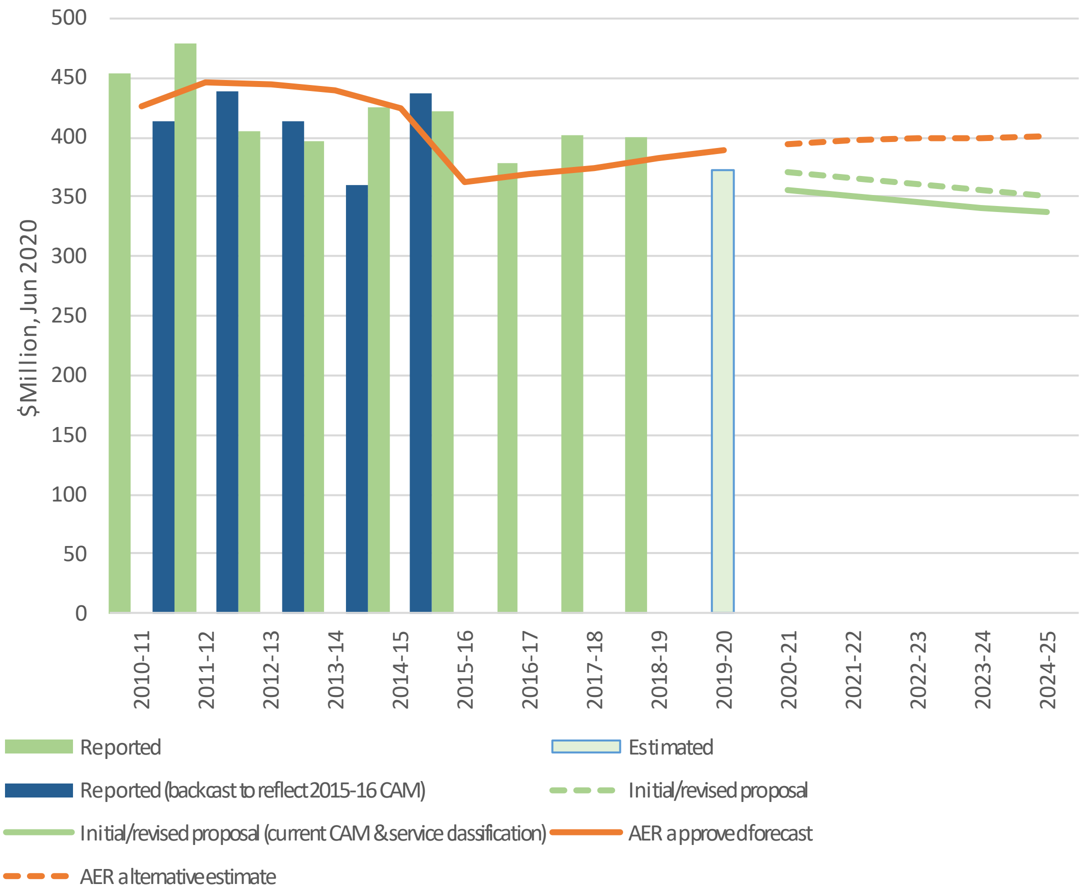
6.4.1.1 Efficiency of base opex

Analysis of Ergon Energy's revealed costs

Ergon Energy's actual opex has remained above the opex allowance set for the current regulatory control period. This can be seen in Figure 6.3. Ergon Energy changed its CAM in 2015–16, the first year of the current regulatory control period. To allow a like-for-like comparison across regulatory control periods, we have presented Ergon Energy's historical and proposed opex on the basis of the one CAM. Specifically, Ergon Energy's actual opex over the 2010–15 regulatory period is shown under both the CAM that applied for that period (the green columns) and backcast using the current CAM (the blue columns). While Ergon Energy's proposed opex incorporates its new CAM that will apply from the start of the next regulatory period (show in the green dash line), we have also presented Ergon Energy's proposed opex recast on the basis of its current CAM (the solid green line). Ergon Energy's new CAM is also reflected in our alternative estimate (the orange dash line).

[28] AER, *Draft decision, Ergon Energy distribution determination 2020−25 Attachment 6 – Operating expenditure*, October 2019, p. 8.

Figure 6.3 Ergon Energy's historical and forecast opex ($ million, 2019–20)



Source: AER analysis; Ergon Energy, *Economic Benchmarking RINs*; Ergon Energy, *Economic Benchmarking RINs (recast*); Ergon Energy, *6.008 - Opex forecast - SCS,* January 2019; Ergon Energy, *17.053 - 2020–25 Regulatory Determination RIN template*, January 2019.

Note: Reported opex for a given year is based on the CAM which applied in that year, and is calculated by total SCS opex (EB RINs) - debt-raising costs (EB RINs) - feed-in tariffs (AER database for FY11–15 and the EB RINs for FY16–17).

Figure 6.3 shows that while Ergon Energy's revealed costs (on a current CAM basis) have followed a marginally decreasing trend from 2010–11 to 2018–19, they have mostly fluctuated, and its most recent three years of opex has risen and likely continues to indicate inefficiencies. Ergon Energy's average annual opex decreased from $412.3 million per year ($2019–20) over the 2010–15 regulatory control period to $400.4 million per year ($2019–20) over the first four years of the current regulatory control period (2015–16 to 2018–19). However, Ergon Energy's opex increased from

$377.7 million ($2019–20) in 2016–17 to $400.7 million ($2019–20) in 2018–19 to be $18.3 million or 4.8 per cent above our October 2015 final decision allowance.[29]

Using our benchmarking tools to assess opex efficiency

Given our revealed cost analysis supports a view that Ergon Energy has not improved its opex efficiency in recent years and its current level of opex may be materially inefficient, we have used our economic benchmarking tools to test the efficiency of Ergon Energy's recurrent opex over time and its base year opex.[30]

Details about our benchmarking approach, including how we take into account OEFs, can be found in section 6.4.1 of our draft decision, and summarised below.

In terms of historical performance, our benchmarking results from the *2019 Annual Benchmarking Report* indicate that Ergon Energy has been relatively inefficient over the 2006–18 period when compared to other distributors in the National Electricity Market (NEM).[31] Figure 6.4 shows that over this period Ergon Energy ranks 11th out of 13 distribution businesses based on the average efficiency scores from five economic benchmarking models[32], with scores ranging from 0.54 (Stochastic Frontier Analysis Cobb Douglas (SFA CD) model) to 0.59 (SFA Translog (SFA TLG) model). These results have not been adjusted for OEFs not already captured in the modelling (which we apply in the next section) and so they do not account for some factors beyond a distributor's control that can affect its benchmarking performance.

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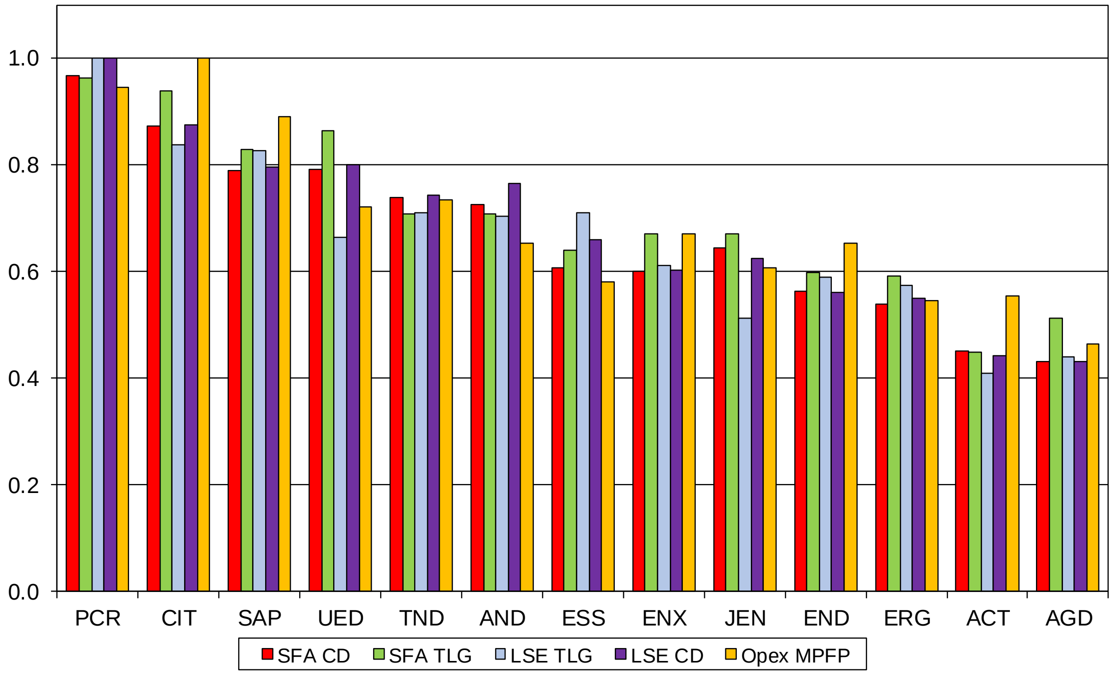
29 AER, *Final Decision Ergon Energy distribution determination - Attachment 7 - operating expenditure* - October 2015, p. 7; AER analysis.

30 NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

31 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019; AER analysis.

32 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 29; AER analysis. The five models are the four econometric models - Cobb-Douglas stochastic frontier analysis (SFACD), Cobb-Douglas least squares econometrics (LSECD), Translog stochastic frontier analysis (SFATLG) and Translog least squares econometrics (LSETLG) - and the opex multilateral partial factor productivity (MPFP) model.

Figure 6.4 Distributors' average opex efficiency scores, 2006–2018



Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 29.

It can take some time for more recent improvements in efficiency by previously poorer performing distributors to be reflected in period average efficiency scores. Considering this, we have also examined Ergon Energy's average performance over the shorter and more recent 2012–18 time period. These results show that while Ergon Energy's average efficiency scores across the models are higher compared to the longer time period (8th out of 13 distribution businesses), they continue to indicate a similar level of relative inefficiency when compared to other distributors in the NEM as seen for the longer period.[33]

To understand the potential drivers of relative inefficiency observed above we have also examined partial performance indicators (PPIs) – a different method of benchmarking.[34] In summary, over the period 2014–18 Ergon Energy does not perform well on an opex per customer or per kilometre of circuit line length basis. Our PPI analysis lends some support to the economic benchmarking analysis and our view that Ergon Energy's opex has been relatively inefficient historically. This analysis is presented in more detail in section 6.4 of our draft decision.

33 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 30.

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

Given the evidence outlined above of the relative inefficiency of Ergon Energy's opex over the 2006–18, 2012–18 and 2014–18 time periods, we have undertaken additional analysis, including further economic benchmarking, to more directly test the efficiency of Ergon Energy's actual opex in the base year. Ergon Energy submitted that 2018–19 is the most suitable year for its base year because it is the most recent year for which audited data will be available, and because the level of opex in 2018–19 will be more reflective of ongoing requirements than other recent years.[35] As in the draft decision, we accept 2018–19 as a suitable base year.

As discussed further in section 6.4.1.2, we have assessed the efficiency of Ergon Energy's base year opex without making the adjustment proposed by Ergon Energy for removal for atypically high storm costs in 2018–19.

While Ergon Energy's opex MPFP score has improved somewhat since 2015–16, the first year of the current regulatory control period, Ergon Energy's MPFP scores based on its 2018–19 base year opex continue to place it as a relatively poor performer amongst distributors in the NEM. Ergon Energy has been in the bottom three in terms of opex MPFP in most of the years over the 2006–2018 time period, and is placed last in the base year 2018–19 against other distributors' opex MPFP performance in 2017–18. We note that this comparative performance has occurred during a time of significant improvement in opex MPFP of some of the other distributors in the NEM.

Figure 6.5 presents the results of opex MPFP benchmarking, which allows for the comparison of opex productivity levels between service providers and across time. The chart shows all distributors in the NEM using actual opex up to 2017–18 and actual opex in 2018–19 for Ergon Energy and Energex's proposed base years. We note these opex MPFP results have also not been further adjusted for OEFs and so do not account for some factors beyond a distributor's control that can affect its costs and benchmarking performance.

While Ergon Energy's opex MPFP score has improved somewhat since 2015–16, the first year of the current regulatory control period, Ergon Energy's MPFP scores based on its 2018–19 base year opex continue to place it as a relatively poor performer amongst distributors in the NEM. Ergon Energy has been in the bottom three in terms of opex MPFP in most of the years over the 2006–2018 time period, and is placed last in the base year 2018–19 against other distributors' opex MPFP performance in 2017–18.[36] We note that this comparative performance has occurred during a time of significant improvement in opex MPFP of some of the other distributors in the NEM.

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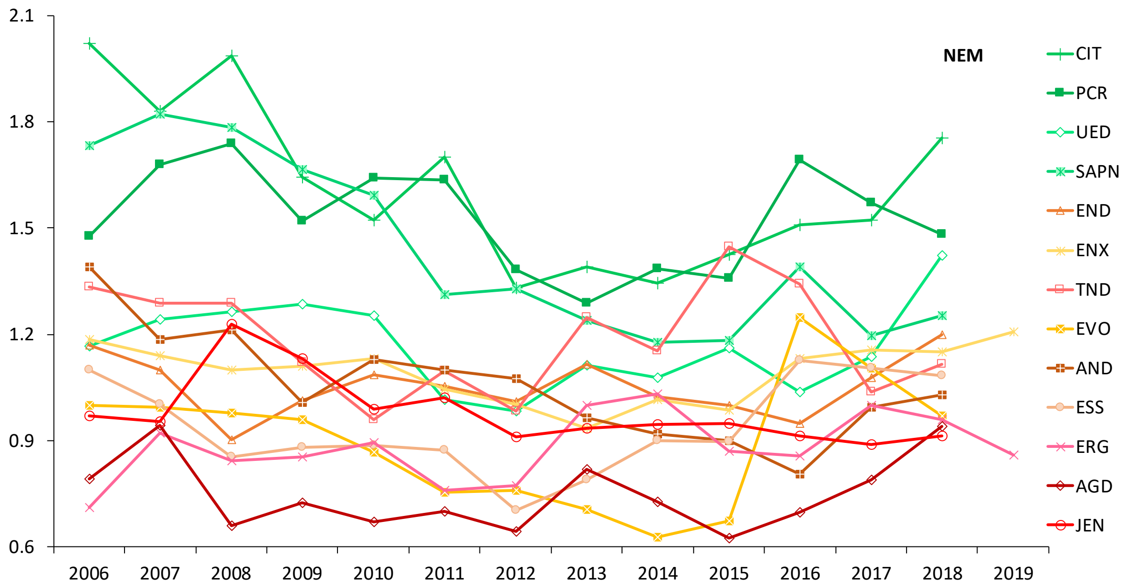
35 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, pp. 46-47.

36 A comparison of Ergon Energy and Energex's opex MPFP scores in 2018–19 and opex MPFP scores in 2017–18 involves comparing actual scores in 2017–18 with the scores for 2018–19 based on Ergon Energy and Energex's actual base year opex. This comparison assumes other distribution businesses scores do not change in 2018–19.

Figure 6.5 Opex multilateral partial factor productivity, 2006–2018, with Ergon Energy and Energex data to 2019



Source: Economic Insights, *Memorandum Productivity of Energex's and Ergon Energy's proposed base year opex*, 25 March 2020.

Note: The opex MPFP scores have not been further adjusted for OEFs. Consistent with our approach of using the most recently available data, the chart uses actual opex for all distributors up to 2017–18 and actual opex for Energex and Energex for 2018–19.

We have also examined the efficiency of Ergon Energy's 2018–19 base year opex using the results of our econometric modelling adjusted for cost differences driven by OEFs not already captured in the modelling. Our econometric models produce period-average opex efficiency scores for distributors across the 2006–18 and 2012–18 periods. We use these results to estimate the level of opex an efficient benchmarked service provider operating in Ergon Energy's circumstances would require to deliver its network services (which comprise by far the major proportion of distributors' standard control services opex) in 2018–19.

To derive our estimates of base year opex of a benchmark service operator as shown in Figure 6.6 and Figure 6.7 for the longer and shorter benchmarking periods respectively, we follow the following steps for each of the four sets of econometric modelling:

- We first average Ergon Energy's actual opex over the relevant period.
- We then compare Ergon Energy's efficiency score over that period, against a benchmark comparison score of 0.75. This reflects the upper quartile of possible efficiency scores, and reflects our conservative approach to setting a benchmark comparison point.
- We then adjust the benchmark comparison point for potential differences in OEFs between Ergon Energy and the reference firms that are not already captured in the modelling.

- Where Ergon Energy's efficiency score is below the adjusted benchmark comparison score, we adjust Ergon Energy's period-average opex by the difference between the two efficiency scores. This results in an estimate of period-average opex that we consider is not materially inefficient at the midpoint of the relevant period.
- We then roll forward this period-average opex estimate to a 2018–19 base year using the rate of change which captures output and productivity growth. This results in an estimate of opex that we consider is not materially inefficient in 2018–19.

Where Ergon Energy's base year opex is above our estimates of efficient opex this provides evidence of material inefficiency, and informs the size of any efficiency adjustment we decide to make to base year opex.

Further details about our methodology can be found in Box 6.1 of our draft decision and in a spreadsheet published alongside this final decision.[37]

Figure 6.6 and Figure 6.7 present the range and average of our estimates of efficient base year network services opex over the 2006–18 and 2012–18 periods, and compare these to Ergon Energy's actual 2018–19 base year network services opex. To allow for a 'like for like' comparison, we requested Ergon Energy to recast its base year opex on the basis of network services opex under the CAM in place in 2013.[38] This is to be consistent with opex data used for benchmarking analysis and is shown by the green columns in Figure 6.6 and Figure 6.7. The four-model average is represented by the dotted line. This is $366.2 million ($2019–20) for both time periods.

The results using both time periods show that Ergon Energy's recast base year network services opex of $377.5 million ($2019–20) is above the average of our four estimates of efficient network services opex ($366.2 million ($2019–20)). Given the conservatism built in to our benchmarking, particularly the use of a 0.75 benchmark comparator and accounting for OEFs, this supports a finding that Ergon Energy's base year network services opex is materially inefficient.

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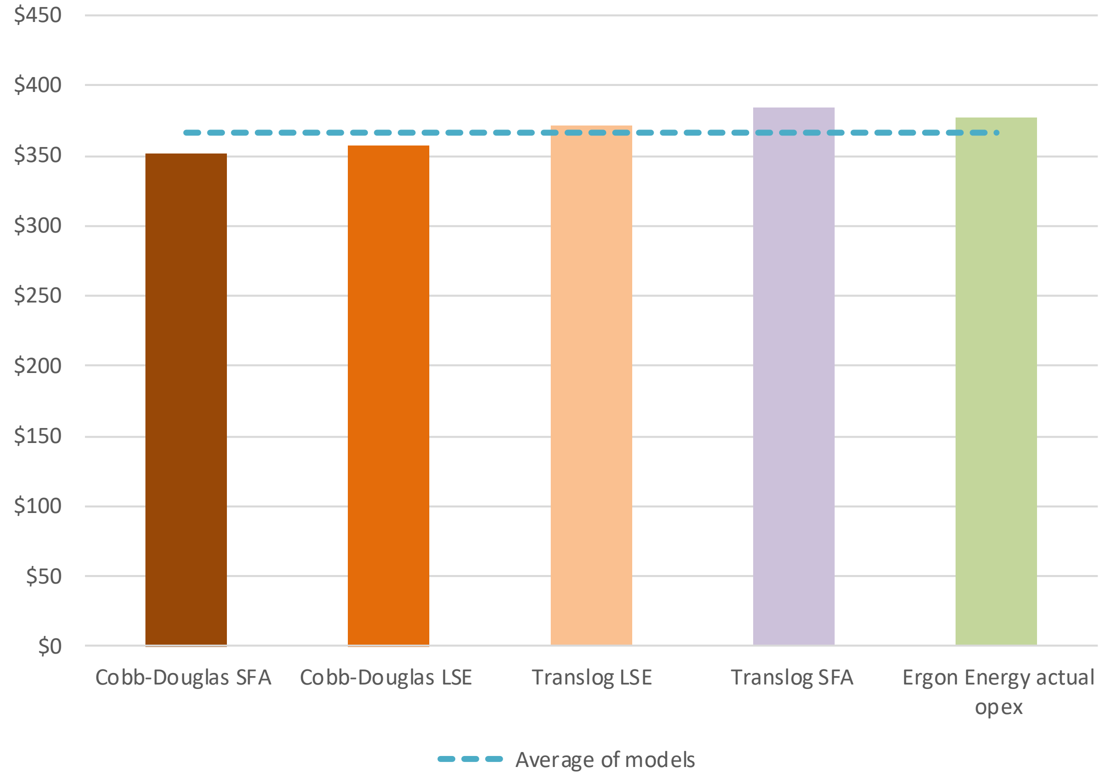
[37] AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

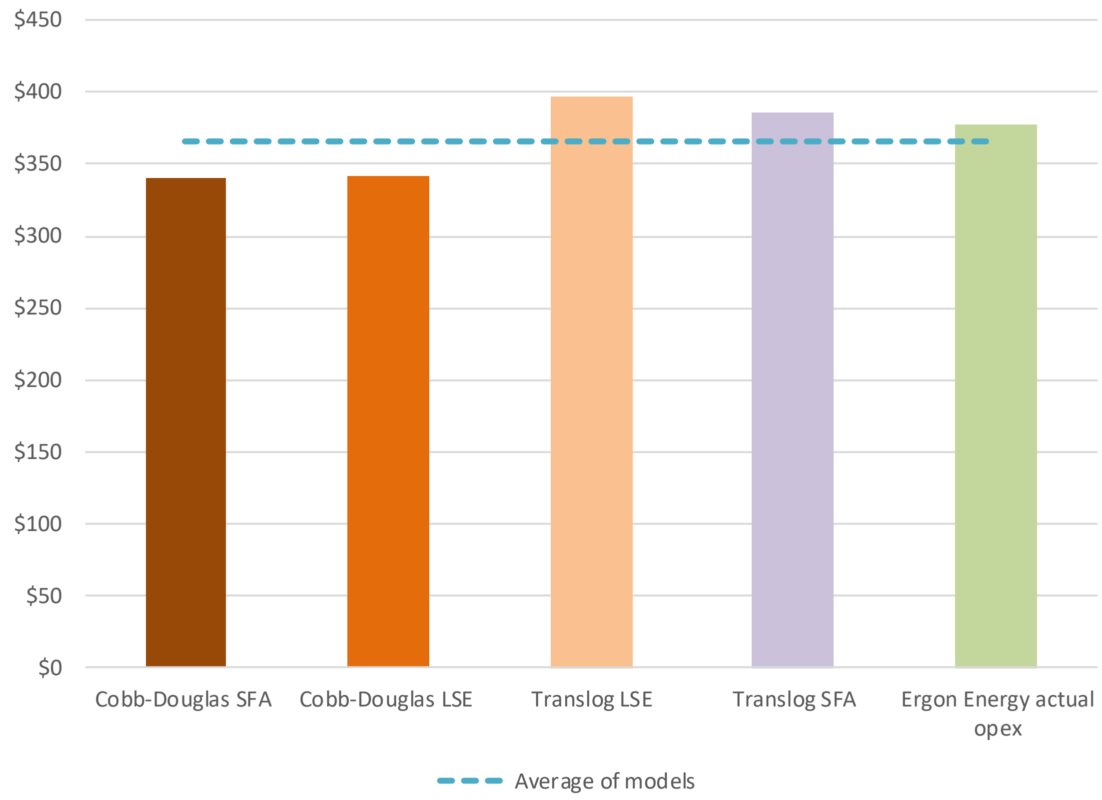
[38] Ergon Energy, *Information request 69* – Q1, 20 November 2019, p. 1.

Figure 6.6 AER estimates of efficient base year opex and Ergon Energy's base year opex in 2018–19 ($ million, $2019–20), 2006–18



Source: AER analysis; AER, *Annual Benchmarking Report*, November 2019.
Note: all expressed in 2013 CAM network services opex terms.

Figure 6.7 AER estimates of efficient base year opex and Ergon Energy's base year opex in 2018–19 ($ million, $2019–20), 2012–18



Source: AER analysis. Economic Insights, *2019 Annual Benchmarking Report*, November 2019.

Note: all expressed in 2013 CAM network services opex terms.

Source: AER analysis; AER, *Annual Benchmarking Report*, November 2019.
Note: all expressed in 2013 CAM network services opex terms.

As set out below, in light of this finding, and the submissions from Ergon Energy and other stakeholders (discussed in the following section) we have made an efficiency adjustment to its base year opex for our alternative estimate.

Ergon Energy and Frontier Economics and other stakeholder views on base opex efficiency, and our response

Ergon Energy's initial and revised proposals included benchmarking and category analysis supporting its view of the efficiency of its base year opex.[39] Ergon Energy also engaged Frontier Economics to assess the robustness and reliability of the AER's benchmarking approach used in the draft decision and to advise on the efficiency of

39 Ergon Energy, *6.003 - Base Year Opex Overview 2020–25*, January 2019, pp. 19-34; Frontier Economics, *AER Benchmarking - A report prepared for Energy Queensland,* 15 January 2019; Ergon Energy , *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 16–17 and 42–45.

the actual 2018–19 base year opex in light of our *2019 Annual Benchmarking Report* released following our draft decision.[40] On the basis of Frontier Economics' report, Ergon Energy submitted that its base year opex is not materially inefficient.[41]

In relation to our benchmarking approach, Frontier Economics' report contended that the AER's benchmarking approach suffers from major methodological shortcomings that mean the AER should interpret its benchmarking results very cautiously. It states that many of the issues raised by the Australian Competition Tribunal have not been addressed properly by the AER and remain unresolved.[42] It also raises a number of other issues, including:

- Scope for model misspecification[43]
- Reliance on too narrow a set of models and benchmarking approaches[44]
- Use of data on international distributors[45]
- Benchmarking rural distributors against urban distributors.[46]

Frontier Economics' report contended that there is no evidence that Ergon Energy's base year opex (with or without normalising for unusually high storm costs – discussed below in section 6.4.1.2) is materially inefficient. Frontier Economics considers that this conclusion holds under several scenarios, including both under the AER's approach and its own modelling.[47]

Economic Insights, engaged by us, reviewed Frontier Economics' report in relation to benchmarking and outlined several areas of concern with Frontier Economics' analysis.[48] We consider that Economic Insights' review of Frontier Economics' arguments is sound. In light of Frontier Economics' arguments and Economic Insights' response, we are satisfied that our current benchmarking approach remains appropriate and provides a sound and conservative evidence base to support our conclusion that Ergon Energy's base year opex is materially inefficient.

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40 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019.

41 Ergon Energy , *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp.16–17.

42 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp.7–8.

43 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p.4 and pp. 11–12.

44 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p.4 and pp. 8–9.

45 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p.4 and pp. 9–10.

46 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p.4 and pp. 10–11.

47 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 1–2.

48 Economic Insights, *Memorandum: Comments on 2019 Frontier Economics Benchmarking Reports for EQ*, 11 March 2020.

Appendix A summarises the technical concerns raised by Frontier Economics about our approach and Economic Insights' response to each of the concerns. We have also published Economic Insights' memo responding to Frontier Economics' report along with this decision.

In relation to the OEF adjustments, Frontier Economics considers the AER erred in its analysis, including on our reasoning for estimating the bushfire obligations OEF, failure to consider Ergon Energy's network accessibility OEF, and our reasoning for excluding the OEF for occupational health and safety. It also points out that changes to the composition of the group of reference distribution network service providers that we use as the benchmark (i.e. AusNet Services is no longer identified as a reference firm) may mean that previously immaterial OEFs are now material. It also argues that the AER's reasons for excluding immaterial OEFs in the draft decision are unconvincing, and questions the AER's approach of making post-modelling adjustments.[49]

We have also had regard to Frontier Economics' concerns about our approach to OEFs. We maintain that our OEF approach is a pragmatic one that draws on the best available evidence to reflect distributors' unique operating circumstances. As noted in our *2019 Annual Benchmarking Report*, we intend to refine and update our OEF analysis over time to ensure that the OEFs are continually improved and stay relevant.[50]

We agree with Frontier Economics on the need to consider and quantify Ergon Energy's network accessibility OEF, and have included this OEF adjustment in our benchmarking analysis. In the final decision for the Ergon Energy 2015–20 regulatory determination, we applied a material OEF adjustment of 1.1 per cent to account for the higher cost of access route maintenance (due to adverse climate and heavy rainfall) that Ergon Energy incurs compared to the reference distributors at that time.[51] We agree with Frontier Economics' observation that the network accessibility circumstances faced by Ergon Energy is unlikely to have materially changed since our 2015 assessment.[52] On the basis of updated data, we have applied an OEF adjustment of 0.93 per cent for Ergon Energy.

Appendix B summarises the arguments raised by Frontier Economics on our OEF approach and our response to each of these arguments.

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49 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 22-52.

50 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 27.

51 AER, *Preliminary decision Ergon Energy distribution determination 2015−20 Attachment 7 – Operating expenditure*, April 2015, p. 248. We upheld this number in the final decision. See AER, *Final decision Ergon Energy distribution determination 2015−20 Attachment 7 – Operating expenditure*, October 2015, p. 53.

52 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p. 37.

As foreshadowed in the draft decision[53], we have revised the OEF adjustments used in the draft decision to reflect the results from the *2019 Annual Benchmarking Report.* In particular, using the period average opex over the benchmarking periods (instead of the 2015 historical opex used by Sapere-Merz). The calculations for our revised OEF adjustments (including an additional OEF for network accessibility) are shown in the OEF calculations summary spreadsheets (for the shorter and longer time periods) and the vegetation management and network accessibility OEF spreadsheet included on our website with this final decision.[54]

The assessment of the efficiency of Ergon Energy's base year opex was also a key issue raised in submissions to the AER in response to the revised proposal. CCP14 stated that the AER's conclusion that Ergon Energy has been historically inefficient was reinforced by the most recent AER benchmarking analysis for 2017–18 that was released after the draft decision.[55] It noted that "given that revealed opex for 2018–19 is above the forecast opex used by the AER in its draft decision, there is the potential for the AER to conclude that Ergon Energy is materially inefficient."[56]

CCP14 made submissions on the importance of benchmarking for consumers:

> Consumers advocated for many years for the AER to undertake benchmarking and have strongly supported it since its introduction. We believe it now serves as a crucial role in allowing consumers to advocate on the need for networks to constantly improve their efficiency replicating what happens in a workably competitive market.[57]

Canegrowers similarly noted that we should find that Queensland networks are materially inefficient, as they consistently rank in the bottom quartile in the AER's opex productivity analysis.[58] Origin Energy noted that it supports the significant progress that the AER has made in driving the Queensland networks towards achieving more efficient expenditure levels and the resultant impact on affordability.[59]

We have considered the issues raised in submissions in our analysis of Ergon Energy's base opex. We agree with stakeholders' views that Ergon Energy has been relatively inefficient over the benchmarking periods. As outlined above, our benchmarking analysis of Ergon Energy's base year opex supports a finding that this level of opex is likely to be materially inefficient.

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[53] AER, *Draft decision, Ergon Energy distribution determination 2020−25 Attachment 6 – Operating expenditure*, October 2019, p. 74.

[54] AER, *Final decision Ergon Energy 2020–25 - OEF calculations summary long period*, May 2020; AER, *Final decision Ergon Energy 2020–25 - OEF calculations summary short period*, May 2020; AER, *Final decision Ergon Energy 2020–25 - OEFs veg management & network accessibility model*, May 2020.

[55] CCP14 - *Revised submission on the draft decision and revised proposal - Ergon Energy*, March 2020, p. 19.

[56] CCP14 - *Revised submission on the draft decision and revised proposal - Ergon Energy*, March 2020, p. 19.

[57] CCP14 - *Revised submission on the draft decision and revised proposal - Ergon Energy*, March 2020, p. 21.

[58] Canegrowers, *Submission on the draft decision and revised proposal - Ergon Energy*, January 2020, p. 2.

[59] Origin Energy, *Submission on the draft decision and revised regulatory proposals for Queensland electricity distributors,* January 2020, p. 1.

Efficiency adjustment to Ergon Energy's base year opex

Taking the above analysis into account, we have concluded that on balance these results support the finding that Ergon Energy's actual base year opex is not at a level that is consistent with what an efficient benchmarked service provider operating in Ergon Energy'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 Ergon Energy's base year opex is materially inefficient. Consequently, we have made an efficiency adjustment to Ergon Energy's actual base year opex[60] for our alternative estimate of base opex to establish a level of base opex that we consider reflects an efficient distributor's opex.

The size of the efficiency adjustment we have made to Ergon Energy's base year opex is 3.0 per cent. We have derived this by comparing our estimate of efficient base year opex with actual base year opex (all in 2013 CAM network services terms). As set out above, our estimate of efficient base year opex is the midpoint of the four-model-average rolled forward efficient estimates of base year opex ($366.2 million ($2019–20)). Ergon Energy's base year opex (in 2013 CAM network services terms) is $377.5 million ($2019–20), a difference of $11.2 million ($2019–20).

6.4.1.2 Other adjustments to base year opex (apart from efficiency)

Apart from efficiency adjustments, other adjustments may be made to base year opex prior to applying the rate of change.

Ergon Energy proposed a number of base opex adjustments in its initial and revised proposal and the internal forecast provided in its revised proposal.[61]

The adjustments Ergon Energy included in its internal forecast, which we have used to inform our alternative estimate, are:

- Adjustments to the actual opex it reported for base year 2018–19, which also then impact EBSS carryovers for the current period. These comprise:
    - a decrease in base year opex to remove non-recurrent costs due to abnormally high storm activity in the base year, which decreases its base opex by $12.2 million ($2019–20) per year and its forecast opex over the 2020–25 regulatory control period by $60.8 million ($2019–20)[62]

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[60] This adjustment is applied to base year opex after making the other adjustments to base year opex discussed in section 6.4.1.2.

[61] As noted in section 6.1, Ergon Energy's revised proposal included an 'internal' opex forecast, which was its internal view of a revised opex forecast using our base-step-trend approach. This took into account updated information, including actual results for base year opex. As this reflected updated information and addressed issues raised in our draft decision we have drawn on elements of Ergon Energy's internal forecast in developing our alternative estimate of opex.

[62] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 46-47.

  - A decrease in base year opex as a true up to remove over-recovery of corporate overheads in the base year, which decreases its base opex by $12.9 million ($2019–20) per year and its forecast opex over the 2020–25 regulatory control period by $64.4 million ($2019–20).[63]

- Forward-looking base opex adjustments to reflect changes in how opex will be reported in the next regulatory control period, comprising:
  - A positive adjustment to include the impact of the new CAM taking effect from July 2020, which increases its base opex by $5.4 million ($2019–20) per year, and its forecast opex over the 2020–25 regulatory control period by $27.0 million ($2019–20)[64]
  - A positive adjustment for service classification changes, which increases its base opex by $0.3 million ($2019–20) per year, and its forecast over the 2020–25 regulatory control period by $1.3 million ($2019–20).[65]

In our alternative estimate we have included the forward-looking adjustments outlined above, included a lower amount than Ergon Energy for the true up to remove over-recovery of corporate overheads and not included the storm normalisation adjustment. In the sections below we provide more detailed discussion of each of these adjustments and the reasons for our final decision.

Separate to the above adjustments, we have also made adjustments to base year opex for movements in provisions and Demand Management Innovation Allowance (DMIA) costs, in line with our standard approaches. In arriving at final base opex, we have also added the estimated change in opex between the base year and the final year, in line with our standard approach.

Storm normalisation

In the internal forecast included in its revised proposal, Ergon Energy proposed that $12.2 million ($2019–20) should be removed from base year opex for the adverse impact of atypically high storm costs on emergency response expenditure.[66] Ergon Energy made the corresponding revenue adjustment to its EBSS calculation, as explained in Attachment 8.

We have not removed the proposed amount from base year opex, (and therefore not made the corresponding non-recurrent efficiency adjustment in the EBSS as proposed by Ergon Energy). This is on the basis that total opex is similar to the previous year –

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[63] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 48-49, Ergon Energy, *9.002 Efficiency Benefits Sharing Scheme (EBSS) Model*, December 2019.

[64] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 18 and pp. 31-41.

[65] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 17-18.

[66] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 46-47.

$401.0 million in 2017–18 and $400.7 million in 2018–19 ($2019–20). While categories of opex will generally fluctuate from year to year, we consider that a non-recurrent efficiency adjustment is generally only justified where there has been a non-recurrent change at the total opex level. For example, while emergency response expenditure for Ergon Energy has increased in 2018–19 (by $8.4 million ($2019–20)), vegetation management has decreased (by $9.8 million ($2019–20)). This example illustrates that it would be inappropriate to allow a non-recurrent adjustment in one direction for one category (e.g. emergency response) but not the reverse adjustment for another category, with opex at the total level unchanged. We consider our decision to not remove the proposed amounts for non-recurrent costs is consistent with our view that opex at the total level is generally recurrent, and with our preferred top-down approach to opex assessment.

True up for corporate overheads over-recovery

In the internal forecast included in its revised proposal, Ergon Energy proposed that a negative adjustment of $12.9 million ($2019–20) should be made to its reported base year opex to true up between:

- Real-time overhead recoveries that were charged out during a given year using budgeted rates and point in time allocation percentages and
- Actual year-end outcomes for these costs.[67]

For reasons set out below, we accept the need for such an adjustment and have included it in our alternative estimate. However, the amount we have removed from base year opex is a lower amount of $5.1 million ($2019–20).

Under Ergon Energy's current (2015–20) CAM, corporate overheads ("shared support costs") are recovered throughout the year by a rate that is added to direct opex and direct capex. The rates for direct opex and direct capex used for this purpose are a forecast of corporate overheads allocated to opex (capex) as a percentage of forecast direct opex (capex).[68]

Inevitably, there will be forecast error (e.g. forecast direct expenditure and/or forecast corporate overheads will not equal actuals). This will result in either over-recovery or under-recovery of these corporate overheads at the end of the financial year. We understand that where this balance is material[69], under Ergon Energy's 2015–20 CAM the balance is re-allocated to opex and capex. However, where the balance is immaterial, these balances remain un-allocated – i.e. they do not get reported in

[67] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 48-49; Ergon Energy, *9.002 Efficiency Benefits Sharing Scheme (EBSS) Model*, December 2019.

[68] Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 48-49.

[69] Ergon Energy states in its revised proposal opex attachment that materiality was assessed in accordance with accounting standards at approximately $20 million. See Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 48.

standard control service opex or capex. Ergon Energy stated that while this is a proper application of its approved 2015–20 CAM, excluding any under- or over-recovery balance deemed immaterial from its reported opex means that Ergon Energy has been either slightly understating or slightly overstating reported actual costs (within this materiality limit).[70]

In its internal forecast, Ergon Energy proposed to ignore this immateriality limit, and included adjustments to base year opex (and to all four years for EBSS carryover calculation purposes[71]) to reflect the over-recovery of corporate overheads in that year. Its proposed approach was to allocate the over-recovery balance ($12.9 million, ($2019–20)) in 2018–19 (and each of the immaterial balances in the prior years of the 2015–20 regulatory control period) 100 per cent to opex, with no allocation to capex. This reflects the approach that would have occurred under its previous, 2010–15, CAM. Ergon Energy submitted this gives a better view of the actual underlying cost of its base year for opex forecasting, and is then applied consistently to prior years to maintain integrity between the base-step and trend forecasting approach and the EBSS scheme.[72]

We accept the case for an adjustment to true up base year opex for corporate overheads over- or under-recoveries. This is because we consider that this will better reflect underlying opex in the base year, which is important in establishing base opex for opex forecasting purposes.

The specific approach we have adopted for our alternative estimate differs from that used by Ergon Energy. Our approach allocates the balance of over- or under-recoveries between opex and capex on the basis of proportional direct opex and direct capex. This is because we consider this approach will obtain adjusted base opex that is more reflective of underlying opex than Ergon Energy's approach. We also note that this is broadly the approach adopted in Energex’s current CAM. We have made corresponding adjustments to reported opex for EBSS purposes, as explained in Attachment 9 of this final decision[73], and to reported capital expenditure for the 2015–19 period, as explained in Attachment 5, section A.7, of this final decision.

Cost allocation method

We have included in our alternative estimate the additional $5.4 million ($2019–20) per year of costs Ergon Energy included in its internal forecast to account for the new CAM.

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70 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 49.

71 See our EBSS decision: AER, *Final decision Ergon Energy distribution determination 2020−25 Attachment 9 – Efficiency Benefits Sharing Scheme*, May 2020, pp. 7–8.

72 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 48-49.

73 AER, *Final decision Ergon Energy distribution determination 2020−25 Attachment 9 – Efficiency Benefits Sharing Scheme*, May 2020, pp. 11–12.

Our draft decision did not include this adjustment, on the basis that Ergon Energy was not able to adequately explain and justify this proposed increase in opex. In the draft decision, we detailed our views about the gaps in the information we received from Ergon Energy and what information we would require should Ergon Energy wish to propose similar adjustments in its revised proposal.

On the basis of the new information provided in its internal forecast, we are satisfied that Ergon Energy has made the case and provided sufficient information to justify inclusion of these CAM changes as a base opex adjustment. As a part of its internal forecast, Ergon Energy provided a clear explanation of the various adjustments, including detailed spreadsheet modelling of underlying calculations.[74] It also provided a report by audit firm PwC, which attested to the rigor and veracity of the proposed adjustment.[75]

Service classification change

In line with our draft decision[76], and as Ergon Energy included in its internal forecast, we have included an increase in our alternative estimate of base opex of $0.3 million ($2019–20) for Ergon Energy to account for the service classification change. This positive adjustment was proposed for changes in service classification related to emergency recoverable works costs incurred when a customer or third party damages the network.[77] For reasons set out in section 6.4 in the draft decision we maintain our draft decision to accept this adjustment. However, as noted in the draft decision, we do not propose to accept a similar adjustment in future revenue determinations.

We have included in our alternative estimate an adjustment of $0.3 million ($2019–20). In line with the draft decision, we have calculated our adjustment on the basis of the approach adopted in our previous determinations of using the historical average unrecovered unregulated Emergency Recoverable Works costs. Specifically, our adjustment is based on the annual cost of repairing third party damage to its network (calculated using 3-year average historic actual costs) less the revenue recovered from parties found liable for causing the damage (calculated using 3-year average historic receipts from liable parties).[78] Ergon Energy agreed and adopted this approach in its internal forecast.[79]

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74 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 18 and pp. 31-41; Ergon Energy, *7.007 CAM Reconciliation model*, December 2019.

75 PwC, *7.008 - Report on your Cost Allocation Model (CAM) model*, December 2019.

76 AER, *Draft decision, Ergon Energy distribution determination 2020−25 Attachment 6 – Operating expenditure*, October 2019, pp. 49-51.

77 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 17–18; Ergon Energy, *Information request 40 – Q2a*, 5 June 2019, p. 2.

78 Ergon Energy, *Information request 51 – Q10*, 27 June 2019, p. 8.

79 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 17–18.

6.4.1.3 Conclusion on revised base opex for our alternative estimate

Taking into account the efficiency and other base opex adjustments we have made, we have derived our alternative base opex number as shown in detail in our opex model, which is published on our website with this decision. At a high level, it is built up as follows:

- Start with reported base year opex (after adjusting for movement in provisions and the DMIA) of $396.5 million ($2019–20).
- Deduct efficiency adjustment of -$12.1 million ($2019–20)[80], leaving $384.3 million.
- Add other base opex adjustments (accounting, service classification, true up adjustment, estimated change in opex between the base year and the final year) of net $7.8 million ($2019–20).[81]

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[82]

In its revised proposal, reflecting its initial proposal, Ergon Energy adopted the approach we have used in our previous determinations to forecasting the rate of change with some variations.

- Price growth: To forecast labour price growth Ergon Energy took the average of the wage price index (WPI) forecast applied by us in our draft decisions for the NSW distributors and that of the consultants BIS Oxford Economics. However, Ergon Energy applied an annual 'unit rate efficiency factor' discount of -0.6 per cent to the average of its labour price growth forecast. It then estimated overall input price growth by calculating the weighted average of its forecast labour and non-labour price growth using our input price weightings.[83]
- Output growth: Ergon Energy used our previous approach to estimate output growth using forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput weighted using all four benchmarking models.[84] Ergon Energy provided two forecasts of growth of the four outputs: one set in its opex model and a second and more recent set in its regulatory determination regulatory information notice (RIN).

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80 The amount of $12.1 million ($2019–20) differs to the $11.2 million ($2019–20) figure that was obtained by taking the difference between our estimate of efficient base year network services opex and actual base year network services opex. This generated the resulting efficiency adjustment in percentage terms (3.0 per cent), which is then applied in our opex model to the broader *standard control services* opex, resulting in an efficiency adjustment in dollar terms of $12.1 million ($2019–20).

81 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

82 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

83 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, p. 50.

84 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, pp. 50–51.

- Productivity growth: Ergon Energy used a 2.6 per cent annual productivity growth forecast in contrast to our 0.5 per cent per annum forecast.[85]

The rate of change proposed by Ergon Energy decreases its base opex by approximately 1.4 per cent each year.

Contrasting this approach, in its internal forecast of the rate of change for price growth, Ergon Energy updated the WPI forecasts, using an average of the two forecasts from Deloitte and BIS Oxford Economics, and did not apply the annual 'unit rate efficiency factor' discount of -0.6 per cent.[86] Ergon Energy applied our standard approach to output growth, with updated output forecasts.[87] Further, for productivity growth it used our 0.5 per cent annual forecast rather than a 2.6 per cent annual forecast.[88] This results in a rate of change of 0.6 per cent per year.

In our alternative estimate, we have included an average rate of change forecast of 0.7 per cent per year.[89] We explain how we forecast rate of change in our alternative estimate, and how it differs from Ergon Energy's forecast, below.

6.4.2.1 Forecast price growth

We have included forecast average annual real price growth of 0.6 per cent in developing our alternative opex estimate.[90] This increases opex by $32.7 million ($2019–20). In contrast, Ergon Energy forecast annual real price growth of 0.2 per cent in its revised and initial proposal[91] and 0.5 per cent in its internal forecast.[92]

As per our previous approach, our price growth forecast is a weighted average of forecast labour price growth and non-labour price growth.

To forecast labour price growth, we use an average of the real WPI growth forecasts for the relevant jurisdiction's electricity, gas, water and waste services (utilities) sector produced by Deloitte, for the AER, and BIS Oxford Economics, for Ergon Energy.

This is in line with our standard approach, and is a change from the approach in the draft decision of using the WPI growth forecasts provided by Deloitte only, which reflected our analysis that over the period 2007 to 2018 Deloitte’s real WPI growth

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85 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, pp. 51-52.

86 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 20-23.

87 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 23-24.

88 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 24.

89 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

90 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

91 Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

92 Ergon Energy, *7.006 - Opex forecast - SCS*, December, 2019.

forecasts had been more accurate.[93] As discussed in section 6.4.2.1 of Attachment 6 of the SA Power Networks final decision,[94] in light of further analysis and stakeholder feedback, we have reverted to our standard approach. We have used updated WPI forecasts from Deloitte and BIS Oxford Economics since the draft decision.

To forecast real non-labour price growth, we have applied the forecast change in CPI resulting in zero real non-labour price growth. Ergon Energy has adopted the same approach in its forecasts.[95]

We and Ergon Energy have applied the same weights to account for the proportion of opex that is labour and the proportion that is non-labour (59.7:40.3).[96]

6.4.2.2 Forecast output growth

We have included forecast average annual output growth of 0.6 per cent in developing our alternative estimate of forecast opex.[97] This increases our base opex by $33.9 million ($2019–20). In contrast, Ergon Energy forecast annual output growth of 1.0 per cent in its revised and initial proposal[98] and 0.6 per cent in its internal forecast.[99]

Our output growth forecast is a weighted average of the output growth rates forecast using the specification and weights from the five benchmarking models presented in the *2019 Annual Benchmarking Report*.[100] The details of how we forecast our year-on-year output growth are set out in section 6.4 of our draft decision.

In our draft decision we stated that we would update our output weights to reflect the results from all four of our economic benchmarking models in the *2019 Annual Benchmarking Report*, which we published in late November 2019. We have used the updated weights to forecast our alternative estimate of forecast opex for this final decision. We note that this includes adding the weights from a fifth benchmarking model, being the stochastic frontier analysis translog model. The stochastic frontier analysis translog model previously did not perform well in regards to monotonicity for the longer time period (2006–17). With the data updates and revisions for the *2019*

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93 Stakeholders raised concerns with the labour price growth forecasts in submissions to SA Power Networks' proposal for the 2020–25 revenue determinations. Consequently, we analysed how close the forecasts from both Deloitte and BIS Oxford Economics have been to actual WPI growth over the period 2007 to 2018. We found BIS Oxford Economics persistently over-forecast real WPI growth. In contrast, Deloitte's real WPI growth forecasts have been more accurate. See AER, *Draft decision, SA Power Networks distribution determination 2020−25 Attachment 6 – Operating expenditure,* October 2019, pp. 28-33.

94 AER, *Final decision, SA Power Networks distribution determination 2020−25 Attachment 6 – Operating expenditure*, May 2020, pp. 15–21.

95 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, p. 50.

96 We applied Economic Insights' benchmark opex price weightings for labour and non-labour as reflected in our 2017 Annual benchmarking report. For more detail, see: Economic Insights, *Economic benchmarking results for the Australian Energy Regulator's 2017 DNSP benchmarking report*, 31 October 2017, p. 2.

97 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

98 Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

99 Ergon Energy, *7.006 - Opex forecast - SCS*, December, 2019.

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

Annual Benchmarking Report, the model now performs relatively well and was included in the results. The updated weights are shown in Table 6.3.

Table 6.3 Output specification and weights derived from economic benchmarking models

Output	MPFP	SFACD	LSECD	LSETLG	SFATLG
Customer numbers	31.00%	67.43%	68.95%	52.95%	69.51%
Circuit length	29.00%	15.08%	15.56%	15.74%	14.84%
Ratcheted maximum demand	28.00%	17.50%	15.48%	31.31%	15.65%
Energy throughput	12.00%				

Source: Economic Insights*, AER DNSP 2019 benchmarking data files: AER DNSP Opex Eff Scores 2006–2018*, 15 July 2019. AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019; AER analysis.

Note: Numbers may not appear to add up to 100 per cent in this table due to rounding.

6.4.2.3 Forecast productivity growth

We have included forecast productivity growth of 0.5 per cent per year in our alternative estimate.[101] This decreases our alternative estimate by $29.2 million ($2019–20). This is consistent with our final decision in the industry wide review to forecasting opex productivity growth, which we concluded in March 2019.[102] In its initial and revised proposal, Ergon Energy forecast opex productivity growth of 2.6 per cent per year for the 2020–25 regulatory control period.[103] In contrast, in its internal forecast Ergon Energy included a forecast of 0.5 per cent per year productivity growth.[104]

Our productivity growth forecast is a sector-wide productivity forecast that we believe reflects the level of productivity that an efficient distributor engaging in good industry practice should be able to achieve as part of business-as-usual operations. These improvements come from such things as the adoption of new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.

6.4.3 Step changes

Ergon Energy's revised proposal (reflecting its initial proposal) did not include any step changes.[105] However, the internal opex forecast prepared by Ergon Energy and submitted for information with its revised proposal included two negative step changes

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101 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

102 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

103 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, pp. 51-52.

104 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, p. 24.

105 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25,* January 2019, p. 40.

totalling -$8.5 million for opex/capex trade-offs in relation to its ICT and property capex.[106]

We have examined Ergon Energy's internal forecast to inform our alternative estimate of opex. Based on information provided by Ergon Energy, we agree with Ergon Energy's submission that the increased capex in these two areas leads to a reduction in opex over the next (2020–25) regulatory control period. We are satisfied with the evidence put forward on the existence and materiality of these capex/opex trade-offs. We have therefore included these negative step changes in our alternative estimate.

6.4.4 Category specific forecasts

We have included a debt raising cost forecast of $28.3 million ($2019–20) in our alternative estimate.[107]

Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred 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 discuss this in attachment 3 Rate of Return of this final decision.

6.4.5 Assessment of opex factors under NER

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the 'opex criteria' under the NER, we must have regard to the 'opex factors'.[108]

We attach different weight to different factors when making our decision to best achieve the National Electricity Objective. This approach has been summarised by the Australian Energy Market Commission as follows:[109]

> 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 6.4 summarises how we have taken the opex factors into account in making our final decision.

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106 Ergon Energy, *7.001 - Revised Regulatory Proposal for the 2020–25 Regulatory Period - Internal Operating Expenditure Forecasts*, December 2019, pp. 25-30.

107 AER, *Final decision Ergon Energy distribution determination 2020–21 to 2024–25, Opex model*, May 2020.

108 NER, cl. 6.5.6(e).

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

Table 6.4 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 our most recent annual benchmarking report. Second, we must have regard to the benchmark opex that would be incurred by an efficient service provider over the forecast period. The *Annual Benchmarking Report* is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark opex that would be incurred by an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant forecast period. We have estimated an alternative opex estimate and have compared it with Ergon Energy's proposal over the relevant regulatory control period. In doing this we had regard to the information set out in our most recent benchmarking report.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	To assess Ergon Energy's opex forecast and develop our alternative estimate, we have used Ergon Energy's actual opex in 2018–19 as the starting point. We have examined Ergon Energy's historical actual opex and compared it with that of other distribution network services providers.
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	This factor directs us to have regard to the concerns of consumers, as revealed to us in their engagement with the distributors. Additionally, this factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their proposals, such that they are aware of, communicate and factor in the needs of consumers. Based on the information provided by Ergon Energy in its proposal and CCP14's advice, we consider Ergon Energy consulted adequately in developing its revised opex proposal, although note CCP14's view that this was made more difficult by the amount of new information following the AER's draft decision and limited customer resources.[110]
The relative prices of capital and operating inputs	We have adopted price growth forecasts that account for the relative prices of opex and capex inputs. We generally consider capex/opex trade-offs in considering proposed step changes. One reason we will include a step change in our alternative opex forecast is if the service provider proposes a capex/opex trade-off. We consider the relative expense of capex and opex solutions in considering such a trade-off. In the internal opex forecast provided in its revised proposal, Ergon Energy included two step changes as capex/opex trade-offs, which we included in our alternative estimate of opex.
The substitution possibilities between operating and capital expenditure.	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

110 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Revised Regulatory Proposals*, *Revised report*, March 2020, p. 14–17.

Opex factor	Consideration
	relationship between capital, opex and outputs.
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 Ergon Energy's opex in the 2015–20 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have had regard to the EBSS and the consistency of it and Ergon Energy's opex forecast for the 2020–25 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 assessment techniques assess the efficiency of a network service provider's opex and/or capital expenditure at a total level. Given the use of our top-down tools, and given stakeholders have not raised issues in relation to related parties, we did not consider it proportionate in this context to examine any of Ergon Energy's related party arrangements in any detail.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A1(b).	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.	Ergon Energy stated it accepts the AER's framework and approach position to the demand management incentive scheme and demand management innovation allowance.[111]
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 identify any RIT-D project submitted by the business and ensure the conclusions are appropriately addressed in the total forecast opex. Ergon Energy did not submit any RIT-D project for its distribution network.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify Ergon Energy of any other opex factor.

Source: AER analysis.

[111] Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020–25*, January 2019, p. 106.

A Summary of Economic Insights' review of Frontier Economics' report on benchmarking

Technical concerns raised by Frontier Economics	Economic Insights' response
Tribunal recommendations	
The Tribunal’s criticisms on benchmarking approach not been adequately addressed in draft decision.[112]	The AER has made several changes in response to Tribunal, including: uses an average of four/five economic benchmarking models, and supporting tools including PPIs; use of a revised OEF approach and further improved data quality among distributors. The predictions from the SFACD model used in informing the allowances for the 2015 NSW/ACT resets have proven to be quite accurate, given their actual opex over the over the 2014–19 period. This lends further support to the validity of the AER's benchmarking approach. As noted in the remade decisions, distributors appear to have responded to the strong incentives imposed by the AER's regulatory regime, including the use of economic benchmarking, to reduce its opex over the current regulatory period.[113]
Bottom–up benchmarking	
The Tribunal directed the AER to remake its 2015 decisions by, among other things, undertaking a bottom–up review of forecast opex, which the AER has not undertaken.[114]	The Tribunal did not define exactly what it meant by ‘bottom–up’ analysis, and there is no one definition. A bottom–up engineering assessment at the process level would likely involve a significant and onerous data collection activity for each regulated distributor, which can often be costly and invasive. The AER includes PPIs at the total cost and cost category level in order to examine costs from a more bottom-up perspective.
Poolability of urban and rural distributors	
Frontier Economics stated that its statistical testing suggests rural and urban samples should not be pooled together, as they face different cost challenges.[115] Frontier Economics considered that the AER could modify its existing models to allow for differences between rural and urban distributors. It presented a method for doing this, which involves including either a rural or urban distributor dummy variable in	Economic Insights notes that Frontier Economics' claimed statistical test showing that urban and rural distributors should not be pooled in the benchmarking analysis has been conducted only for one model and over one time period. Frontier Economics also does not state what type of hypothesis test has been conducted in its poolability analysis and does not provide diagnostic analysis. However, based on Economic

112 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp.7–8.

113 AER, *Final Decision - Ausgrid 2014–19 electricity distribution determination*, January 2019, p. 21.

114 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p. 9.

115 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 10–11.

Technical concerns raised by Frontier Economics	Economic Insights' response
the AER's models and then interacting that dummy variable with each of the key explanatory variables in the models.	Insights' analysis of Frontier Economics' files across many of Frontier Economics' models, many counter-intuitive results are observed, indicating significant problems with Frontier Economics' models. There are several instances of incorrectly signed estimated coefficients (implying a change in opex would have an implausible impact on output) and a substantial number of monotonicity violations (elasticities of the incorrect sign at particular data points). The pooling test 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, this point does not neatly fit the sample, as a number of Australian distributors have a network that is a mixture of highly urbanised areas and rural areas. It is also unclear whether the application of this arbitrary cut-off point is appropriate for the overseas distributors with only two NZ distributors then being classified as urban and only two Ontario distributors then being classified as rural. Because of the logarithmic form of the AER's 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 actually improved by having diverse characteristics in the sample. If all included distributors have similar characteristics, as would be the case in having separate models for urban and rural distributors, then the models would find it hard to provide robust parameter estimates. Inclusion of rural and urban distributors in the one sample is consistent with common regulatory practice internationally.
Poolability of Ontario distributors with Australian sample	
Similar to the urban/rural split, statistical tests show that Ontarian distributor data should not be pooled with data on Australian and New Zealand distributors.[116]	The application of 'poolability' tests in this instance is flawed. International data is included as the benchmarking models cannot reliably produce estimates using only Australian data, due to the limited time–series variability within the Australian data. It is therefore not unexpected that the estimated coefficients from Australian/NZ appear to be different from the full model in a 'poolability' test. But this is because the former cannot be reliably estimated. As above with rural and urban distributors, estimation accuracy is improved by having a diverse sample. Technologies used in distributing electricity across the three countries are common. Inclusion of country dummy variables allows for systematic differences in operating environments between countries. Where operating conditions differ, this is likely to affect total opex in levels, rather than the output coefficients. As was the case above with rural and urban distributors, upon Economic Insights' analysis of the files for the Frontier

116 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 9-10.

Technical concerns raised by Frontier Economics	Economic Insights' response
	Economics models, several instances of incorrectly signed estimated coefficients and monotonicity violations were observed, indicating significant problems with the Frontier Economics models.
Model misspecification	
Frontier Economics stated that while it recognises that the AER has broadened the set of models it uses in its benchmarking analysis, there is little evidence of validity tests commonly used in econometrics to evaluate the adequacy of a model.[117] As an example diagnostic investigation, Frontier Economics plotted the residuals of the LSE–TLG model estimated over the 2006–2018 period. The residuals, which can be interpreted as percent prediction errors, are plotted against a normal distribution. If the residuals were normally distributed, the points would lie on a straight line. This is not the case.	The plot Frontier Economics presents is linear for the vast majority of observations (as expected) with a small number of residuals deviating from the line in the tails. While Frontier Economics' report does identify these latter observations, Economic Insights' examination of the Frontier Economics files showed that the 'outlier' tails are made up entirely of Ontario and New Zealand observations. Hence the Frontier Economics' claim of potential LSE–TLG model 'misspecification' has no impact on the Australian distributor analysis (noting that the inclusion of international data is to obtain robust parameter estimates, rather than to identify the efficiency of international distributors). The asymptotic properties of the LSE estimator do not rely upon an assumption of normality of the disturbance term. Further, on closer inspection, Frontier Economics' Stata file indicates that the scatterplot plot analyses the exponent of the residuals rather than the residuals. This makes the reported scatterplot plot analysis invalid.
Frontier Economics stated that statistical tests can be conducted to evaluate the comparative fit of the models to the data. Results of its testing of the fit of the Translog model versus the Cobb Douglas model suggests that the latter model is not an acceptable simplification of the Translog model.	Frontier Economics' reported results indicate that the Cobb Douglas model should be rejected in favour of the Translog model on this basis. This result is not surprising and would be consistent with similar hypothesis test results presented in Economic Insights reports in the past. In most cases, when one has a sufficiently large data set, one would expect a statistical test to indicate that the Translog model is a better fit to the data relative to the Cobb Douglas model, since the Translog model is a second-order approximation to an arbitrary functional form while the Cobb Douglas model is a more restrictive first-order approximation. However, the advantage of added flexibility of the Translog comes with the disadvantage of greater propensity to obtain monotonicity violations for some data points. There are thus trade-offs in every modelling decision that is made.
The importance/relevance of monotonicity violations in assessing a model's validity	
Minor monotonicity violations should not disqualify a translog model from being used to assess the efficient base year level of opex for distributors. The AER's uses of the econometric models do not involve calculating elasticities for specific observations, as is done by Economic Insights when testing for monotonicity.[118]	Econometric opex cost function models should satisfy the requirement that an increase in output can only be achieved with an increase in cost. Because the translog models include second order terms, there is a need to check that the estimated cost elasticities for each output are positive at each observation.

[117] Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p.4 and pp. 11-12.

[118] Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 14-18.

Technical concerns raised by Frontier Economics	Economic Insights' response
	The efficiency score calculations incorporate the residuals of the estimated model, where these residuals are calculated at each data point and thus make use of the localised elasticities. As demonstrated, a negative output elasticity implies a production possibility curve with an incorrect (positive) slope. Given the reliance on these elasticities, it is therefore necessary to test that they obey the monotonicity requirement.
Bootstrapping	
Frontier Economics employed bootstrapping to derive confidence intervals for the estimates of base year target opex calculated from the econometric models used by the AER. It also noted a statement by Professor Coelli (from Economics Insights) on Data Envelope Analysis (DEA) which it claimed endorsed the use of bootstrapping.[119]	Frontier Economics have taken Professor Coelli's views out of context. Bootstrapping is a resampling technique that is useful when attempting to assess the influence of sampling variability on an estimated model. If the data is a census, as is the case with the data included in the benchmarking, then no sampling is involved in selecting the data set. Given the benchmarking data is not a sample, the application of bootstrapping techniques is inappropriate. Further, bootstrapping is not recommended for use with SFA due to the complexities involved and the potential biases it introduces. Finally, all of Economic Insights' economic benchmarking reports for the AER have provided information on the statistical reliability of the efficiency scores derived from the SFA and LSE models. However, in regulatory applications, statistically constructed confidence intervals have not been used to set a range of possible efficient values.
OEF adjustment methods	
Frontier Economics criticised the AER draft decision for not: • investigating the inclusion of additional cost driver variables in its model, which should become more feasible over time as the benchmarking sample size increases; and • making ex-ante adjustments for any costs associated with OEFs that are unexplained, or poorly explained, by the cost driver variables that are included in the model—as Ofgem does.[120]	The ability to include additional OEF variables in the models directly is limited by data availability. If these variables are not available for the overseas distributors, the direct inclusion of the variables in the models is not possible. Further, and importantly, degrees of freedom considerations and correlation among exogenous variables in regressions limit the number of operating environment variables that can be included directly in economic benchmarking models in practice. In common with most other regulatory economic benchmarking studies, the AER uses a range of methods to allow for operating environment differences. These include ex-ante data adjustment, direct incorporation of OEFs in models, ex-post adjustment and the use of second stage regression analysis.

119 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 54-58.

120 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 49-50.

B Operating Environmental Factors

Issues raised by Frontier Economics	Our response
Bushfire risk component of the vegetation management OEF - in summary, this OEF exists to account for the differences in opex between distributors due to differences in bushfire risk and associated differences in the regulatory obligations for clearing vegetation. In this case, between Queensland and the comparison networks, which are located in Victoria and South Australia. Our draft decision applied the approach of the 2015 decisions, which calculated a material bushfire risk OEF for Ergon Energy by quantifying the incremental effects of new regulations faced by Victorian distributors following the 2010 Black Saturday bushfires. The increased opex as a result of the new regulations was used as a proxy for the differences in the costs related to managing bushfire risk between Queensland and Victoria.	
Frontier Economics argued that vegetation management opex does not reflect just the cost associated with complying with bushfire regulations. Vegetation management is not solely to comply with bushfire regulations.[121]	We agree with Frontier Economics that vegetation management is not solely to comply with bushfire regulations. Key drivers for vegetation management opex include differences in vegetation density and growth rates, length of overhead lines as well as the adjacency of vegetation to those network assets. However, we consider that our economic benchmarking models largely account for these differences, through the inclusion of a circuit line length output variable (in combination with the share of undergrounding variable). Vegetation management requirements, beyond bushfire-specific regulations, are another driver of vegetation management opex. However, we also consider that these requirements may depend on the perceived bushfire risk. For example, the amended Victorian Electricity Safety (Electric Line Clearance) Regulations 2010 prescribe (among other things) minimum vegetation clearance spaces for power lines that become progressively stricter in areas of higher bushfire risk.[122]
Frontier Economics argued that our quantification of the impact bushfire regulations is flawed for the following reasons: 1. Lack of data on actual costs incurred by reference distributors – it is problematic to quantify the impact of higher vegetation opex of bushfire-related obligations by instead using ex ante cost allowances for these obligations approved by the AER in the 2010 Victorian decisions. This is because it is possible that the reference distributors underspent these allowances.[123] 2. Reliance on average forecast costs over the period 2011 to 2015 rather than the latest information available – Frontier Economics argues that the forecast cost varied considerably over the 2011–15 period, and thus it seems probable that the costs incurred in 2016 and later years were lower than the average.[124]	We acknowledge that under incentive regulation, distributors are provided incentives to operate efficiently. However, while it is possible that an efficient distributor has under-spent an opex allowance, experience shows it is also possible for it to over-spend as it is expected that the allowance set provides the distributor with a reasonable opportunity to recover at least the efficient costs.[125] We acknowledge limitations with the available data. However, we consider that our approach of relying on forecasts costs, as originally developed for the 2015 determinations, is appropriate and the quantification is based on the best data currently available to us. In relation to the second point, we also note that, based on our assessment in the 2010 Victorian decisions, the Victorian distributors were at that time subject to vegetation management regulations broadly similar to distributors in other states and in

121 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p. 24.

122 *Electricity Safety (Electric Line Clearance) Regulations 2010*, Schedule to the Code.

123 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 33–35.

124 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 35–36.

Issues raised by Frontier Economics	Our response
	particular NSW and QLD. Their expenditure prior to that reflects a level of regulation regarding bushfires that is therefore more likely to be comparable with distributors in other jurisdictions. The step changes relating to vegetation management for the years 2011 to 2015 are the amount of opex required to comply with the higher vegetation management standards put in place after the inquiry by the Victorian Bushfire Royal Commission. Therefore, the 2011–15 period-average amount best reflects the level of opex required to meet this higher standard.
Frontier Economics stated the AER's analysis showing Ergon Energy's vegetation management opex had declined since 2010 compared to that incurred by Victorian distributors is misleading: • The comparators in this analysis are all five Victorian distribution network service providers, but only three are benchmark comparators[126] • The difference in the vegetation management opex of the reference group of Victorian distributors relative to Ergon Energy has not been broadly consistent.[127] Frontier Economics extended the AER's analysis to compare the vegetation management opex between Ergon Energy and the three Victorian reference distributors. It argued that the gap between the reference distributors in Victoria and Ergon Energy varied over time.	We acknowledge that the reference distributors in figure A6.1 of the draft decision included all five Victorian distributors. However, based on updated analysis, we continue to find that Ergon Energy's vegetation management opex has broadly decreased over time, and that the gap with the three reference distributors in Victoria, on both total and per-km vegetation management opex bases, has not narrowed since 2012. If Ergon Energy had adopted the same type of bushfire mitigation activities introduced by the Victorian regulations in 2010, we would expect a significant increase in their vegetation management opex. Given we have not seen this, and that the gap to the three Victorian distributors has not narrowed, lends support to relying upon our 2015 approach in relation to the OEF for relative bushfire risks.
Frontier Economics disputed the AER's finding that Ergon Energy faces lower bushfire risk compared to the benchmark reference Victorian distributors. Using Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES)'s forest fires data for the period 2011–12 to 2015–16, Frontier Economics compares the number, and area, of forest fires in Queensland and Victoria. It claimed that over the period studied: • the number of unplanned fires, as well as the area affected, is many time higher in Queensland than Victoria • Ergon Energy's network overlaps with significant areas of forest, of which 24.8 per cent experienced a forest fire.[128]	In the 2015 Ergon Energy decision we stated that Victoria has the highest risk of bushfire of any State or Territory in Australia and is one of the most fire-prone areas in the world.[129] This view was informed by a range of analysis, including maps of potential bushfire zones and bushfire intensity in different regions of Australia, major bushfires in Queensland versus Victoria, past and forecast economic costs of bushfires. Our views of relatively high bushfire area in parts of Victoria and South Australia compared to Queensland have not changed after reviewing the Frontier Economics analysis, as discussed below. First, the use of the number of fires and total area burnt may overstate the intensity and severity of forest fires in Queensland relative to Victoria. As noted in ABARES's 2013 state of the forests report, in northern Australia low-intensity fires burn over large areas, while some areas in southern Australia are prone to

125 NEL, s. 7A(2).

126 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 23–24.

127 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p. 24.

128 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 26–30.

129 AER, *Final Decision, Ergon Energy determination 2015−16 to 2019−20, Attachment 7 − Operating Expenditure*, October 2015, p. 65.

Issues raised by Frontier Economics	Our response
	intensive and uncontrollable fires, resulting in huge loss of human life and community assets including power lines.[130] Second, the sample period studied in the ABARES report is relatively short, covering five years 2011–12 to 2015–16. This may not be representative of the frequency and severity of bushfires in the longer term, and thus fails to capture the underlying bushfire risk profile by region. In our view, a sufficiently long historic period needs to be covered to estimate the likelihood of bushfire occurrence and its severity, including economic and human losses, in the longer term. Updated research into the cost of disasters in Australia extends the sample period covered in the 2001 Bureau of Transport Economics (BTE) report[131] (that we cited in support of our 2015 determination and analysis) to cover the period 1967 to 2013,[132] which covers a sufficiently long historic period. The research shows that bushfires excluding heatwaves accounted for about 40 per cent of total disaster losses in Victoria in comparison to roughly 2 per cent in Queensland. Taking into account the higher economic losses associated with all disasters in Queensland ($50 billion, $2013) versus Victoria ($33 billion, $2013)) over the period, this implies that the economic losses associated with bushfires in Victoria were 13 times more than those in Queensland. In relation to Frontier Economics' analysis of Ergon Energy's network area, about 11.5 per cent of the network area defined by Frontier Economics is forest, and only 2.8 per cent has experienced fire within the five years 2011–12 to 2015–16.[133] Further, in this piece of analysis, Frontier Economics does not appear to make any distinction between the overhead lines and underground cables, or between planned fires and unplanned fires. We note both undergrounding and controlled burning could be effective bushfire risk mitigation strategies,[134] which is not captured when looking at simple percentages of network area.
Frontier Economics disputed the AER's observation that vegetation density in Ergon Energy's service area is low and comparable to the lower bushfire risk areas in north west Victoria. It contended that the AER's own consultant, Sapere-Merz, cautioned that vegetation density maps could not be used to draw conclusions about differences in growth rates within a distributor's service region.[135]	Our vegetation density analysis has referred to the Bureau Of Meteorology (BOM) vegetation density maps. The Normalised Difference Vegetation Index developed for these maps is a standardized way to measure healthy vegetation. It does this by measuring the difference between near-infrared (which vegetation strongly reflects) and red light (which vegetation absorbs), and thus provides a measure of the amount of live

130 Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), *Australia's State of the Forest Report 2013*, p. 190.

131 Bureau of Transport Economics, *Economic Costs of Natural Disasters in Australia*, Report 103, 2001.

132 Handmer, J, M. Ladds and L Magee, *Updating the Costs of Disasters in Australia*, Australian Journal of Emergency Management, 33(2), April 2018, pp. 40-46.

133 Ergon Energy, *Information request 76, 200114 – Result analysis.xlsx*, 21 January, 2020.

134 Controlled burning is a forest management tool to reduce fuel loads ad regenerate forests. In Australia, about 80 per cent of forest are eucalyptus trees.

135 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 30-32.

Issues raised by Frontier Economics	Our response
	green vegetation and its density and condition.[136] The dataset provides an overview of the status and dynamics of vegetation across Australia. We agree with Sapere-Merz that seasonal and inter-annual variations in vegetation growth may drive vegetation management opex over time, and that, therefore, vegetation density maps should be used with caution. However, for opex benchmarking, we examine efficient opex on a period-average basis, and on the basis of inspecting the Normalised Difference Vegetation Index series over the benchmarking period, we maintain that vegetation density in Ergon Energy's service area is generally low and comparable to the lower bushfire risk areas in north west Victoria. We also note that Sapere-Merz concludes that fundamental drivers of vegetation management opex such as vegetation density and growth rate may in turn be modified between jurisdictions by variations in regulated responsibilities for vegetation management, including mandated standards (notably bushfire regulations in Victoria); and vegetation management responsibility.[137] This limits the inferences that can be made from observations of vegetation density.
Network accessibility OEF - to account for the higher cost of access route maintenance (e.g. due to adverse climate and heavy rainfall) that Ergon Energy incurs compared to the reference distributors	
Frontier Economics questioned the omission of network accessibility OEF to Ergon Energy in the draft decision. In the 2015 final decision for Ergon Energy, the AER applied a material OEF adjustment of 1.1 per cent to account for the higher cost of access route maintenance that Ergon Energy incurs compared to the reference distributors at that time.[138]	We agree with Frontier Economics' observation that the network accessibility circumstances faced by Ergon Energy has likely not changed since our 2015 assessment and this should be included in our OEF assessment. We have incorporated this OEF into our adjustments in determining our alternative estimate for the final decision for Ergon Energy. We have relied on our assessment approach of network accessibility from our 2015 decision for Ergon Energy, with updated data on network without standard vehicle access up to 2018.
Occupational Health and Safety (OH&S) OEF - to account for the fact that Queensland distributors operate under more stringent OH&S regulations than do the reference Victorian distributors	
Frontier Economics claimed that Sapere-Merz misunderstood the AER's approach to quantifying the OH&S OEFs. In its view it appears that Sapere-Merz interpreted the AER's approach as using the estimated compliance costs for power generators as a measure of the compliance costs in absolute dollars that would be faced by distributors. Frontier Economics argued that this is an unjustified departure from the AER's 2015 approach, which was based on applying a *percentage* uplift to opex.[139]	All NEM jurisdictions other than Victoria have adopted harmonised Work Health and Safety (WHS) laws as part of COAG's national reform agenda in 2008.[140] In 2012 PwC estimated the cost to Victoria of adopting these laws, and this provides a basis for the current cost advantage faced by the Victorian reference businesses. Sapere-Merz examined the PwC report and outlined its finding using the information in that report of a de minimis cost per electricity generation business

136 BOM, Map information – Normalised Difference Vegetation Index, available at: http://www.bom.gov.au/climate/austmaps/about-ndvi-maps.shtml [accessed on 18 February 2020].

137 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking,* August 2018, pp. 58-59.

138 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, p. 37.

139 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 38-40.

140 See https://www.safeworkaustralia.gov.au/law-and-regulation/development-model-whs-laws .

Issues raised by Frontier Economics	Our response
	($5210 ($2011–12) which is $6052 in $2019–20). Sapere-Merz considered this OEF to be immaterial.[141] Under our preferred approach of excluding immaterial factors, no adjustment was made for OH&S differences in the draft decision. Sapere-Merz's approach differs from our approach in the 2015 decision in whether and how to adjust for industry characteristics. As a result, Sapere-Merz considered that the "previous quantification substantially over-stated the potential impact on opex."[142] While the PwC report shows limited variations in compliance costs across industry cohorts, we consider that compliance cost may go up with firm size (at a decreasing rate). We note that electricity distribution is around 50 times that of electricity generation in terms of average employment number per firm.[143] We retain the view that immateriality is robust to multiples of $6052 to take into account scale. Sapere-Merz also noted that this approach is consistent with AER decisions not to increase opex following the introduction of WHS laws in jurisdictions other than Victoria.[144]
Immaterial factors becoming material as a result of AusNet Services no longer being considered as a reference firm	
Frontier Economics raised concerns that the removal of AusNet Services as one of the reference firms since the 2015 decision will mean that some OEFs that were previously considered immaterial would now be material. It identified two factors, namely environmental variability and topography, whose materiality would have increased as a result.[145]	We note that neither Ergon Energy nor Frontier Economics has submitted any evidence or data to substantiate the arguments or to quantity the likely impact of AusNet Services' exclusion from being considered a reference business. We recognise that given the mountainous topography of AusNet Services' network, its exclusion from the set of reference businesses is likely to have increased the cost difference between the reference businesses and Ergon Energy. However, we consider that our inclusion of the network accessibility OEF for this final decision will adequately capture this impact.
AER not accounting for immaterial OEFs	

141 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking,* August 2018, p. 82.

142 Sapere-Merz*, Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p.81.

143 See IBISWorld Industry Reports: IBISWorld, *Electricity Distribution in Australia, Industry Report D2630*, March 2019, p. 12; IBISWorld, *Fossil Fuel Electricity Generation in Australia, Industry Report D2611*, May 2019, p. 9; IBISWorld, *Hydro-Electricity Generation in Australia, Industry Report D2612*, January 2020, p. 12; IBISWorld, *Wind and Other Electricity Generation in Australia, Industry Report D2619A*, February 2019, p. 10.

144 Sapere-Merz*, Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p.81.

145 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 47–48.

Issues raised by Frontier Economics	Our response
Frontier Economics considered the AER has not addressed the fact that it has previously acknowledged that the cumulative effect of individually-immaterial OEFs could be material. If that is the case (and the AER has provided no evidence to suggest otherwise), then by the AER's own analysis, the benchmarking analysis used in the draft decision may have ignored material differences in costs between distributors that are unrelated to efficiency. In the AER's 2015 decision, the AER had very little information at that time to quantify the materiality of many of the factors that it treated in that decision as immaterial. The AER has performed no work since 2015 to close those information gaps, noting that the Sapere-Merz work focused on material factors. The AER has gained no new information since 2015 that would support the exclusion of the immaterial OEFs. Therefore, it is unclear why the AER now regards only one of these measures, the application of a conservative benchmark comparison point, sufficient to address the significant uncertainty associated with estimating accurately the true relative efficiencies of distributors in Australia.[146]	We consider that these points were largely addressed in section A.4 of the draft decision. In summary, in response to the Frontier Economics report, we maintain that the move to material-only OEF factors remains justified. We consider that the Sapere-Merz review was an incremental improvement and that our benchmarking approach remains appropriately conservative, as seen in our use of the 0.75 benchmark and the use of multiple models. Our inclusion of immaterial OEFs in 2015 should be seen in the context of a conservative approach, reflecting at the time it was our first application of benchmarking (as the primary tool) to setting efficient opex. We note that our use of the 0.75 benchmark is equivalent to giving some weight to revealed opex in deriving our alternative estimate of efficient opex. We also note that, for this final decision, adopting a less conservative approach to OEF (by excluding immaterial factors) would not have changed our overall decision to accept Ergon Energy's opex proposal. As noted in our *2019 Annual Benchmarking Report*, we intend to refine and update our OEF analysis over time to ensure that the OEFs are continually improved and stay relevant.[147]

146 Frontier Economics, *Assessment of the AER's Benchmarking Analysis - A report prepared for Ergon Energy and Energex*, December 2019, pp. 41–48.

147 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. 27.

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAM	cost allocation method
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
MPFP	multilateral partial factor productivity
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
OEF	Operating Environment Factors
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RIN	regulatory information notice