



**FINAL DECISION**  
**Ergon Energy determination**  
**2015–16 to 2019–20**

**Attachment 7 – Operating**  
**expenditure**

October 2015

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## Note

This attachment forms part of the AER's final decision on Ergon Energy's 2015–20 distribution determination. It should be read with other parts of the final decision.

The final decision includes the following documents:

### Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

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## Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

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## 7 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 total revenue requirement.

This attachment provides an overview of our assessment of opex. Detailed analysis of our assessment of opex are in the following appendices:

- Appendix A - Base opex
- Appendix B - Rate of change
- Appendix C - Step changes.

### 7.1 Final decision

We are not satisfied that Ergon Energy's forecast opex proposed in its revised regulatory proposal reasonably reflects the opex criteria.<sup>1</sup> We therefore do not accept the forecast opex Ergon Energy included in its building block proposal.<sup>2</sup> We compare our substitute estimate of Ergon Energy's opex for the 2015–20 regulatory control period with Ergon Energy's initial regulatory proposal, our preliminary decision and Ergon Energy's revised regulatory proposal in Table 7.1.

**Table 7.1 Our preliminary and final decisions on total opex (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Initial regulatory proposal	349.6	356.1	363.6	372.9	379.0	1821.1
Preliminary decision	314.4	320.3	325.4	332.0	337.8	1629.9
Revised regulatory proposal	334.0	346.6	358.2	365.9	374.3	1779.0
Final decision	334.3	340.0	345.7	352.8	359.5	1732.4

Source: AER analysis.

Note: Excludes debt raising costs.

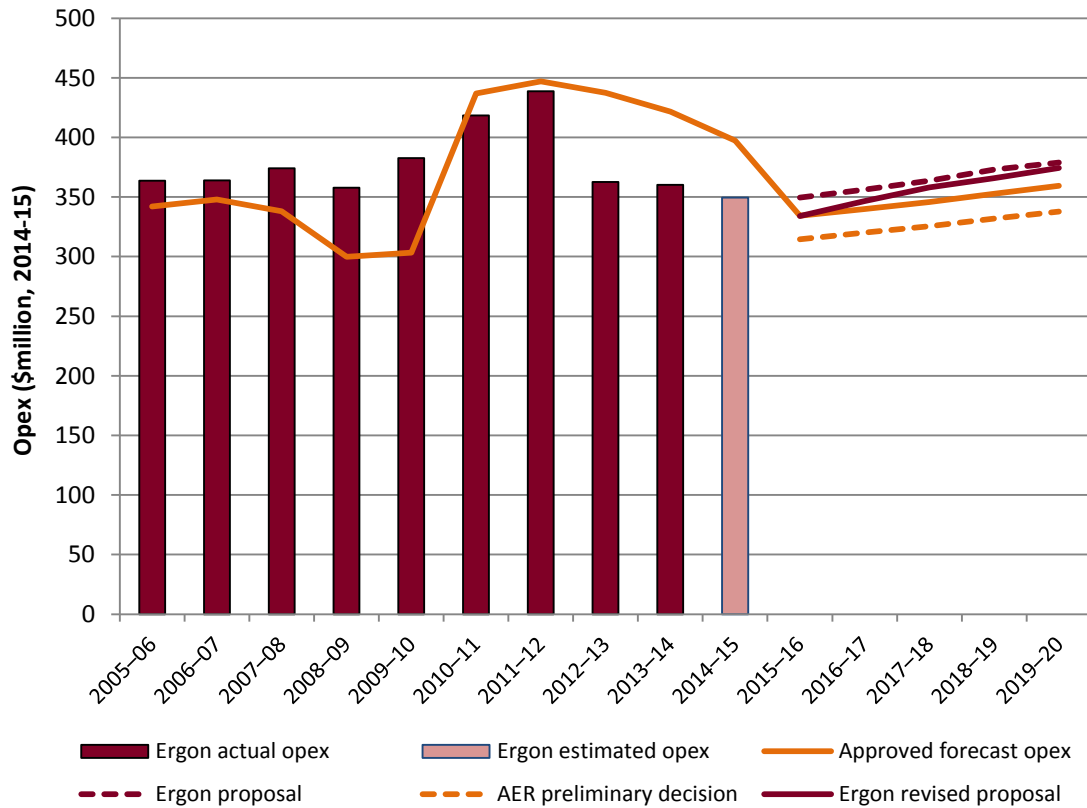
Figure 7.1 shows our preliminary and final decisions compared to Ergon Energy's past actual opex, previous regulatory decisions as well as its initial and revised regulatory proposals.

<sup>1</sup> NER, cl. 6.5.6(d).

<sup>2</sup> NER, cl. 6.5.6(d) and 6.12.1(4)(ii).



**Figure 7.1 AER final decision compared to preliminary decision and Ergon Energy's past and proposed opex**



Note: The opex for the period 2005–06 to 2014–15 include some services that have been reclassified as ancillary reference services; the forecast opex for period 2015–16 to 2019–20 does not. The opex for the period 2005–06 to 2009–10 also includes debt raising costs; the opex and forecast opex for the period 2010–11 to 2019–20 do not.

Source: Ergon Energy, Regulatory accounts 2005–06 to 2009–10; Ergon Energy 2010–11 to 2014–15 PTRM, Annual Reporting RIN 2010–11 to 2013–14, *Regulatory proposal*, *Revised regulatory proposal*; AER analysis.

We are not satisfied that Ergon Energy's proposed total forecast opex reasonably reflects the opex criteria. The difference between our substitute estimate and Ergon Energy's proposed total forecast opex primarily relate to:

- step changes
- differences in the rate of change in respect of price growth, output growth and productivity growth
- allocation of overheads
- service classification
- efficiency adjustments and
- cost allocation methodology and accounting adjustments.

One key area where we have departed from our preliminary decision is with respect to the base opex used to derive our substitute estimate of total opex. Based on updated information, we consider that Ergon Energy's revealed expenditure of \$318.9 million (\$2014–15) is an appropriate starting point for a total forecast opex that we would be satisfied reasonably reflects the opex criteria.

We set out a summary of our reasons in section 7.4 below.

## 7.2 Ergon Energy's revised regulatory proposal

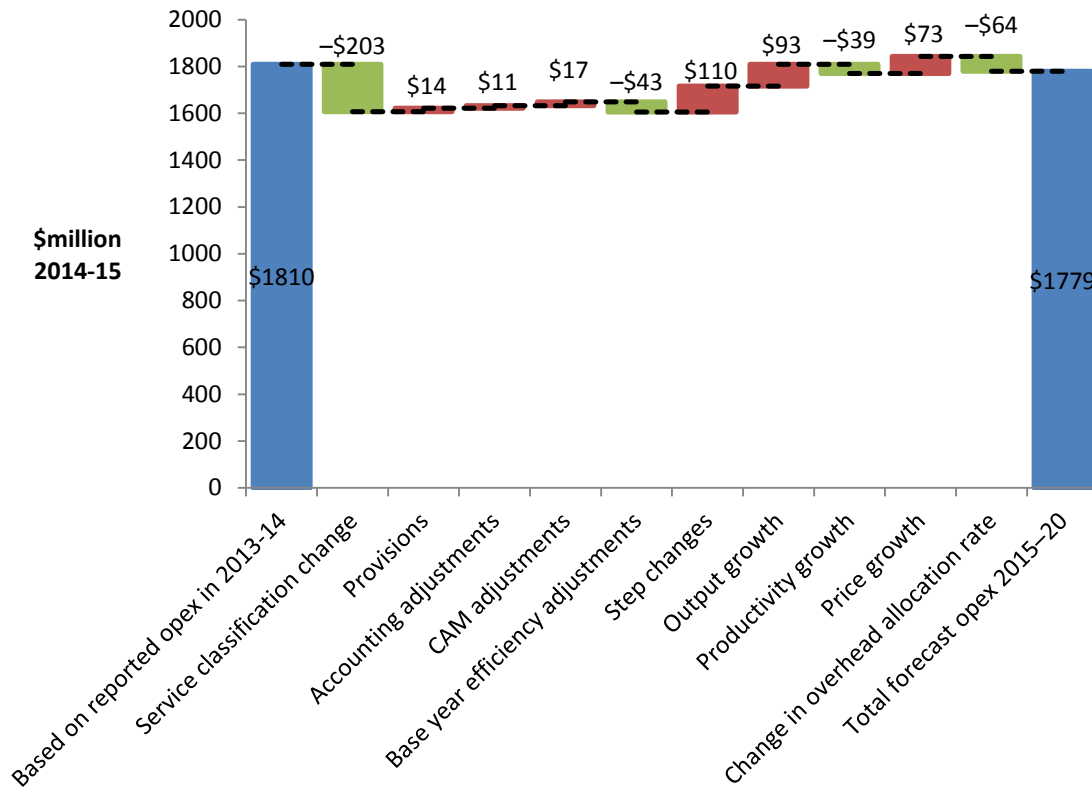
Our preliminary decision provided that a substitute opex of \$1629.9 million (\$2014–15) reasonably reflects the opex criteria. Ergon Energy did not accept our preliminary decision and revised its proposed forecast opex to \$1779.0 million (\$2014–15) for the 2015–20 regulatory control period, excluding debt raising costs.<sup>3</sup> This is a \$42.1 million or 2.3 per cent reduction on the \$1821.1 million (\$2014–15) that it proposed in its initial regulatory proposal.

In Figure 7.2 we separate Ergon Energy's forecast opex of \$1779.0 million (\$2014–15) into the different elements that make up its forecast.

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<sup>3</sup> Ergon Energy, *Revised Proposal 2015–20 (revised)*, Appendix A: *Operating expenditure forecasts for Standard Control Services*, 3 July 2015, p. 76.

**Figure 7.2 Ergon Energy's total opex forecast for the 2015–20 regulatory control period (\$ million, 2014–15)**



Source: AER analysis.

We describe each of these elements below:

- Ergon Energy used the actual opex it incurred in 2013–14 as the base for forecasting its opex for the 2015–20 regulatory control period. It forecast this would lead to base opex of \$1809.6 million (\$2014–15) over the 2015–20 regulatory control period.
- Ergon Energy adjusted its revealed expenditure base opex to remove opex on metering and connection services. These services have been reclassified as alternative control services so need to be removed from Ergon Energy's standard control services opex. This reduced Ergon Energy's forecast by \$202.5 million (\$2014–15).
- Ergon Energy accounted for movements in provisions in its base year. This increased Ergon Energy's opex forecast by \$14.1 million (\$2014–15).
- Ergon Energy made 'accounting adjustments' and 'CAM adjustments' to its 2013–14 opex. These adjustments respectively increased Ergon Energy's forecast by \$10.9 million (\$2014–15) and \$16.5 million (\$2014–15).
- Ergon Energy identified \$43.0 million (\$2014–15) in efficiency gains relative to its base year.

- Ergon Energy added \$110.0 million (\$2014–15) for step changes.<sup>4</sup>
- Ergon Energy forecast output growth would increase its opex forecast by \$93.1 million (\$2014–15).
- Ergon Energy forecast productivity growth would decrease its opex forecast by \$38.9 million (\$2014–15).
- Ergon Energy forecast price growth would increase its opex forecast by \$72.9 million (\$2014–15).
- Ergon Energy forecast that overheads allocated to opex would decrease by \$63.7 million (\$2014–15). This was due to both a decrease in total overheads and a decrease in the proportion allocated to opex.

Table 7.3 summarises the areas of difference between Ergon Energy's proposed total opex in its revised regulatory proposal and our substitute estimate.

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<sup>4</sup> This number does not include the proposed increase in ICT costs. In Ergon Energy's proposal this step change is included in the increase in capex and opex overheads.

**Table 7.2 Areas of difference between revised regulatory proposal and final decision (\$ million, 2014–15)**

	Revised regulatory proposal	Final decision	Difference
Based on revealed opex	1809.6	1792.1	-17.5
Service classification change	-202.5	-211.4	-8.9
Efficiency adjustment	-43.0	0.0	43.0
Provisions	14.1	14.1	0.0
Price change	72.9	22.9	-50.0
Productivity change	-38.9	0.0	38.9
Output change	93.1	88.4	-4.7
Step changes	110.0	26.4	-83.6
Accounting adjustments	10.9	0.0	-10.9
CAM adjustments	16.5	0.0	-16.5
Change in overheads	-63.7	0.0	63.7
<b>Total opex</b>	<b>1779.0</b>	<b>1732.4</b>	<b>-46.6</b>

Source: AER analysis.

Note: Excludes debt raising costs; Numbers may not add due to rounding.

## 7.3 Assessment approach

This section sets out our general approach to assessment.<sup>5</sup> Our approach to assessment of particular aspects of the opex forecast is set out in more detail in the relevant appendices.

Our assessment approach, outlined below, is, for the most part, consistent with the Expenditure Forecast Assessment Guideline (the Guideline).

There are two tasks that the NER requires us to undertake in assessing total forecast opex. In the first task, we form a view about whether we are satisfied a service provider's proposed total opex forecast reasonably reflects the opex criteria.<sup>6</sup> If we are satisfied, we accept the service provider's forecast.<sup>7</sup> In the second task, we determine a substitute estimate of the required total forecast opex that we are satisfied reasonably reflects the opex criteria.<sup>8</sup> We only undertake the second task if we do not accept the service provider's forecast after undertaking the first task.

In both tasks, our assessment begins with the service provider's proposal. We also develop an alternative forecast to assess the service provider's proposal at the total opex level. The alternative estimate we develop, along with our assessment of the component parts that form the total forecast opex, inform us of whether we are satisfied that the total forecast opex reasonably reflects the opex criteria.

It is important to note that we make our assessment about the total forecast opex and not about particular categories or projects in the opex forecast. The Australian Energy Market Commission (AEMC) has expressed our role in these terms:<sup>9</sup>

It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

The opex criteria that we must be satisfied a total forecast opex reasonably reflects are:<sup>10</sup>

1. the efficient costs of achieving the operating expenditure objectives
2. the costs that a prudent operator would require to achieve the operating expenditure objectives
3. a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

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<sup>5</sup> The discussion in this section, to the extent it differs from that set out in the preliminary decision, clarifies the assessment approach that we applied in both the preliminary decision and this final decision.

<sup>6</sup> NER, cl. 6.5.6(c) and 6.12.1(4).

<sup>7</sup> NER, cll. 6.5.6(c) and 6.12.1(4)(i).

<sup>8</sup> NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

<sup>9</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

<sup>10</sup> NER, cl. 6.5.6(c).

The AEMC noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.<sup>11</sup>

The service provider's forecast is intended to cover the expenditure that will be needed to achieve the opex objectives. The opex objectives are:<sup>12</sup>

1. meeting or managing the expected demand for standard control services over the regulatory control period
2. complying with all applicable regulatory obligations or requirements associated with providing standard control services
3. where there is no regulatory obligation or requirement, maintaining the quality, reliability and security of supply of standard control services and maintaining the reliability and security of the distribution system
4. maintaining the safety of the distribution system through the supply of standard control services.

Whether we are satisfied that the service provider's total forecast reasonably reflects the opex criteria is a matter for judgment. This involves us exercising discretion. However, in making this decision we treat each opex criterion objectively and as complementary.<sup>13</sup> When assessing a proposed forecast, we recognise that efficient costs are not simply the lowest sustainable costs. They are the costs that an objectively prudent service provider would require to achieve the opex objectives based on realistic expectations of demand forecasts and cost inputs. It is important to keep in mind that the costs a service provider might have actually incurred or will incur due to particular arrangements or agreements that it has committed to may not be the same as those costs that an objectively prudent service provider requires to achieve the opex objectives.

Further, in undertaking these tasks we have regard to the opex factors.<sup>14</sup> We attach different weight to different factors. This approach has been summarised by the AEMC as follows:<sup>15</sup>

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.

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<sup>11</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

<sup>12</sup> NER, cl. 6.5.6(a).

<sup>13</sup> AER, *Preliminary Decision Ergon Energy determination 2015-16 to 2019-20: Attachment 7 – Operating expenditure*, April 2015, pp. 7–74–7–76.

<sup>14</sup> NER, cll. 6.5.6(c) and (d).

<sup>15</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

The opex factors that we have regard to are:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period
- the actual and expected operating expenditure of the distribution network service provider during any preceding regulatory control periods
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the distribution network service provider in the course of its engagement with electricity consumers
- the relative prices of operating and capital inputs
- the substitution possibilities between operating and capital expenditure
- whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the distribution network service provider under clauses 6.5.8 or 6.6.2 to 6.6.4
- the extent the operating expenditure forecast is referable to arrangements with a person other than the distribution network service provider that, in our opinion, do not reflect arm's length terms
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)
- the extent to which the distribution network service provider has considered and made provision for efficient and prudent non-network alternatives
- any relevant final project assessment conclusions report published under 5.17.4(o),(p) or (s)
- any other factor we consider relevant and which we have notified the distribution network service provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.

Consistent with our Guideline, we have used benchmarking to a greater extent than we did in regulatory determinations prior to the AEMC's 2012 rule changes. To that end, there are two additional operating expenditure factors that we have taken into account under the last opex factor above:

- our benchmarking data sets including, but not necessarily limited to:
    - (a) data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN
    - (b) any relevant data from international sources
    - (c) data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the Guideline
- as updated from time to time.



- economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.<sup>16</sup>

For transparency and ease of reference, we have included a summary of how we have had regard to each of the opex factors in our assessment at the end of this attachment.

As we noted above, the two tasks that the NER requires us to undertake involve us exercising our discretion. In exercising discretion, the National Electricity Law (NEL) requires us to take into account the revenue and pricing principles (RPPs).<sup>17</sup> In the overview we discussed how we generally have taken into account the RPPs in making this final decision. Our assessment approach to forecast opex ensures that the amount of forecast opex that we are satisfied reasonably reflects the opex criteria is an amount that provides the service provider with a reasonable opportunity to recover at least its efficient costs.<sup>18</sup> By us taking into account the relevant capex/opex trade-offs, our assessment approach also ensures that the service provider faces the appropriate incentives to promote efficient investment in and provision and use of the network and minimises the costs and risks associated with the potential for under and over investment and utilisation of the network.<sup>19</sup>

## Expenditure forecast assessment guideline

After conducting an extensive consultation process with service providers, users, consumers and other interested stakeholders, we issued the Expenditure Forecast Assessment Guideline in November 2013 together with an explanatory statement.<sup>20</sup> The Guideline sets out our intended approach to assessing opex in accordance with the NER.<sup>21</sup>

While the Guideline provides for regulatory transparency and predictability, it is not binding. We may depart from the approach set out in the Guideline but we must give reasons for doing so.<sup>22</sup> For the most part, we have not departed from the approach set out in the Guideline in this final decision.<sup>23</sup> In our framework and approach (F&A)

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<sup>16</sup> This is consistent with the approach we outlined in the explanatory statement to our Expenditure Assessment Guideline. See, for example, p. 131.

<sup>17</sup> NEL, ss. 7A and 16(2).

<sup>18</sup> NEL, s. 7A(2).

<sup>19</sup> That is, the trade-offs that may arise having considered the substitution possibilities between opex and capex, and the relative prices of operating and capital inputs: NER, cl. 6.5.6(e)(6) and 6.5.6(e)(7); NEL, ss. 7A(3), 7A(6) and 7A(7).

<sup>20</sup> AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

<sup>21</sup> NER, cl. 6.5.6.

<sup>22</sup> NER, cl.6.2.8(c).

<sup>23</sup> We did not apply the DEA benchmarking technique. We outline the reasons why we did not apply this technique in Appendix A of our preliminary decision. We also have not applied the equation for estimating final year opex. We outline why we have not made this assumption in Appendix B of our preliminary decision.

paper, we set out our intention to apply the Guideline approach in making this determination.<sup>24</sup> There are several parts of our assessment:

1. We develop an alternative estimate to assess a service provider's proposal at the total opex level.<sup>25</sup> We recognise that a service provider may be able to adequately explain any differences between its forecast and our estimate. We take into account any such explanations on a case by case basis using our judgment, analysis and stakeholder submissions.
2. We assess whether the service provider's forecasting method, assumptions, inputs and models are reasonable, and assess the service provider's explanation of how its method results in a prudent and efficient forecast.
3. We assess the service provider's proposed base year opex, step changes and rate of change if the service provider has adopted this methodology to forecast its opex.

Each of these assessments informs our first task. Namely, whether we are satisfied that the service provider's proposal reasonably reflects the opex criteria.

If we are not satisfied with the service provider's proposal, we approach our second task by using our alternative estimate as our substitute estimate. This approach was expressly endorsed by the AEMC in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:<sup>26</sup>

While the AER must form a view as to whether a NSP's proposal is reasonable, this is not a separate exercise from determining an appropriate substitute in the event the AER decides the proposal is not reasonable. For example, benchmarking the NSP against others will provide an indication of both whether the proposal is reasonable and what a substitute should be. Both the consideration of "reasonable" and the determination of the substitute must be in respect of the total for capex and opex.

We recognise that our alternative estimate may not exactly match the service provider's forecast. The service provider may have adopted a different forecasting method. However, if the service provider's inputs and assumptions are reasonable and efficient, we expect that its method should produce a forecast consistent with our estimate. We discuss below how we develop our alternative estimate.

## **Building an alternative estimate of total forecast opex**

The method we use to develop our alternative estimate involves five key steps. We outline these steps below in figure 7.3.

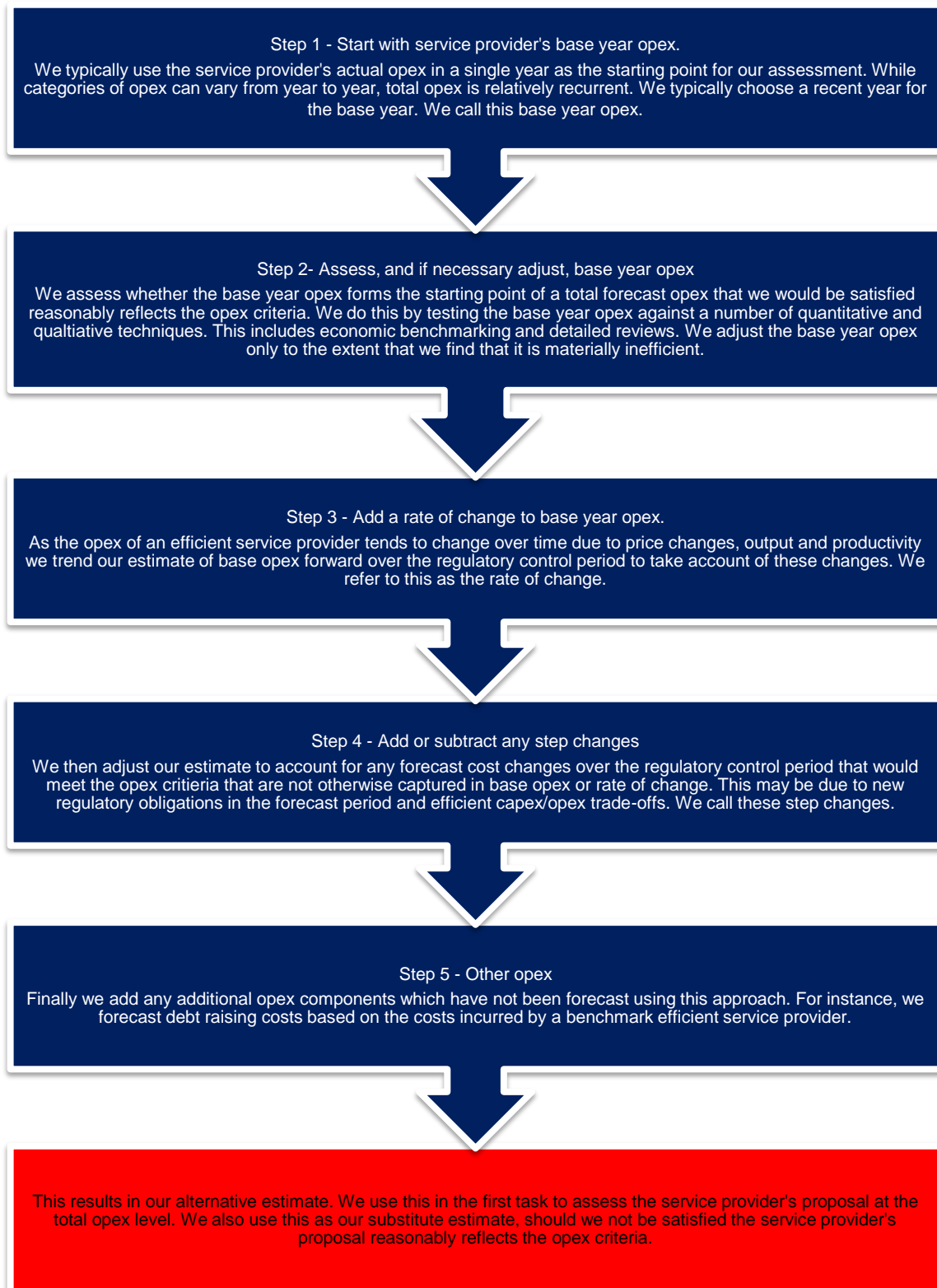
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<sup>24</sup> AER, *Stage 2 Framework and approach - NSW electricity distribution network service providers*, January 2014, p. 50.

<sup>25</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

<sup>26</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 112.

**Figure 7.3 How we build our alternative estimate**



Underlying our approach are two general assumptions:

1. the efficiency criterion and the prudence criterion in the NER are complementary

2. actual operating expenditure was sufficient to achieve the opex objectives in the past.

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model that has been employed by a number of Australian regulators over the last fifteen years. We refer to it as a 'revealed cost method' in the Guideline (and we have sometimes referred to it as the base-step-trend method in our past regulatory decisions).<sup>27</sup>

While these general steps are consistent with our past determinations, we have adopted a significant change in how we give effect to this approach, following the major changes to the NER made in November 2012. Those changes placed significant new emphasis on the use of benchmarking in our opex analysis. We will now issue benchmarking reports annually and have regard to those reports. These benchmarking reports provide us with one of a number of inputs for determining forecast opex.

We have set out more detail about each of the steps we follow in developing our alternative estimate below.

### ***Step 1 – Base year choice***

The starting point for our analysis is to use a recent year for which audited figures are available as the starting point for our analysis. We call this the base year. This is for a number of reasons:

- As total opex tends to be relatively recurrent, total opex in a recent year typically best reflects a service provider's current circumstances.
- During the past regulatory control period, there are incentives in place to reward the service provider for making efficiency improvements by allowing it to retain a portion of the efficiency savings it makes. Similarly, the incentive regime works to penalise the service provider when it is relatively less efficient. This provides confidence that the service provider did not spend more in the proposed base year to try to inflate its opex forecast for the next regulatory control period.
- Service providers also face many regulatory obligations in delivering services to consumers. These regulatory obligations ensure that the financial incentives a service provider faces to reduce its costs are balanced by obligations to deliver services safely and reliably. In general, this gives us confidence that recent historical opex will be at least enough to achieve the opex objectives.

In choosing a base year, we need to make a decision as to whether any categories of opex incurred in the base year should be removed. For instance:

- If a material cost was incurred in the base year that is unrepresentative of a service provider's future opex we may remove it from the base year in undertaking our assessment.

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<sup>27</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

- Rather than use all of the opex that a service provider incurs in the base year, service providers also often forecast specific categories of opex using different methods. We must also assess these methods in deciding what the starting point should be. If we agree that these categories of opex should be assessed differently, we will also remove them from the base year.

As part of this step we also need to consider any interactions with the incentive scheme for opex, the Efficiency Benefit Sharing Scheme (EBSS). The EBSS is designed to achieve a fair sharing of efficiency gains and losses between a service provider and its consumers. Under the EBSS, service providers receive a financial reward for reducing their costs in the regulatory control period and a financial penalty for increasing their costs. The benefits of a reduction in opex flow through to consumers as long as base year opex is no higher than the opex incurred in that year. Similarly, the costs of an increase in opex flow through to consumers if base year opex is no lower than the opex incurred in that year. If the starting point is not consistent with the EBSS, service providers could be excessively rewarded for efficiency gains or excessively penalised for efficiency losses in the prior regulatory control period.

### ***Step 2 – Assessing base year expenditure***

The service provider's actual expenditure in the base year may not form the starting point of a total forecast opex that we are satisfied reasonably reflects the opex criteria. For example, it may not be efficient or management may not have acted prudently in its governance and decision-making processes. We must therefore test the actual expenditure in the base year.

As we set out in the Guideline, to assess the service provider's actual expenditure, we use a number of different qualitative and quantitative techniques.<sup>28</sup> This includes benchmarking and detailed reviews.

Benchmarking is particularly important in comparing the relative efficiency of different service providers. The AEMC highlighted the importance of benchmarking in its changes to the NER in November 2012.<sup>29</sup>

The Commission views benchmarking as an important exercise in assessing the efficiency of a NSP and informing the determination of the appropriate capex or opex allowance.

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. For this decision we have used multilateral total factor productivity, partial factor productivity measures and several opex cost function models.<sup>30</sup>

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<sup>28</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

<sup>29</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 97.

<sup>30</sup> The benchmarking models are discussed in detail in appendix A.

We also have regard to trends in total opex and category specific data to construct category benchmarks to inform our assessment of the base year expenditure. In particular, we can use this category analysis data to identify sources of spending that are unlikely to reflect the opex criteria over the forecast period. It may also lend support to, or identify potential inconsistencies with, the results of our broader benchmarking.

If we find that a service provider's base year expenditure is materially inefficient, the question arises about whether we would be satisfied that a total forecast opex predicated upon that expenditure reasonably reflects the opex criteria. Should this be the case, for the purposes of forming our starting point for our alternative estimate, we will adjust the base year expenditure to remove any material inefficiency.

### ***Step 3 – Rate of change***

We also assess an annual escalator that is applied to take account of the likely ongoing changes to opex over the forecast regulatory control period. Opex that reflects the opex criteria in the forecast regulatory control period could reasonably differ from the starting point due to changes in:

- price growth
- output growth
- productivity growth.

We estimate the change by adding expected changes in prices (such as the price of labour and materials) and outputs (such as changes in customer numbers and demand for electricity). We then incorporate reasonable estimates of changes in productivity.

### ***Step 4 – Step changes***

Next we consider if any other opex is required to achieve the opex objectives in the forecast period. We refer to these as 'step changes'. Step changes may be for cost drivers such as new, changed or removed regulatory obligations, or efficient capex/opex trade-offs. As the Guideline explains, we will typically include a step change only if efficient base year opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.<sup>31</sup>

### ***Step 5 – Other costs that are not included in the base year***

In our final step, we assess the need to make any further adjustments to our opex forecast. For instance, our approach is to forecast debt raising costs based on a benchmarking approach rather than a service provider's actual costs. This is to be consistent with the forecast of the cost of debt in the rate of return building block.

After applying these five steps, we arrive at our alternative estimate.

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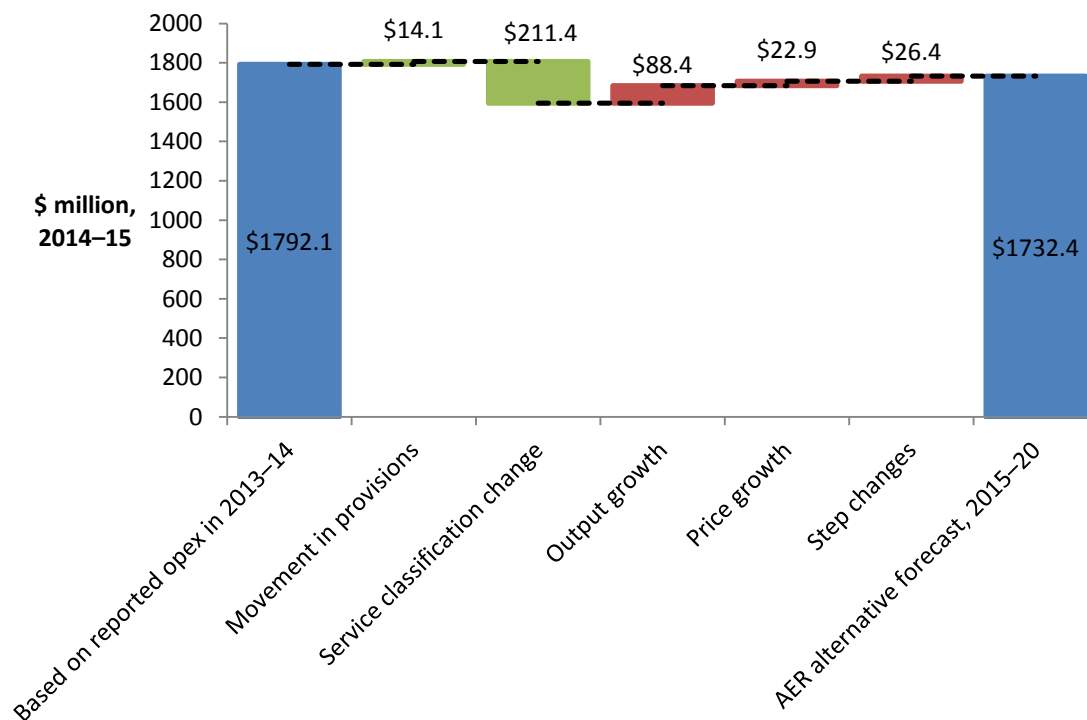
<sup>31</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

## 7.4 Summary of our decision

We are not satisfied that Ergon Energy's proposed total forecast opex of \$1779.0 million (\$2014–15) reasonably reflects the opex criteria.<sup>32</sup> As we discussed above, we have therefore used our alternative estimate as our substitute estimate.<sup>33</sup>

Figure 7.4 illustrates how we constructed our alternative estimate. The starting point on the left is what Ergon Energy's opex would have been for the 2015–20 regulatory control period if it was set based on Ergon Energy's reported opex in 2013–14.

**Figure 7.4 AER final decision opex forecast for the 2015–20 regulatory control period**



Source: AER analysis.

Table 7.3 summarises the difference between Ergon Energy's proposed total opex in its revised regulatory proposal and our substitute estimate in this final decision.

<sup>32</sup> NER, cl. 6.5.6(d).

<sup>33</sup> NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

**Table 7.3 Revised regulatory proposal and final decision total forecast opex (\$ million, 2014–15)**

	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Revised regulatory proposal	334.0	346.6	358.2	365.9	374.3	1779.0
Final decision	334.3	340.0	345.7	352.8	359.5	1732.4
<b>Difference between revised regulatory proposal and final decision</b>	<b>0.3</b>	<b>-6.6</b>	<b>-12.5</b>	<b>-13.1</b>	<b>-14.8</b>	<b>-46.6</b>

Source: AER analysis.

Note: Excludes debt raising costs.

We outline the key areas of difference between our substitute estimate and Ergon Energy's forecast below.

### 7.4.1 Forecasting method assessment

Ergon Energy used the same forecasting method to forecast opex for its revised proposal as it did for its initial proposal.

In appendix D of our preliminary decision, we set out our consideration of Ergon Energy's forecasting methodology in determining our alternative estimate opex for the 2015–20 regulatory control period. Having considered the differences between the method set out in the Guideline and Ergon Energy's method, we are satisfied that the guideline forecasting method produces an opex forecast that reasonably reflects the opex criteria. We formed our alternative estimate of total opex using the guideline forecasting method with all Ergon Energy's opex categories other than debt raising costs included in base opex.

### 7.4.2 Base opex

We have forecast a base opex amount for 2013–14 of \$318.9 million (\$ 2014–15). Our forecast of base opex is outlined in Table 7.4.

**Table 7.4 AER forecast of base opex (million, \$2014–15)**

	Final decision
Reported 2013–14 opex	486.6
Remove debt raising costs	-4.5
Remove movement in provisions	2.8
Remove feed-in tariff payments	-123.7
Service classification adjustment	-42.3
Base opex	318.9

Source: AER analysis.



Note: Ergon Energy made 'accounting adjustments' and 'CAM adjustments' to its 2013–14 opex. These adjustments respectively increased Ergon Energy's forecast by \$10.9 million (\$2014–15) and \$16.5 million (\$2014–15). We have not made these adjustments because Ergon Energy did not describe the nature of, or the reasons for, these adjustments in its revised regulatory proposal.

We have departed from our preliminary decision base year opex position in this final decision. Our final position is that Ergon Energy's revealed expenditure of \$319 million (\$2014–15) is an appropriate starting point for a total forecast opex that we are satisfied reasonably reflects the opex criteria. We have not found material inefficiency in Ergon Energy's revealed expenditure. There are two main reasons for our final position.

First, based on our assessment of updated information, we have adjusted the efficiency score that we have assessed Ergon Energy's proposed base year opex against by:

- removing \$30.5 million (\$2012–13) of metering opex that was incorrectly included by Ergon Energy in its networks services opex in its initial regulatory proposal
- using non-coincident maximum demand data consistently for Australia, New Zealand and Ontario in the econometric benchmarking models
- increasing the operating environment factor (OEF) adjustments that we have applied for cyclones and OH&S obligations by 1.8 per cent, increasing the total OEF adjustment from 24.4 to 26.2 per cent.

Ergon Energy's revealed expenditure is 2.8 per cent less than our estimate of Ergon Energy's base year opex.

Second, despite Ergon Energy facing a more challenging operating environment than Ausgrid, Essential Energy and ActewAGL (based on the differences in the amount of OEF adjustments that we have applied), Ergon Energy's efficiency has improved over the last two years. Ergon Energy has reduced the actual opex it has incurred from around \$439 million (\$2014–15) in 2011–12 to around \$363 million in (\$2014–15) in 2012–13 and \$360 million (\$2014–15) in 2013–14. This is also consistent with the findings of Deloitte Access Economics (DAE) that since the 2012 Independent Review Panel on Network Costs published its findings, the Efficiency and Effectiveness program that Ergon Energy has implemented has significantly improved its efficiency.

When compared to service providers in other jurisdictions, Ergon Energy's revealed expenditure is likely to contain some inefficiency. DAE's findings on Ergon Energy's labour and information communications and technology costs and the results of the other techniques we have applied to test Ergon Energy's base year opex suggests this to be the case. However, as we have stated in our Guideline, our preference is to rely on Ergon Energy's revealed expenditure and to only make an adjustment where it is materially inefficient. As we stated above, to the extent any inefficiency remains, it is not sufficiently material to warrant an adjustment.

We have also considered in detail the submissions that we received that advocated for us to use a benchmark comparison point at or closer to the efficient frontier for our

Cobb Douglas Stochastic Frontier Analysis model. However, having regard to previous advice we received from Economic Insights and balancing a number of competing considerations, we are of the view that using a benchmark comparison point of 0.77 remains appropriate.

Ergon Energy's revealed expenditure is therefore an appropriate starting point for us to determine our substitute estimate of the required total forecast opex for the 2015–20 regulatory control period.

Our detailed assessment of base opex is outlined in appendix A to this attachment.

### 7.4.3 Rate of change

The efficient level of expenditure required by Ergon Energy in the 2015–20 regulatory control period may differ from that required in the final year of the 2010–15 regulatory control period. Once we have determined the opex required in the final year of the of the 2010–15 regulatory control period we apply a forecast annual rate of change to forecast opex for the 2015–20 regulatory control period.

Our forecast of the overall rate of change used to derive our alternative estimate is lower than Ergon Energy's over the 2015–20 regulatory control period. Table 7.5 below compares Ergon Energy's and our overall rate of change in percentage terms for the 2015–20 regulatory control period.

**Table 7.5 Forecast annual rate of change in opex (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
Initial regulatory proposal		1.43	1.52	1.54	1.51	1.58
Preliminary decision	0.50	1.35	1.86	1.59	2.05	1.76
Revised regulatory proposal	2.26	1.38	1.37	1.22	1.19	1.35
Final decision	1.60	1.53	1.74	1.69	2.10	1.92
<b>Difference between revised regulatory proposal and final decision</b>	<b>-0.65</b>	<b>0.16</b>	<b>0.38</b>	<b>0.46</b>	<b>0.92</b>	<b>0.57</b>

Source: AER analysis.

We have updated our estimate of the rate of change in this final decision to:

- reflect the most recent forecasts of wage growth in the Queensland utilities industry from DAE and PricewaterhouseCoopers
- remove an outlier in 2015–16 customer growth numbers due to a transition from historical to forecast data
- update our output growth forecast to reflect updated maximum demand data provided by Ergon Energy.

The net impact of these changes results in an average annual rate of change from 2014–15 to 2019–20 of 1.76 per cent. This is 0.25 per cent higher than the rate of

change we arrived at in the preliminary decision. In cumulative terms, there is no material difference between Ergon Energy's and our overall rate of change estimate over the 2015–20 regulatory control period.

The factors that drive the difference between our forecast rate of change and Ergon Energy's are the same as what we found in reaching our preliminary decision. Namely:

1. Ergon Energy's forecast of price growth is higher than ours due to its approach to labour price growth forecasting. Ergon Energy forecast labour price increase using the average weekly ordinary time earnings (AWOTE) methodology. We consider this is not the best methodology available to forecast labour price increases. We have instead applied an average of wage price increase (WPI) forecasts of the Queensland utilities sector from PriceWaterhouseCoopers and DAE. We consider this is the best possible forecast of labour price increases in the Queensland utilities sector available. In forecasting its labour price increases, Ergon Energy also assigns a greater weight to internal labour than we do.
2. Ergon Energy's forecast of productivity growth includes forecast improvements in its productivity. We have forecast productivity growth of zero. Our forecast is based on the short to medium term productivity outlook for a benchmark distribution service provider.

Our detailed assessment of the rate of change is outlined in appendix B to this attachment.

#### **7.4.4 Step changes**

We have included one step change for the market transaction centre in our alternative forecast. This follows from the decision of the Queensland Competition Authority that from 1 July 2016 the minimalist transitioning approach under the Electricity Distribution Network Code concerning the processing of information requests from retailers will no longer apply to Ergon Energy.

We are not satisfied that adding step changes for the other cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.

A summary of the costs we assessed as step changes and our preliminary position is outlined in Table 7.6.

**Table 7.6 AER assessment of step changes (\$ million, 2014–15)**

Step change	Initial regulatory proposal	Preliminary decision	Revised regulatory proposal	Final decision
Non-network ICT	53.7 <sup>34</sup>	–	82.2 <sup>a</sup>	–
Non-network alternatives (demand management)	18.4	–	–	–
Parametric insurance	65.9 <sup>b</sup>	–	65.9 <sup>b</sup>	–
Remediation of contaminated land	6.3	–	–	–
Regulatory reset costs	6.3	–	–	–
Overheads allocated to opex <sup>35</sup>	26.3	–	–63.7 <sup>c</sup>	–
Market transaction centre (new)	–	–	26.3	26.3

Source: Ergon Energy, *Regulatory proposal*; Ergon Energy, *Revised regulatory proposal, 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs, p. 13*. AER estimates.

Note: (a) Ergon Energy forecast these costs using a different base year to the one it used in its original proposal, so the forecasts are not directly comparable. Only a portion of these non-network ICT cost is allocated to standard control services opex. The difference between the initial proposal and revised proposal is due to Ergon Energy incorporating the incremental cost of its category specific forecast in this step change. It was previously included in a separate part of its proposal.

(b) Ergon Energy proposed \$65 million (\$2013–14). We adjusted to \$2014–15.

(c) Ergon Energy forecast total overhead costs using a different base year to the one it used in its original proposal, so the forecasts are not directly comparable. This is the amount the total opex forecast decreases because Ergon Energy applied a category specific forecasting approach to overheads.

Our detailed assessment of all step changes is outlined in appendix C to this attachment.

### 7.4.5 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. We forecast them using our standard forecasting approach for this category which sets the forecast equal to the costs incurred by a benchmark firm. Our assessment approach and the reasons for those forecasts are set out in the debt and equity raising costs appendix in the rate of return attachment.

<sup>34</sup> We note non-network ICT is an overhead and only a portion of this is allocated to standard control opex. Ergon Energy did not identify the allocation of this step change to opex. This amount represents the total cost of the overhead rather than the opex for standard control services.

<sup>35</sup> This is the increase in overheads attributable to the application of the cost allocation method rather than to the change in the level of total overheads. Total overheads are allocated between opex, capex and alternative control services. The increase is the result of changing the base year from 2012–13 to 2013–14.

## 7.4.6 Interrelationships

In assessing Ergon Energy's total forecast opex we took into account other components of its regulatory proposal, including:

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance forecast maximum demand affects forecast augmentation capex and forecast output growth used in estimating 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.
- changes to the classification of services from standard control services to alternative control services.
- consistency with the application of incentive schemes - because the total forecast opex that we are satisfied reasonably reflects the opex criteria is based on Ergon Energy's 2013–14 revealed expenditure, the EBSS will be applied to Ergon Energy during the 2015–20 regulatory control period.
- concerns of electricity consumers identified in the course of Ergon Energy's engagement with consumers.

## 7.4.7 Assessment of opex factors

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.<sup>36</sup> Table 7.7 summarises how we have taken the opex factors into account in making this final decision.

**Table 7.7 AER consideration of opex factors**

Opex factor	Consideration
<p>The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.</p>	<p>There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider.</p> <p>The second element, that is, the benchmark operating expenditure that would be incurred by an efficient service provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by an efficient provider for that particular network over the relevant period.</p> <p>We have used several assessment techniques that enable us to assess whether a service provider's proposed base year opex is</p>

<sup>36</sup> NER, cl. 6.5.6(e).

Opex factor	Consideration
	<p>able to form the starting point of a total forecast opex that we would be satisfied reasonably reflects the opex criteria. These techniques include economic benchmarking, opex cost function modelling, PPIs, category analysis and a detailed review of Ergon Energy's labour and workforce practices.</p>
<p>The actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods.</p>	<p>Our forecasting approach uses the service provider's actual opex as the starting point. We have compared several years of Ergon Energy's actual past opex with that of other service providers to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.</p>
<p>The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.</p>	<p>We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.<sup>37</sup></p> <p>We have considered the concerns of electricity consumers as identified by Ergon Energy – particularly those expressed in the engagement program overview provided as an attachment to its regulatory proposal. For example, a clear theme present in this document is that customers consider that electricity has become less affordable.<sup>38</sup></p>
<p>The relative prices of capital and operating inputs</p>	<p>We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks with in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.</p>
<p>The substitution possibilities between operating and capital expenditure.</p>	<p>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.</p> <p>In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.</p> <p>We also had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs.</p> <p>Further, we considered the different capitalisation practices of service providers and how this may affect opex performance under benchmarking.</p>
<p>Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.</p>	<p>The incentive scheme that applied to Ergon Energy's opex in the 2010–15 regulatory control period, the EBSS, will be again applied in the 2015–20 regulatory control period. This is because the total forecast opex that we are satisfied reasonably reflects the opex criteria is based on Ergon Energy's 2013–14 revealed expenditure.</p>

<sup>37</sup> AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

<sup>38</sup> Ergon Energy, *Regulatory Proposal: Attachment to Regulatory Proposal*, 0A.01.04, 31 October 2014 p. 2.

Opex factor	Consideration
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our preliminary decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	We have not found this factor to be significant in reaching our final decision.

Source: AER analysis.

The NER require that we notify the service provider in writing of any other factor we identify as relevant to our assessment, prior to the service provider submitting its revised regulatory proposal.<sup>39</sup> Table 7.8 identifies these factors.

**Table 7.8 Other factors we have had regard to**

Opex factor	Consideration
Our benchmarking data sets, including, but not necessarily limited to: <ul style="list-style-type: none"> <li>data contained in any economic benchmarking RIN, category analysis RIN, reset RIN or annual reporting RIN</li> <li>any relevant data from international sources</li> <li>data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the Guideline</li> </ul> as updated from time to time.	This information may potentially fall within opex factor (4). However, for absolute clarity, we are using data we gather from NEM service providers, and data from service providers in other countries to provide insight into the benchmark operating expenditure that would be incurred by an efficient and prudent distribution network service provider over the relevant regulatory period.
Economic benchmarking techniques for assessing benchmark efficient expenditure including stochastic frontier analysis and regressions utilising functional forms such as Cobb Douglas and Translog.	This information may potentially fall within opex factor (4). For clarity, and consistent with our approach to assessment set out in the Guideline, we have regard to a range of assessment techniques to provide insight into the benchmark operating expenditure that an efficient and prudent service provider would incur over the relevant regulatory control period.

Source: AER analysis.

<sup>39</sup> NER, cl. 6.5.6(e)(12).

## A Base year opex

In this appendix, we present our detailed analysis of Ergon Energy's base year opex. This follows our consideration of Ergon Energy's revised regulatory proposal and the submissions we received in response to our preliminary decision.

Base year opex is the starting point for our approach to determining an estimate of total forecast opex, which we use to determine whether – at the total level – we are satisfied Ergon Energy's proposed forecast opex for the 2015–20 regulatory control period reasonably reflects the opex criteria. If the base year opex includes material inefficiencies, it follows that total forecast opex constructed using the base, step and trend approach will reflect those inefficiencies as well. This is relevant to whether we would be satisfied that forecast reasonably reflects the opex criteria.

If we are not satisfied that the total proposed forecast opex reasonably reflects the opex criteria, we must not accept that forecast. Instead, we must determine a substitute estimate of the total required forecast opex that we are satisfied reasonably reflects the opex criteria.<sup>40</sup> In the first instance, this requires us to determine the level of base year opex that we are satisfied would form the starting point for our substitute estimate. Generally, we do this by adjusting the distributor's proposed base year opex by the extent to which we find it is materially inefficient.

The structure of this appendix is:

- section A.1 sets out our position in this final decision
- section A.2 summarises Ergon Energy's base year opex as proposed in its revised regulatory proposal and the submissions we received to our preliminary decision
- sections A.3, A.4, A.5 and A.6 sets out our reasons for our substitute decision and our assessment of the issues raised in Ergon Energy's revised regulatory proposal and the relevant submissions we received.

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<sup>40</sup> NER, cl. 6.5.6(c) and (d) and 6.12.1(4).



## A.1 Final decision

As we discuss in attachment 7, we are not satisfied that Ergon Energy's total proposed forecast opex for the 2015–20 regulatory control period reasonably reflects the opex criteria. This is the same conclusion that we reached in our preliminary decision.

However, unlike in the preliminary decision, our reasons in this final decision do not arise because of Ergon Energy's revealed expenditure. In the preliminary decision, we considered that Ergon Energy's revealed expenditure of \$341.1 million (\$2013–14) was not an appropriate starting point for a total forecast opex that we were satisfied reasonably reflects the opex criteria.<sup>41</sup> Instead, we considered that \$304.6 million (\$2013–14) was an appropriate starting point (preliminary decision base year opex position).<sup>42</sup>

We have departed from our preliminary decision base year opex position in this final decision. As we discuss below, our final position is that Ergon Energy's revealed expenditure of \$319 million (\$2014–15) is an appropriate starting point for a total forecast opex that we are satisfied reasonably reflects the opex criteria.<sup>43</sup> Based on the information before us, we have not found material inefficiency in Ergon Energy's revealed expenditure.<sup>44</sup>

Our final position follows a review of all the material before us. This includes our own analysis, Ergon Energy's revised regulatory proposal and the submissions we received in response to our preliminary decision. There are two main reasons for our final position.

First, based on our assessment of updated information, we have adjusted the efficiency score that we have assessed Ergon Energy's proposed base year opex against. We have adjusted it by:

- removing \$30.5 million (\$2014–15) of metering opex that was incorrectly included by Ergon Energy in its network services opex
- using non-coincident maximum demand data consistently for Australia, New Zealand and Ontario in the econometric benchmarking models
- increasing the total operating environment factor (OEF) adjustments that we have applied from 24.4 to 26.2 per cent by increasing the OEF adjustments for cyclones and OH&S obligations by 1.8 per cent.

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<sup>41</sup> AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 – Operating expenditure*, April 2015, pp. 7–45.

<sup>42</sup> AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 – Operating expenditure*, April 2015, pp. 7–45.

<sup>43</sup> Ergon Energy's regulatory accounts reported base year opex of \$422.1 million in nominal terms. As we did in the preliminary decision, we adjusted this figure to remove debt raising costs, solar feed-in tariff payments, service classification changes and inflation. This is because the base year opex of other service providers does not include these costs. See table A.3 below.

<sup>44</sup> NER, cl. 6.5.6(c), 6.5.6(d) and 6.12.1(4)(ii).

Ergon Energy's revealed expenditure is 2.8 per cent less than our estimate of its base year opex in this final decision.

Second, although Ergon Energy faces a more challenging operating environment than Ausgrid, Essential Energy and ActewAGL (based on the differences in the OEF adjustments that we have applied), its efficiency has improved over the last two years.<sup>45</sup> Ergon Energy has reduced the actual opex it has incurred from around \$439 million (\$2014–15) in 2011–12 to around \$363 million (\$2014–15) in 2012–13. In 2013–14 Ergon Energy further reduced its actual opex to around \$360 million (\$2014–15). This is consistent with the findings of Deloitte Access Economics (DAE) that since the 2012 Independent Review Panel on Network Costs (IRP) published its findings, the Efficiency and Effectiveness program that Ergon Energy implemented has improved its efficiency.<sup>46</sup>

Nevertheless, some inefficiency is likely to remain in Ergon Energy's revealed expenditure. DAE's findings on Ergon Energy's labour and information communications and technology costs and the results of the other techniques we have applied to test Ergon Energy's base year opex supports this. However, as we have stated in our Guideline, our preference is to rely on Ergon Energy's revealed expenditure and to only make an adjustment where it is materially inefficient. In Ergon Energy's case, to the extent any inefficiency remains, we have not found it to be material. This is particularly so in light of the incentives imposed upon Ergon Energy through the operation of the efficiency benefit sharing scheme (EBSS) and our continued use of benchmarking.

We have also considered in detail the submissions that we received that advocated for us to use a benchmark comparison point closer to the efficient frontier of our Cobb Douglas Stochastic Frontier Analysis (CD SFA) model. However, we remain of the view that the position we arrived in the preliminary decision to use a benchmark comparison point of 0.77.

Ergon Energy's revealed expenditure is therefore an appropriate starting point for us to determine our substitute estimate of the required total forecast opex for the 2015–20 regulatory control period.<sup>47</sup>

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<sup>45</sup> For example, this is demonstrated by us only applying a 0.5 per cent OEF adjustment for extreme weather events (as part of the individually immaterial OEF adjustments we applied) in the case of Ausgrid, Endeavour Energy and Essential Energy: AER, *Final Decision: Ausgrid distribution determination 2015–16 to 2018–19, Attachment 7 – Operating expenditure*, April 2015, p. 7-182. This contrasts to the 3 per cent material OEF adjustment that we have applied to Ergon Energy for extreme weather events in the preliminary decision, which we have not departed from in this final decision.

<sup>46</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Australian Energy Regulator, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, pp. 13–14; see also Independent Review Panel on Network Costs, *Electricity Network Costs Review, Final Report*, 14 December 2012.

<sup>47</sup> AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 22.

This is set out in Table A.1 and figure A.1.

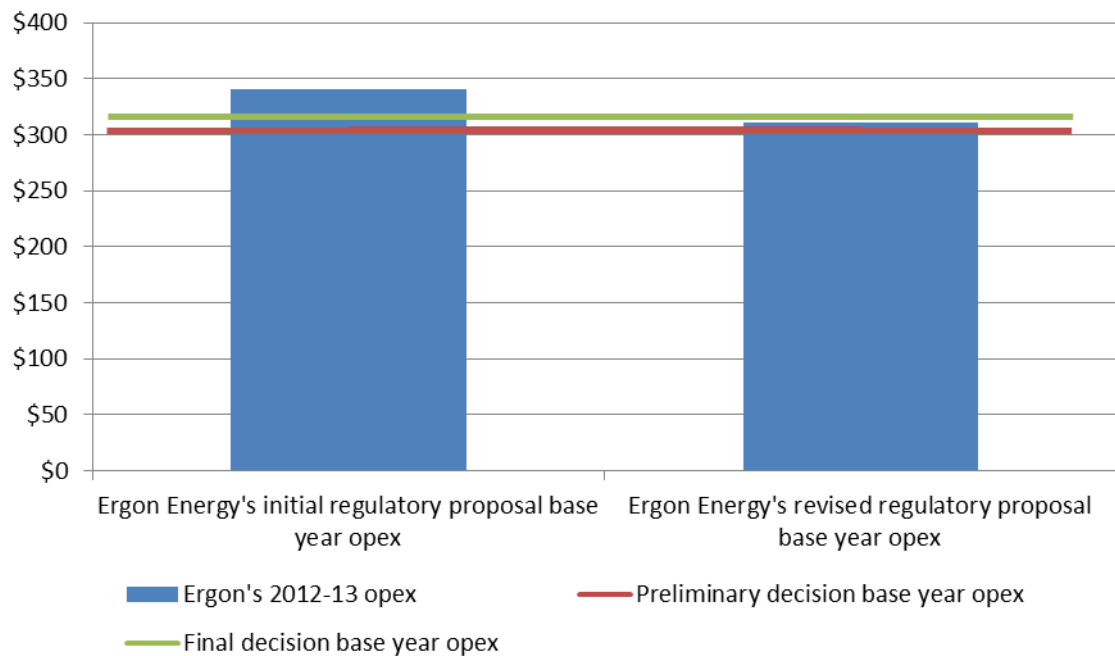
**Table A.1 Final decision Ergon Energy's base year opex (\$2014–15)**

	2012–13 Base Year	2013–14 Base Year
Revealed base opex (adjusted) <sup>a</sup>	\$315.9 million	\$319 million
<b>AER base opex</b>	<b>\$320 million</b>	<b>\$327.9 million</b>
Difference	\$4.1 million	\$8.9 million
Percentage difference	1.3%	2.8%

Note: (a) See section A.3 below.

Source: AER analysis.

**Figure A.1 Ergon Energy's base year opex**



Source: AER analysis.

Table A.2 summarises the OEF adjustments and the immaterial OEF adjustments that we have applied in this final decision.

**Table A.2 Summary of OEF adjustments**

OEF adjustment	SD	PD	Reasons against our OEF adjustment criteria	
<b>OEF adjustments changed between the final decision and the preliminary decision</b>				
Cyclones	5.4%	4.6%	Exogeneity	This is beyond Ergon Energy's control.
			Materiality	Information provided by Ergon Energy suggests that the effect of cyclones on opex can be material.
			Duplication	The CD SFA model does not account for the effect of cyclones.
OH&S regulations	1.2%	0.5%	Exogeneity	This is beyond Ergon Energy's control.
			Materiality	Differences in OH&S regulations between jurisdictions materially affect service provider's opex.
			Duplication	The CD SFA model does not account for the effect of differences in OH&S regulations.

Source: AER analysis.

## A.2 Revised regulatory proposal and submissions

In its revised regulatory proposal, Ergon Energy did not accept our preliminary position on base year opex.<sup>48</sup>

Instead, Ergon Energy proposed 2013–14 as its base year and base year opex of \$312.7 million (\$2014–15).<sup>49</sup> Ergon Energy’s proposal also removes \$30.5 million (\$2014–15) of metering opex associated with its role as a metering data provider for types 5 and 6 metering installation. This metering opex was previously incorrectly included in Ergon Energy’s base year opex on the basis that it was classified as a standard control service. The default metering service is properly classified as an alternative control service.<sup>50</sup>

We received submissions on our preliminary decision base year opex position from Ergon Energy and other stakeholders.<sup>51</sup> Ergon Energy’s response included reports from Huegin Consulting (Huegin), Synergies Economic Consulting (Synergies), Frontier Economics (Frontier) and PricewaterhouseCoopers (PwC).<sup>52</sup> The submissions raised some new issues while rearguing other issues that we had previously addressed. Broadly, all of these issues relate to one of the following:

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<sup>48</sup> See generally, Ergon Energy, *Regulatory Proposal 2015-20 (Revised), Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015; Ergon Energy, *Sub 10.01: Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015.

<sup>49</sup> Ergon Energy, *06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs*, July 2015, p. 8.

<sup>50</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised), Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015, pp. 78 and 88.

<sup>51</sup> Alliance of Electricity Consumers, *Submission to the Australian Energy Regulator’s Preliminary Decision (Queensland), Energex 2015-16 to 2019-20 and Ergon Energy 2015-16 to 2019-20*, 3 July 2015, pp. 20–24; Bruce Mountain, *Queensland Draft Decision Conference*, 12 May 2015, pp. 15–24; Chamber of Commerce and Industry Queensland, *Submission to the Australian Energy Regulator on the Preliminary Determinations for Ergon Energy and Energex Revenue Determination*, 3 July 2015, pp. 6 and 7; Cotton Australia, *Re: AER Determination Ergon*, 3 July 2015, p. 2; Energy Retailers Association of Australia, *RE: Preliminary Decisions for Ergon Energy and Energex determinations 2015-16 to 2019-20*, 3 July 2015, p. 1; Hugh Grant, *Consumer Challenge Panel Perspectives, AER Preliminary Determination, Energex and Ergon Energy*, 12 May 2015, pp. 74–89; Hugh Grant, *Consumer Challenge Panel (CCP2 Panel) Submission: AER Preliminary 2015–20 Revenue Determinations: Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 4–5; Origin Energy, *Re: Submission to AER Preliminary Decision Queensland Electricity Distributors*, 3 July 2015, pp. 8 and 9; Queensland Council of Social Service, *Response to AER Preliminary Decision for Qld distributors*, 3 July 2015, pp. 18–19; Queensland Resources Council, *QRC letter of support for the submission from The Alliance of Electricity Consumers*, 3 July 2015; Queensland Resources Council, *Preliminary Decision – Ergon Energy Determination 2015-2020*, 3 July 2015, pp. 2 and 3; Total Environment Centre, *Submission to the AER on the Preliminary Decisions on the QLD DBs’ Regulatory Proposals 2015-20*, July 2015, p. 8.

<sup>52</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination*, 1 July 2015; Huegin Consulting, *AER Operating Environment Factors: Huegin review of the bushfire factor*, 21 July 2015; PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015; PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015; PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015; PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015; Jacobs, *AER Preliminary Decision Response: Ergon Energy Reliability Impact Assessment*, 12 June 2015; Synergies Economic Consulting, *Further analysis of Ergon’s efficiency in the light of customer consultations*, July 2015; Frontier Economics, *Peer review of Huegin report*, 23 July 2015.

- the assessment approach we applied in the preliminary decision
- our application of and the data we used in the CD SFA model
- our application of the OEF adjustments
- the conclusions reached by DAE in their detailed review
- not providing a transition allowance.

In relation to the OEF adjustments we applied in the preliminary decision, the submissions questioned the approach we used to assess and apply OEF adjustments.<sup>53</sup> Further, Ergon Energy and its consultants, Huegin and PwC, specifically raised:

- concerns with the OEF adjustments we applied for bushfire risk, capitalisation practices, customer density, economies of scale and scope, extreme weather events, OH&S regulations, reliability outcomes, safety outcomes, solar uptake and subtransmission assets<sup>54</sup>
- new OEF adjustments for economies of scope and property portfolios.<sup>55</sup>

We did not receive any submissions on other OEF adjustments we applied in the preliminary decision.<sup>56</sup>

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<sup>53</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination – Addendum 2*, 1 July 2015, pp. 18 and 19; PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, p. 3; PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, p. 4; Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, p. 15; Hugh Grant, *Consumer Challenge Panel (CCP2 Panel) Submission: AER Preliminary 2015–20 Revenue Determinations: Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 49–52.

<sup>54</sup> Ergon Energy, *Submission on the Queensland Revised Regulatory Proposals*, 24 July 2015, pp. 10–27; Ergon Energy, *Revised Proposal: Attachment 0A.01.02, July 2015*, p. 4; PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, pp. 8–10 and 15–16; PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015; PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015, p. 11; Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination – Addendum 2*, 1 July 2015, pp. 19 and 43–45; Huegin Consulting, *AER Operating Environment Factors: Huegin review of the bushfire factor*, 21 July 2015; Jacobs, *AER Preliminary Decision Response: Ergon Energy Reliability Impact Assessment*, 12 June 2015; Synergies, *Further analysis of Ergon's efficiency in the light of customer consultations*, July 2015, p. 4; PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015, p. 11.

<sup>55</sup> PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, pp. 8–10; Ergon Energy, *Revised Proposal: Attachment 06.01.05*, p. 74.

<sup>56</sup> The OEF adjustments include: activity scheduling, advanced metering infrastructure, asset age, asset volumes, building regulations, capital contributions, communication networks, competition from mining, contaminated land management, contestable services, corrosive environments, critical national infrastructure, cultural heritage, environmental regulations, environmental variability, fire ants, grounding conditions, licence conditions, line length, line sag, load factor, load growth, mix of demand to non-demand customers, network accessibility, network control centres, outsourcing, past ownership, planning regulations, population growth, private power poles, proportion of 11kV and 22kV, proportion of wood poles, rainfall and humidity, rising and lateral mains, risk appetite, service classification, shape factors, skills required by different distributors, SWER, taxes and levies, temperature, termite

## A.3 Reasons

As we did in the preliminary decision, we have adjusted Ergon Energy’s reported 2013–14 revealed expenditure to remove certain costs because the base year opex of other service providers do not include these costs.<sup>57</sup> These adjustments result in an adjusted base year opex of \$319 million (\$2014–15).

Ergon Energy applied adjustments to its reported 2013–14 opex for its cost allocation method (CAM) and for ‘accounting adjustments’.<sup>58</sup> We did not accept these adjustments because Ergon Energy did not:

- substantiate why increasing the audited amount of opex in its regulatory accounts was appropriate
- make corresponding adjustments to its reported actual opex for 2012–14 for the EBSS (which would have reduced its EBSS carryover).

The adjustments we made are set out in table A.3.

**Table A.3 AER forecast of base opex (million, \$2014–15)**

	Final decision
Reported 2013–14 opex (from regulatory accounts)	486.6
Remove debt raising costs	–4.5
Remove movement in provisions	2.8
Remove feed-in tariff payments	–123.7
Service classification adjustment	–42.3
Adjusted base opex	319

Source: AER analysis.

In arriving at our final decision we have:

- applied the same assessment approach that we applied in the preliminary decision
- used 2013/14 as the base year

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exposure, topography, traffic management, transformer capacity owned by customers, transmission connection point charges, undergrounding, unregulated services and works conditions.

<sup>57</sup> We removed debt raising costs, movement in provisions, feed-in tariff payments and expenditures not associated with standard control services in the 2015–20 regulatory control period for the following reasons. Debt raising costs are separately accounted for by a benchmark debt raising cost allowance. Movement in provisions do not represent the actual cost incurred in delivering network services (we discuss this further in attachment 9). Ergon Energy recovers feed-in tariff payments through a separate jurisdictional scheme. Only expenditures associated with standard control services in the 2015–20 regulatory control period can form part of a total opex forecast: NER, cl. 6.5.6(b)(2).

<sup>58</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised)*, July 2015, p. 91.

- sought further advice from our consultants, Economic Insights and DAE in response to some of the issues raised in the Huegin, Synergies, Frontier Economics and PwC reports<sup>59</sup>
- adjusted Ergon Energy's efficiency score.

We have adjusted Ergon Energy's efficiency score by:

- removing \$30.5 million (\$2014–15) of metering opex
- using non-coincident maximum demand data for Australia, New Zealand and Ontario
- increasing the OEF adjustments by 1.8 per cent from 24.4 to 26.2 per cent for cyclones and OH&S obligations.

We discuss our reasons for our final position in the remainder of this appendix. Specifically, we discuss in:

- section A.4, our assessment approach
- section A.5, our application of the Cobb Douglas Stochastic Frontier Analysis (CD SFA) model
- section A.6, our application of the OEF adjustments.

Although Ergon Energy has proposed 2013/14 as its base year, our assessment in this final decision is based on using 2012/13 as its base year. So are the conclusions reached by DAE that we have relied on. However, regardless of whether 2012/13 or 2013/14 is used as Ergon Energy's base year, we have arrived at the same final position to accept Ergon Energy's revealed expenditure. In either case, we did not find any material inefficiency. Using 2012/13 as the base year results in our estimate of the efficient base year opex differing from that of Ergon Energy's proposed base year opex by 1.3 per cent. Using 2013/14 as the base year results in our estimate of base year opex being 2.8 per cent higher than Ergon Energy's revealed expenditure.

Finally, Ergon Energy submitted that we should change our assessment approach given that it is being challenged before the Australian Competition Tribunal (Tribunal) and the Federal Court in the context of the New South Wales and Australian Capital Territory distribution determinations. We do not agree. In the absence of any contrary findings in these merits and judicial review processes, we consider that our approach remains appropriate.

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<sup>59</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015; Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Draft Addendum to our April Report – Ergon Energy's Revised Proposal*, 13 October 2015.



## A.4 Our assessment approach for base year opex

The approach that we apply to assessing base year opex in this final decision is the same approach that we applied in the preliminary decision. In reviewing some of the submissions we received it appears that there may be some misunderstanding of our approach. For example, Ergon Energy submitted that we:

- applied our benchmarking techniques in a ‘deterministic’ manner
- did not use its proposal as the ‘starting point’ for our assessment
- did not take into account its realistic circumstances
- did not properly take into account the opex factors, the revenue and pricing principles (RPPs) and the national electricity objective (NEO).<sup>60</sup>

We do not agree with these submissions, and provide the following reasons.

In section 7.3, we discussed the two tasks that the NER requires us to undertake in respect of a service provider’s total forecast opex.<sup>61</sup> The first task requires us to form a view about whether we are satisfied Ergon Energy’s proposed total forecast opex reasonably reflects the opex criteria. The second task requires us to determine a substitute estimate, should we form the view in the first task that we are not satisfied that Ergon Energy’s proposed total forecast opex reasonably reflects the opex criteria.

In the first task we assess whether Ergon Energy’s proposed base year opex is an appropriate starting point for a total forecast opex that we would be satisfied reasonably reflects the opex criteria. We do so by identifying whether Ergon Energy’s proposed base year opex is materially inefficient. This involves testing Ergon Energy’s proposed base year opex against the results of the following qualitative and quantitative assessment techniques:

- partial performance indicators (PPIs)
- index based multi-factor productivity measures (MPFP and multilateral total factor productivity (MTFP))
- econometric modelling techniques (CD SFA, CD least squares estimate regression (LSE) and translog LSE)
- cost category analysis
- detailed reviews of key expenditure categories.<sup>62</sup>

This is the same analysis that we apply in determining the level of base year opex in our alternative estimate. As we discussed in section 7.3, we use our alternative

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<sup>60</sup> See, e.g., Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, pp. 5, 12, 20, 23 and 27–35.

<sup>61</sup> NER, cll. 6.5.6(c), 6.5.6(d) and 6.12.1(4).

<sup>62</sup> AER, *Preliminary Decision Ergon Energy determination 2015-16 to 2019-20: Attachment 7 – Operating expenditure*, April 2015, pp. 7-46–7-53.

estimate to assess Ergon Energy's proposal at the total opex level, and generally as our substitute estimate in the second task.

Importantly, we did not apply any one of these techniques deterministically. Nor did we not begin with Ergon Energy's proposal.<sup>63</sup> We apply each of the quantitative techniques independently. The results of each of these quantitative techniques are relevant to determining whether it is necessary for us to undertake further analysis such as qualitative cost category analysis and detailed reviews. In particular, each result reveals the extent to which each opex criterion is reflected in a forecast, often in multiple ways. Efficiency benchmarking, for instance, directly compares the efficient costs of comparable firms that provide similar services. As this compares the actual costs of real businesses that provide substantively the same services, these results incorporate a realistic expectation of the cost inputs an objectively prudent operator requires to provide its services, given a realistic expectation of demand forecasts and costs inputs. Each result independently informs us about whether Ergon Energy's proposed base year opex is an appropriate starting point for a total forecast opex that we would be satisfied reasonably reflects the opex criteria.

Of these techniques, the results of the CD SFA model together with the OEF adjustments that we applied are the best method to identify any material inefficiency. We extensively explain our reasons in the preliminary decision.<sup>64</sup> The reasons included our finding that the CD SFA model is statistically superior to other benchmarking methods are that:

- it specifies the relationship between opex and outputs and some operating environment factors in an opex cost function (unlike DEA and MPFP)
- it directly estimates an efficient frontier (unlike the other econometric models and MPFP)
- it contains a random error term that separates the effect of data noises or random errors from inefficiency (unlike econometric models, DEA and MPFP)
- the results of the Cobb Douglas SFA model can be verified with statistical testing (unlike DEA and MPFP).

Statistical testing of the CD SFA model showed:

- all the parameters were of the expected sign
- the parameter estimates all have plausible values

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<sup>63</sup> c.f. Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, pp. 5 and 26.

<sup>64</sup> AER, *Preliminary Decision Ergon Energy determination 2015-16 to 2019-20: Attachment 7 – Operating expenditure*, April 2015, pp. 7-53–7-67. As to our approach to applying OEF adjustments, see AER, *Preliminary Decision Ergon Energy determination 2015-16 to 2019-20: Attachment 7 – Operating expenditure*, April 2015, pp. 7-169–174.

- estimated coefficients are statistically significant which indicates that they have been estimated to a high degree of precision
- the confidence intervals for the efficiency scores are relatively narrow
- its results are consistent with the results of other sophisticated econometric opex models (CD LSE and translog LSE) and the opex MPFP model, which applies a different model specification and does not rely on any international data.

In terms of the CD SFA model, the highest efficient score possible is 1. The lowest efficiency score possible is 0. We determined that a score of 0.77 is the appropriate point against which to compare Ergon Energy's proposed base year opex. This score represents the lowest efficiency score of all Australian distributors that achieved scores in the top quartile of performance. More than a third of the service providers in the NEM operate in varied rural and urban environments, were able to perform as efficiently as, or more efficiently than this benchmark comparison point. A distributor that scores below this point (as Ergon Energy did in the preliminary decision and in this final decision) has incurred a level of expenditure that is unlikely to form the starting point of a forecast that we would be satisfied reasonably reflects the opex criteria. However, we consider how far the service provider is from the comparison point in reaching our conclusion on whether the inefficiency we find is material. This recognises that while there is scope for Ergon Energy to address inefficiencies over the regulatory control period, they are not sufficiently material for us to depart from Ergon Energy's revealed expenditure.

This approach achieves an appropriate balance between the following considerations:

- making an adjustment that sufficiently removes any material inefficiency from the revealed expenditure
- incorporating a margin for potential forecasting, modelling and data errors
- avoiding the risk of undercompensating a service provider
- providing a service provider with a reasonable opportunity to recover at least the efficient costs of providing services
- exercising caution, given this is the first application of benchmarking opex in this manner for Ergon Energy.<sup>65</sup>

In the preliminary decision, each of the results of the techniques that we applied pointed us to the conclusion that Ergon Energy's base year opex was materially inefficient. A total forecast opex predicated on that base year opex would exceed that required to meet the realistic expectation of demand forecasts and cost inputs.<sup>66</sup> It was therefore not an appropriate starting point to determine a total forecast opex allowance that we would be satisfied reasonably reflects the opex criteria. However, as we

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<sup>65</sup> In balancing these considerations, we have taken into account the RPPs.

<sup>66</sup> AER, *Preliminary Decision Ergon Energy determination 2015-16 to 2019-20: Attachment 7 – Operating expenditure*, April 2015, p. 45.

discuss in this appendix, the results of these techniques has now led us to conclude that Ergon Energy's revealed costs can be used as base year opex.

## A.4.1 Transition path allowance

In its revised regulatory proposal Ergon Energy did not accept our position in the preliminary decision that did not provide a ‘transition path allowance’ to a lower opex.<sup>67</sup> Ergon Energy submitted that should we make a ‘distribution determination that provided for significant cuts to existing levels of expenditure’, we should provide it with a transition path allowance.<sup>68</sup> This submission is based on the following propositions:

- a transition path allowance is consistent with an allowance that reasonably reflects the opex criterion that refers to a realistic expectation of Ergon Energy’s demand forecasts and cost inputs
- the costs associated with entering into, varying and exiting specific arrangements are costs that are not necessarily inefficient or imprudent, the corollary of which is that a prudent and efficient service provider may properly incur them
- to not provide a transition path allowance is counter to the operation of the incentives created under chapter 6 of the NER
- the AER has the power (if not a duty) to incorporate such a transition path.<sup>69</sup>

We do not agree, and provide the following reasons.

First, an allowance that exceeds the amount that we are satisfied reasonably reflects the opex criteria is not the amount that we would be satisfied reasonably reflects the opex criteria. This excess is not efficient and providing such an allowance is at odds with the revenue and pricing principle that requires us to have regard to providing Ergon Energy with a reasonable opportunity to recover at least its efficient costs.<sup>70</sup> In our view, whether we have the power or duty to incorporate a transition path allowance that exceeds what we are satisfied of is a question that does not arise.<sup>71</sup>

Second, the argument that the opex criterion at clause 6.5.6(c)(3) supports the provision of a transition allowance requires us to take a subjective view of the individual circumstances that Ergon Energy faces or the specific arrangements it may have entered into. As we discussed in section 7.3, we consider each opex criterion objectively. ‘Realistic cost inputs’ are not synonymous with Ergon Energy’s actual costs. If that were the meaning of the criterion, we would be required to determine a forecast that compensates Ergon Energy for its actual costs. This is not the case. The criterion requires us to consider realistic cost inputs in the context of the exogenous

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<sup>67</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised)*, Appendix E: The need for a ‘transition path’ for operating and capital expenditure, July 2015, p. 162.

<sup>68</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised)*, Appendix E: The need for a ‘transition path’ for operating and capital expenditure, July 2015, p. 162.

<sup>69</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised)*, Appendix E: The need for a ‘transition path’ for operating and capital expenditure, July 2015, pp 163–166; PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015, pp. 4 and 8–15.

<sup>70</sup> NEL, s. 7A(2).

<sup>71</sup> Ergon Energy, *Regulatory Proposal 2015–20 (revised)*, Appendix E: The need for a ‘transition path’ for operating and capital expenditure, July 2015, pp. 163–165.

circumstances that Ergon Energy faces. Exogenous circumstances are those beyond Ergon Energy's control, such as those circumstances arising from its location, network characteristics and from the demand for services that Ergon Energy supplies. It is appropriate for Ergon Energy to be compensated for the efficient, prudent and realistic costs that it incurs because of these exogenous circumstances.

Importantly, these are not the costs that Ergon Energy incurs because of the discretionary decisions or arrangements that it may have voluntarily entered into. This includes the extent to which we may find that Ergon Energy has a degree of discretion in negotiating or entering into the specific terms of contractual arrangements associated with the obligations that are exogenously imposed on it. This is regardless of whether the contractual arrangements are long-term, short-term or the renegotiation of existing contractual arrangements. These are all discretionary decisions for Ergon Energy to make in full consideration of the regulatory framework and the other regulatory or licence obligations that it faces.

Compensating for such costs is at odds with the incentives in chapter 6 of the NER that apply to Ergon Energy. Ergon Energy is provided with a target allowance that is efficient, prudent and realistic. This creates incentives that encourage Ergon Energy to incur costs efficiently. In turn, this minimises the costs and risks of potentially under and over investing in and using the network and promotes efficient investment in the long-term interest of consumers.<sup>72</sup> In particular, the long-term interests of consumers are served by ensuring that Ergon Energy is not compensated for the costs that it should bear. To do otherwise deprives Ergon Energy of the opportunity to respond to the incentives that apply to it. Despite PwC's submission to the contrary, this results in a proper allocation of risk between Ergon Energy and consumers.<sup>73</sup>

We also do not agree that our approach was inappropriately retrospective or that we arrived at our conclusions with the benefit of hindsight.<sup>74</sup> The reasons of the Tribunal in *Appeal by SPI Electricity Pty Ltd* [2012] ACompT 11 as submitted by PwC do not support this.<sup>75</sup> In many ways, assessing forecast opex (including assessing a transition

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<sup>72</sup> NEL, ss. 7A(6) and 7A(7).

<sup>73</sup> PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015, pp. 4 and 14.

<sup>74</sup> PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015, p. 9.

<sup>75</sup> PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015, p. 9. The Tribunal's comments were made in the context of the expenditure tests in the Victorian Advanced Metering Infrastructure (AMI) Order in Council. They are not relevant to considering a transition path allowance under the NER for the following reasons. First, the Tribunal's reasons concerning costs associated with foreign exchange contracts reflected agreed submissions from SP AusNet and us at the time that the costs in question were let in accordance with a competitive tender process, and thereby deemed prudent under the terms of the expenditure tests prescribed in the AMI Order in Council. Those reasons do not refer to any retrospective review undertaken by the AER in the context of foreign exchange contracts: *Appeal by SPI Electricity Pty Ltd* [2012] ACompT 11, [40]–[44]. Second, even if PwC meant to refer to the Tribunal's observations that we did not take into account the costs already spent by SP AusNet in rolling out WiMAX instead of mesh radio (at *Appeal by SPI Electricity Pty Ltd* [2012] ACompT 11, [119]–[139]), this is not relevant. Our decision that was the subject of review in the case was made under the Victorian AMI Order in Council. The regulatory regime set out in the AMI Order, which at that time was similar in effect to a cost pass-through regime, is starkly different to that in Chapter 6 of the NER. Further, the expenditure tests the subject of review in that case are peculiar to the AMI Order in Council. The same considerations

path allowance) is necessarily a retrospective task given the nature of the information before us. Indeed, the actual or expected expenditure in preceding regulatory control periods is one of the opex factors that we are required to take into account.<sup>76</sup> We note that the Tribunal has previously stated:<sup>77</sup>

Prudence is often best judged by the absence of evidence suggesting a lack of it. In the case of electricity networks, imprudence might be most discernible if there was evidence of failure to invest adequately, accompanied by identified adverse consequences, and is thus best assessed retrospectively.

Third, these propositions do not recognise that the techniques we applied to assess Ergon Energy's proposed total forecast opex, and in particular, its proposed base year opex, directly account for a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives. For example, the data we have used in the CD SFA is that of real service providers in the NEM and from abroad. To the extent there are exogenous differences between service providers, or unforeseen circumstances, this is addressed through the OEF adjustments we have applied and the cost pass through mechanisms provided for in chapter 6 of the NER. Neither Ergon Energy nor PwC have established that techniques we have applied do not already account for the realistic expectation of demand forecasts and cost inputs.

Fourth, neither we, nor any of the stakeholders in their submissions, identified a situation where compensating Ergon Energy for endogenous circumstances would not undermine the operation of the incentives created by chapter 6 of the NER.

Finally, we do not agree with PwC's submission that we should consider Ergon Energy, as a provider of a natural monopoly service, in contrast to a competitive business that can make expenditure decisions without constraint particularly in light of the licence conditions it must comply with.<sup>78</sup> Many competitive businesses make expenditure decisions in light of having to comply with licence conditions or other obligations as well.

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discussed above in respect of the appropriateness of a transition path allowance do not arise under the AMI Order in Council.

<sup>76</sup> NER, cl. 6.5.6(e)(5).

<sup>77</sup> *Application by EnergyAustralia and Others* [2009] ACompT 8 at [141]-[142].

<sup>78</sup> PricewaterhouseCoopers, *Ergon Energy Transition Allowance*, 1 July 2015, p. 11.

## A.5 Benchmarking

### A.5.1 Application of the CD SFA model

Ergon Energy, Huegin, Frontier Economics and Synergies raised a number of issues regarding our approach to benchmarking and the use of the CD SFA model in the preliminary decision. In summary, they claim that:

- our benchmarking analysis is inherently sensitive and that the results of the CD SFA model vary widely
- we should not use data for the 2006–08 period because it unduly influences the results and that we should instead use forecast data in the benchmarking analysis
- our benchmarking does not consider Ergon Energy's large service area or its 'different attributes'
- we should consider using data envelopment analysis (DEA)
- the changes CitiPower and Powercor have proposed to their capitalisation practices that will take effect next year may affect our efficiency score for Ergon Energy.<sup>79</sup>

Other stakeholders submitted that we should not have adjusted Ergon Energy's base year opex to that of AusNet Services. Some submitted that we should have adjusted Ergon Energy's base year opex to that of the efficient frontier business, CitiPower.<sup>80</sup> Others submitted that the gap between our benchmark comparison point and CitiPower was not justified or that it warranted further reductions in Ergon Energy's forecast opex.<sup>81</sup>

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<sup>79</sup> See generally, Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015; Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination*, 1 July 2015; Synergies Economic Consulting, *Further analysis of Ergon's efficiency in the light of customer consultations*, July 2015.

<sup>80</sup> Hugh Grant, *Consumer Challenge Panel Perspectives, AER Preliminary Determination, Energex and Ergon Energy*, 12 May 2015, pp. 74–89; Hugh Grant, *Consumer Challenge Panel (CCP2 Panel) Submission: AER Preliminary 2015–20 Revenue Determinations: Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 4 and 5.

<sup>81</sup> Alliance of Electricity Consumers, *Submission to Energex and Ergon Energy's Revised Regulatory Proposals (Queensland): AER Regulatory Determination 2015–2020*, 24 July 2015, p. 10; Alliance of Electricity Consumers, *Submission to the Australian Energy Regulator's Preliminary Decision (Queensland), Energex 2015-16 to 2019-20 and Ergon Energy 2015-16 to 2019-20*, 3 July 2015, pp. 20–24; Bruce Mountain, *Queensland Draft Decision Conference*, 12 May 2015, pp. 15–24; Cotton Australia, *Re: AER Determination Ergon*, 3 July 2015, p. 2; Energy Retailers Association of Australia, *RE: Preliminary Decisions for Ergon Energy and Energex determinations 2015-16 to 2019-20*, 3 July 2015, p. 1; Origin Energy, *Re: Submission to AER Preliminary Decision Queensland Electricity Distributors*, 3 July 2015, pp. 8 and 9; Queensland Council of Social Service, *Response to AER Preliminary Decision for Qld distributors*, 3 July 2015, pp. 18 and 19; Queensland Resources Council, *QRC letter of support for the submission from The Alliance of Electricity Consumers*, 3 July 2015; Queensland Resources Council, *Preliminary Decision – Ergon Energy Determination 2015-2020*, 3 July 2015, pp. 2 and 3; Total Environment Centre, *Submission to the AER on the Preliminary Decisions on the QLD DBs' Regulatory Proposals 2015-20*, July 2015, p. 8.



We engaged Economic Insights to review the Huegin and Synergies reports.<sup>82</sup> Having considered the submissions on our benchmarking approach, and the findings of Economic Insights' review, for the following reasons we have decided not to depart from the way in which we applied benchmarking and the CD SFA model in the preliminary decision.

First, our benchmarking analysis and the results of the CD SFA model are not inherently sensitive. All models are sensitive to changes in assumptions or inputs. That in itself does not determine whether the results of a model are unreliable. One test to determine whether a model is inherently sensitive is to compare its results to that of similar models. In this case, the results of the CD SFA model are consistent with the results of different benchmarking models, econometric estimation techniques, functional forms, output specifications and datasets.<sup>83</sup> This indicates that the results of the CD SFA model are inherently stable and not inherently sensitive. We also note that Economic Insights has not been able to replicate the wide variation in efficiency scores that Huegin presents.<sup>84</sup>

Second, we do not agree with the assertion that we should not use data for the 2006–08 period or that we should use forecast data in our benchmarking analysis. Huegin submitted that we should exclude this data because of the lower expenditure of the frontier businesses prior to 2009.<sup>85</sup> Whilst we recognise that the Victorian distributors have increased their expenditure since 2011 following the findings of the Victorian Bushfire Royal Commission, their expenditure prior to that reflects a level of regulation regarding bushfires that is more likely to be comparable with distributors in other jurisdictions. We are not convinced that this data inflates the efficiency target as Huegin claims. In any case, using more years of data than less has significant advantages in terms of smoothing out the influence of unusual events.<sup>86</sup> As to the use of forecast data, this is at odds with using the revealed expenditure in Ergon Energy's base year as part of the base/step/trend approach. The point of using the revealed expenditure in a base year is that it was previously subject to the incentives under the regulatory framework, and reflects the actual expenditure incurred by the distributor in providing services to consumers. This is not the case with forecast data.

Third, we are satisfied that the CD SFA model accounts for Ergon Energy's large service area. It does so because the CD SFA accounts for line length. This customer density measure is the main influence on Ergon Energy's opex. Other measures, such

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<sup>82</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015.

<sup>83</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, p. 2.

<sup>84</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, pp. 10–15.

<sup>85</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination*, 1 July 2015, pp. 38 and 40. See also Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, pp. 18 and 19.

<sup>86</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, p. 3.

as customer numbers per square kilometre, are unlikely to be robust enough for us to use in our benchmarking analysis.<sup>87</sup>

Fourth, the DEA model developed by Synergies suffers a number of shortcomings. Principally, it relies on a reliability variable that arbitrarily produces different results depending on the value assigned to that variable. It also assumes that output and input prices are all equal to one and that Ergon Energy experiences decreasing returns to scale.<sup>88</sup> Synergies did not provide any justification for why these assumptions may be realistic.

Fifth, we have considered in detail the submissions that raised issue with our choice of the benchmark comparison point that we used to develop our alternative estimate.<sup>89</sup> The Consumer Challenge Panel (CCP) submitted that we should have chosen a benchmark comparison point equal to that of the efficient frontier business, CitiPower. The Energy Users Association of Australia submitted that the lowest performing service provider in the top quartile was United Energy Distribution at 0.84 and not AusNet Services at 0.77, suggesting that the comparison point is too low.

Our choice of a benchmark comparison point of 0.77 reflects the advice that we received from Economic Insights following our draft decisions for the New South Wales and Australian Capital Territory distribution determinations.<sup>90</sup> Economic Insights noted that Ofgem in the United Kingdom has applied different approaches in benchmarking electricity and gas networks to account for possible data quality issues. Having regard to these different approaches, Economic Insights concluded that it was appropriate to adopt a comparison point of the distributor at the bottom of the top third of actual efficiency scores (0.77), rather than the bottom of the top quartile of actual efficiency scores (0.84). Further, a benchmark comparison point of 0.77 rather than 0.84 achieves an appropriate balance between the considerations that we identified in section A.4 above. Adopting a benchmark comparison point of the distributor at the efficient frontier, CitiPower, does not achieve this balance.

We have therefore decided to maintain our choice of 0.77 as the benchmark comparison point in this final decision.

Finally, we recognise that the changes proposed by CitiPower and Powercor to their CAMs may affect Ergon Energy's efficiency score that results from the CD SFA model. However, sensitivity analysis taking into account CitiPower's proposed changes

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<sup>87</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, p. 16.

<sup>88</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, pp. 22–24.

<sup>89</sup> Hugh Grant, *Consumer Challenge Panel (CCP2 Panel) Submission AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 47 and 48; Energy Users Association of Australia, *Submission to the AER: Draft Determination for Energex & Energex Revised Proposal, Energex 2015–2020 Regulatory Control Period*, 24 July 2015, p. 10.

<sup>90</sup> Economic Insights, *Responses to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, April 2015, pp. 65 and 66.

undertaken by Economic Insights demonstrates that the proposed changes have a minimal impact on Ergon Energy's efficiency score and do not affect the rankings.<sup>91</sup>

## A.5.2 Choice of base year

In its revised regulatory proposal, Ergon Energy proposed to use 2013/14 as its base year on the basis that the 2013/14 financial year represents the most recent audited financial statements available at the time it submitted its revised regulatory proposal.<sup>92</sup> This departs from Ergon Energy's previous proposal in its initial regulatory proposal to use 2012/13 as its base year, which we accepted in our preliminary decision.<sup>93</sup>

Nevertheless, we have decided to use Ergon Energy's proposal to use the 2013/14 base year in its revised regulatory proposal 2013/14 as Ergon Energy's base year. We find that using the more recent data does not change the outcome of our analysis.

## A.5.3 Metering opex

Ergon Energy submitted that \$28.8 million (\$2012–13) of metering opex associated with its role as a metering data provider for types 5 and 6 metering installation was incorrectly included in its standard control service base year opex. This was based metering services being classified as an alternative control service and not as a standard control service in the 2015–20 regulatory control period.<sup>94</sup>

We agree. The removal of this metering opex from Ergon Energy's revealed expenditures is uncontroversial. However, this has affected our decision to use Ergon Energy's revealed costs in our forecasts opex.

## A.5.4 Demand data

In the preliminary decision we used coincident maximum demand data for Australia and New Zealand and non-coincident maximum demand data for Ontario to derive the ratcheted maximum demand output used in the CD SFA model.

Since the preliminary decision, we have identified that we did not use non-coincident maximum demand data for Australia, New Zealand and Ontario consistently for the purposes of deriving the ratcheted maximum demand output. We have therefore used

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<sup>91</sup> This analysis did not take into account Powercor's proposed changes on the basis that Powercor already expenses an above average proportion of its total expenditure in excess of that of Ergon Energy: see Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, pp. 8 and 9.

<sup>92</sup> Ergon Energy, *06.01.01 - (Revised) Forecast Expenditure Summary - Operating Costs*, July 2015, p. 8; Ergon Energy, *Regulatory Proposal 2015-20 (Revised), Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015, pp. 78, 85, 88 and 89.

<sup>93</sup> AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 – Operating expenditure*, April 2015, pp. 7–45.

<sup>94</sup> Ergon Energy, *Regulatory Proposal 2015-20 (Revised), Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015, p. 78.

non-coincident maximum demand data consistently in this final decision. Coincident and non-coincident demand data across the Australian and New Zealand distributors are highly correlated. Using non-coincident demand data consistently has a minimal effect on the results of the CD SFA model.<sup>95</sup>

### A.5.5 Findings of the DAE report

Ergon Energy and PwC raised a number of issues about the findings DAE made in its report that we used to inform our preliminary decision.<sup>96</sup> In summary, they did not agree with the propositions put by DAE that Ergon Energy's labour practices and costs were inefficient in comparison to the comparator service providers. They also did not agree with DAE's view regarding the extent to which this was attributable to the conditions specified in their enterprise bargaining agreements (EBAs). Specifically, they raised issue with:

- DAE's approach and methodology
- whether the EBA conditions are matters within Ergon Energy's control
- the benefits of the Powercor Local Service Agent (LSA) model
- market-testing of SPARQ services.<sup>97</sup>

We engaged DAE to review these issues. The conclusions DAE have arrived at have not changed.<sup>98</sup> We found that the analysis and reasons underlying DAE's review are persuasive and supported by evidence. Accordingly, we have taken into account the conclusions DAE arrived at in its review.

First, the issues raised about DAE's approach and methodology rest on a claim that their starting point was biased. Biased because DAE did not challenge our benchmarking analysis and that they did not have sufficient evidence to support their conclusions. This is incorrect. We asked DAE to review the key factors that may be explain the gap in opex performance identified by our benchmarking analysis and the extent to which Ergon Energy had implemented the recommendations of the IRP. We did not ask DAE to comment on our benchmarking analysis. As to the issue of sufficient evidence, this is also incorrect. DAE reviewed a significant volume of evidence. DAE explains this extensively in their report.<sup>99</sup>

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<sup>95</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, p. 25.

<sup>96</sup> Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, pp. 8 and 9; PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015.

<sup>97</sup> Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, pp. 8 and 9; PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015.

<sup>98</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, pp. 3–6.

<sup>99</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, pp. 11 and 12.

Second, we did not ask DAE to review whether the EBA conditions are within Ergon Energy's control. DAE's task concerned the key factors that may be driving the gap in opex performance that our benchmarking analysis identified. DAE concluded that Ergon Energy's labour costs, attributable to the EBAs, goes some way to explaining this gap.<sup>100</sup> We note that DAE's review of Ergon Energy and PwC's submissions on this matter has not caused it to change its conclusions.<sup>101</sup>

Third, DAE has found that Ergon Energy has not yet fully investigated the potential efficiency benefits that it may realise by implementing an LSA model in regional depots as Powercor has done since the 1990s as recommended in the IRP.<sup>102</sup>

Finally, as to the market-testing of SPARQ services, we note that DAE remains of the view that limited ICT outsourcing has been undertaken by Ergon Energy in the base year.<sup>103</sup> This goes some way to explaining the inefficiency we have identified in the base year, notwithstanding our conclusion that it is not material.

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<sup>100</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, pp. 22–24.

<sup>101</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, p. 24.

<sup>102</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, p. 21.

<sup>103</sup> Deloitte Access Economics, *Queensland Distribution Network Service Providers Opex performance analysis, Addendum to our April Report – Ergon's Revised Proposal*, 13 October 2015, pp. 25–30.

## A.6 OEF adjustments

### A.6.1 Approach to applying OEF adjustments

Ergon Energy, Huegin and PwC raised a number of issues about our approach to assessing the OEF adjustments that we applied in the preliminary decision. In summary, they submitted:

- the dollar impacts of the OEF adjustments implied by our NSW final determinations are not plausible given the similarity between the networks of Endeavour Energy and Essential Energy
- correcting the small clerical errors that we made in the calculation of some of the OEF adjustments increases the benchmark forecast by \$4 million and indicates that the results are sensitive and unreliable
- we should apply the OEF adjustments before applying the CD SFA model, on the basis that the frontier is not appropriate
- we should undertake more analysis and consultation because the quantification of the OEF adjustments was based on limited information
- the large number of OEF adjustments we applied suggests that applying the CD SFA model is flawed
- we should make an additional OEF adjustment of 21.5 per cent.<sup>104</sup>

The CCP also raised a number of issues on the OEF adjustments that we applied. In summary, the CCP submitted that the OEF adjustments we applied were arbitrary and in excess of that required to account for potential modelling and data errors.<sup>105</sup>

These submissions did not cause us to depart from our position in the preliminary decision for the following reasons.

First, we do not agree that the networks of Endeavour Energy and Essential Energy are similar so that the impact of the OEF adjustments we applied in their distribution determinations in the context of Ergon Energy is not plausible. The networks of Endeavour Energy and Essential Energy differ. Endeavour Energy has more customers than Essential Energy and services a higher maximum demand. The CD SFA model accounts for this by measuring the impact of line length, customer numbers and demand. The result of the CD SFA model, after applying the OEF adjustments of \$26.7 million (\$2013–14) for Endeavour Energy and \$29.8 million (\$2013–14) for

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<sup>104</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination – Addendum 2*, 1 July 2015, pp. 18 and 19; Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year opex*, 3 July 2015, p. 15. PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, p. 3; PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, p. 4.

<sup>105</sup> Hugh Grant, *Consumer Challenge Panel (CCP2 Panel) Submission AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, pp. 49–52.

Essential Energy, is that Essential Energy requires 32 per cent more opex than Endeavour Energy. This is also consistent with Essential Energy's actual opex being 35 per cent higher than that of Endeavour Energy between 2006 and 2009.

Second, all forecasting methods are susceptible to clerical errors. This does not establish that a forecast methodology or its results are overly sensitive or unreliable. For example, we note that correcting the coding errors Ergon Energy identified in its original opex forecast has an impact of \$11.5 million (\$2013–14) over the 2015–20 regulatory control period.<sup>106</sup> That exceeds the \$4 million that follows from correcting the clerical errors we made.<sup>107</sup>

Third, making OEF adjustments before applying (or incorporating those adjustments directly into) the CD SFA model, absent a comprehensive and complete set of data, runs the risk of biased results. There is a point at which adding more explanatory variables in a model will lead to less reliable results. We note that Economic Insights is also of the view that applying OEF adjustments ex-post is more transparent and objective than doing so ex-ante.<sup>108</sup>

Fourth, we do not accept that the OEF adjustments that we applied to Ergon Energy in the preliminary decision (and in this final decision) were arbitrary or that they indicate the results of the CD SFA model are flawed. We have systematically investigated over 60 OEF adjustments, which has been the result of the extensive consultation we undertook on our benchmarking with service providers and other interested stakeholders.<sup>109</sup> In our view, our investigation of over 60 OEF adjustments ensures that our benchmarking is robust and properly tailored so that the base year opex properly reflects, among other things, the realistic expectations of cost inputs that a prudent operator would require to achieve the opex objectives. Whilst we recognise that the OEF adjustments we will apply in future processes will evolve over time, we do not accept that the OEF adjustments that we applied to Ergon Energy were or are arbitrary.

Fifth, the NEL and the NER require us to balance the interests of both Ergon Energy and consumers.<sup>110</sup> This includes providing Ergon Energy with a reasonable opportunity to recover at least its efficient costs.<sup>111</sup> In circumstances where this is the first application of benchmarking for Energex and that to some extent, all models are susceptible to errors, we maintain our view that the approach we have applied is

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<sup>106</sup> Ergon Energy, *06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs*, July 2015, p. 11.

<sup>107</sup> Ergon Energy, *Submission to the AER on its Preliminary Determination: Base Year Opex*, 3 July 2015, p. 24.

<sup>108</sup> Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs, 22 April 2015 Report*, p. 19; Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 12 October 2015, p. 8.

<sup>109</sup> AER, *Expenditure Forecast Assessment guidelines for electricity distribution and transmission: Issues Paper*, December 2012. We also specifically asked Ergon Energy to provide information on the costs of the OEFs that it considers affect its network in preparing the preliminary decision: AER, Information request ERG002, 3 December 2014; AER, Information request ERG018.

<sup>110</sup> NEL, ss. 7 and 7A.

<sup>111</sup> NEL, s. 7A(2).

appropriate and sufficiently conservative to avoid the risks of undercompensating Ergon Energy whilst promoting efficient incentives. Further, no evidence before us demonstrates that our approach leads to over-compensating Ergon Energy to the detriment of consumers.

Finally, we have assessed PwC's proposed 21.5 per cent of changes to our OEF assessment. Of this, we have accepted 1.5 per cent. We discuss these changes in our reasons on the economies of scale, bushfire risk, extreme weather, occupational health and safety regulations and solar uptake OEF adjustments.

## **A.6.2 OEF adjustments that we have applied differently from the preliminary decision**

### **Cyclones**

In the preliminary decision we applied a 4.6 per cent OEF adjustment for the network switching and emergency response operation costs that Ergon Energy incurs following a cyclone (cyclone OEF adjustment). This was on the basis that cyclones are beyond Ergon Energy's control, can potentially result in Ergon Energy incurring material costs and are not accounted for in the CD SFA model.<sup>112</sup>

PwC submitted that we should increase the cyclone OEF adjustment for extreme weather events from 3 per cent to 8.1 per cent in light of the costs associated with responding to Cyclone Yasi and Cyclone Oswald.<sup>113</sup>

The cyclone OEF adjustment that we applied in the preliminary decision accounted for Cyclone Yasi but not Cyclone Oswald. For the same reasons we accounted for Cyclone Yasi in the preliminary decision, we agree that we should account for Cyclone Oswald as well. We have accounted for it by increasing the cyclone OEF adjustment from 4.6 to 5.4 per cent. This reflects the \$104 million (2014–15) of opex associated with cyclones that Ergon Energy incurred between 2006 and 2013, which is 3.9 per cent of its network services opex during this period. This is an increase in Ergon Energy's historical opex. In accordance with how we calculate OEF adjustments as discussed in the preliminary decision, this results in a 5.4 per cent increase in the required increase in efficient opex.

We have not increased the OEF adjustment for extreme weather as proposed by PwC. This would double count the effect of Cyclone Oswald.

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<sup>112</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 209 and 210.

<sup>113</sup> PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, pp. 15 and 16.



## Occupation health and safety regulations

In the preliminary decision we applied a 0.5 per cent OEF adjustment for differences in OH&S regulations (OH&S OEF adjustment).<sup>114</sup> This was on the basis that OH&S regulations are beyond Ergon Energy's control, the differences in costs between Ergon Energy and the comparison services providers is material and not accounted for in the CD SFA model. An OH&S OEF adjustment satisfies all of our OEF adjustment criteria.

PwC contended our position in the preliminary decision. PwC submitted that we should apply a 5.2 per cent OH&S OEF adjustment to also account for the differences in the incremental costs of complying with the WHS model laws between:

- the Victorian and Queensland service providers
- single and multi-state businesses and
- networks service providers and generators.<sup>115</sup>

This submission has not caused us to apply a 5.2 per cent OH&S OEF adjustment. However, for the following reasons, we have increased the OH&S OEF adjustment from 0.5 to 1.2 per cent.

First, PwC submitted that the incremental cost of compliance with the WHS model laws was higher in Queensland.<sup>116</sup> However, this negatively affects the OH&S OEF adjustment applied to Ergon Energy. The Victorian OH&S obligations were more costly to comply with prior to the introduction of the WHS model laws in Queensland in January 2013. The Victorian service providers therefore suffered a cost disadvantage in comparison to the Queensland service providers for 93 per cent of the benchmarking sample period. Nevertheless, PwC presented cost impact tables that estimate the costs associated with the changes following the introduction of the WHS model laws. We have not been able to rely on these cost impact tables to quantify an OH&S OEF adjustment.<sup>117</sup>

Second, the OH&S OEF adjustment already accounts for the costs faced by single state businesses. We do not need to change the OH&S OEF adjustment because Ergon Energy only operates in Queensland. Nor do we need to change it to account for

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<sup>114</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 229–231. The quantification was based on PwC's findings. This report was commissioned by the Victorian Government to estimate the cost to the Victorian economy of transitioning to the Work Health and Safety (WHS) Laws that apply in the other NEM jurisdictions: see PricewaterhouseCoopers, *Impact of the Proposed National Model Health Work and Safety Laws in Victoria*, April 2012, p. 7.

<sup>115</sup> PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, pp. 10 and 20.

<sup>116</sup> PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, p. 10.

<sup>117</sup> Each estimate in PwC's cost tables is ranked on an ordinal scale, where the distance between each rank is not comparable. The incomparability of these ranks means that any conclusion drawn by adding these ranks together (as PwC has done and is generally the case with performing arithmetic operations on ordinal data) are not meaningful: see Selvanathan et al., *Australian Business Statistics*, 4th Edition, 2006, pp. 25–28.

differences in incremental costs for complying with the WHS model laws between single state and multi-state service providers. According to PwC, 99 per cent of the incremental costs forecast in the 2012 report are attributable to single state businesses.<sup>118</sup>

Third, we recognise that an electricity distribution network may incur more incremental costs associated with the introduction of the WHS model laws than the average firm. While we did have estimates of the incremental cost impact of complying with the WHS model laws for electricity generators, we did not have this kind of information for an electricity distribution network prior to the preliminary decision.

Using the information presented by PwC, we have calculated an uplift (or risk) factor of 2.6.<sup>119</sup> This differs to PwC's proposed uplift factor of 3. We recognise that this may be generous given the incremental compliance costs of the Victorian generators (who are already compliant with some of the new requirements) would be lower than that of the Queensland generators.<sup>120</sup> That notwithstanding, we consider that a factor of 2.6 reflects a reasonable estimate of the future cost disadvantage that Ergon Energy will face in this regard.

### A.6.3 Other OEF adjustments

#### Customer density

In the preliminary decision we did not apply an OEF adjustment for differences in customer density between service providers (customer density OEF adjustment).<sup>121</sup> This was on the basis that the CD SFA model accounts for customer density by including customer numbers and circuit length as output costs. Statistical analysis undertaken by Economic Insights also indicated that customer density did not account for differences in opex efficiency observed between the distributors.<sup>122</sup>

In support of a customer density OEF adjustment, Huegin submitted that electricity distribution suffers from diseconomies of scale with decreasing customer density.<sup>123</sup> Huegin also submitted that the CD SFA model does not sufficiently account for

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<sup>118</sup> PricewaterhouseCoopers, *Impact of the Proposed National Model Health Work and Safety Laws in Victoria*, April 2012, p. 1.

<sup>119</sup> PwC's factor of 3 based on 10,500 (\$2011) per employee to comply with the model laws. Our factor of 2.6 is based on \$9,239 (\$2011) per employee as calculated by dividing the ongoing incremental cost of compliance of \$42.5 million (\$2011) by the 4,600 Ergon Energy employees: PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, pp. 19 and 20.

<sup>120</sup> PricewaterhouseCoopers, *Occupational health and safety obligations: Ergon Energy – Supporting analysis for submission to the AER*, 1 July 2015, p. 10.

<sup>121</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 174.

<sup>122</sup> Economic Insights, *Economic benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 24.

<sup>123</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination*, July 2015, pp. 43–45.

customer density.<sup>124</sup> These submissions have not caused to depart from our position in the preliminary decision for the following reasons.

First, sparse rural networks do not experience diseconomies of scale. The opex required to service additional route length decreases as route length increases. Whilst low density service providers may experience a cost disadvantage relative to high density service providers in terms of increased travel time, they have the advantage of simpler networks. Simpler networks are generally less expensive to maintain or replace.<sup>125</sup> Asset failure consequences, including the associated safety and reliability risks, are also generally less severe.<sup>126</sup> Inspection cycles can therefore be longer and assets can more often be operated until failure. Installing and maintaining SWER (Single Wire Earth Return) is one example.<sup>127</sup> However, areas of high bushfire risk are an exception. As we discuss below, bushfire risk is lower in Queensland than in Victoria.

Second, the CD SFA model accounts for customer density. It uses customer numbers, circuit length and demand as outputs. The MPFP benchmarking models account for customer density as well because they also use these outputs.<sup>128</sup> The CD SFA model also accounts for the relationship between spatial customer density and opex. This is demonstrated by the results of Economic Insights' translog model that has a more flexible functional form. If costs customer density differences for remote networks were not adequately captured by the CD SFA model, we would expect that the results of the translog model would be significantly different from the CD SFA model.<sup>129</sup> However, the efficiency rankings that result from Economic Insights' translog model are similar to those of the CD SFA model. Further, some of the distributors that perform the worst in Economic Insights' benchmarking models are high density urban distributors.<sup>130</sup> The majority of the comparison firms are low density rural distributors who do not appear to

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<sup>124</sup> Huegin Consulting, *AER Benchmarking of Ergon Energy Opex: Huegin Review of the Preliminary Determination*, July 2015, pp. 15–17.

<sup>125</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 174 and 175; EMCa, *Relationship between Opex and Customer Density for Sparse Rural Networks: Report to Australian Energy Regulator from Energy Market Consulting Associates*, April 2015, pp. 1 and 2.

<sup>126</sup> Gary Humphreys, *Statement of Gary Humphreys - COO Essential Energy*, January 2015, p. 4.

<sup>127</sup> SWER is a simple type of electricity distribution technology that uses a single wire to transport electricity to customers. As only a single wire is used, fewer poles are needed for support and fewer pole top assets are required. It is not uncommon in metropolitan areas for there to be a pole supporting wires up to every 40 meters. Whereas in areas serviced by SWER, it is not uncommon for poles to be spaced more than 300 meters apart. This results in lower pole and pole top asset inspection and maintenance costs. Poles and structure maintenance typically forms the largest part of routine maintenance requirements for distribution feeders, representing roughly 80 per cent of the total maintenance costs of rural distributors: see EMCa, *Relationship between Opex and Customer Density for Sparse Rural Networks: Report to Australian Energy Regulator from Energy Market Consulting Associates*, April 2015, p. 10.

<sup>128</sup> Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 24.

<sup>129</sup> Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, 22 April 2015, p. vii–viii.

<sup>130</sup> Pacific Economics Group, *Statistical Benchmarking for NSW Distributors*, January 2015, p. 65.

be disadvantaged relative to the high density urban distributors. This is consistent the CD SFA model accounting for customer density.

Finally, EMCa has stated that it is feasible to compare the opex of sparse rural distributors to that of other rural distributors provided opex per kilometre decreases with customer density.<sup>131</sup> While EMCa concludes that line length is a reasonable proxy for cost drivers for 60 to 70 per cent of opex for rural distributors, it notes that this simplifies the actual relationship between inputs and outputs. To this end EMCa states:<sup>132</sup>

We consider that the primary cost relationships described above ... should not be construed as the only factors affecting such cost comparisons and we propose these relationships as an adjunct to any quantitative analysis.

EMCa's findings are consistent with our benchmarking analysis.<sup>133</sup> Line length and customer numbers are not the only factors that affect opex.<sup>134</sup> Economic Insights' benchmarking model accounts for demand and the proportion of undergrounding. We have also accounted for a large amount of other cost drivers in our assessment of OEF adjustments.

## Economies of scale and economies of scope

In the preliminary decision, we did not apply an OEF adjustment for differences in economies of scale.<sup>135</sup> This was on the basis that the CD SFA model already accounts for it. The Cobb Douglas function permits the estimation of the cost elasticities of its output variables. An economies of scale OEF adjustment therefore did not satisfy the duplication OEF adjustment criterion. Ergon Energy did not propose an OEF adjustment for differences in economies of scope prior to the preliminary decision.

In support of making an OEF adjustment for economies of scale and economies of scope, PwC submitted that some comparison firms have a cost advantage due to the efficiency savings they realise through sharing corporate overheads and network operations because of their management of multiple electricity networks or multiple infrastructure networks.<sup>136</sup> This submission has not caused us to depart from our position in the preliminary decision not to apply an OEF adjustment for economies of

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<sup>131</sup> EMCa, *Relationship between Opex and Customer Density for Sparse Rural Networks: Report to Australian Energy Regulator from Energy Market Consulting Associates*, April 2015, pp. 1 and 2.

<sup>132</sup> EMCa, *Relationship between Opex and Customer Density for Sparse Rural Networks: Report to Australian Energy Regulator from Energy Market Consulting Associates*, April 2015, p. 8.

<sup>133</sup> Economic Insights, *Response to Consultants' Reports on Economic Benchmarking of Electricity DNSPs*, 22 April 2015, p. 30.

<sup>134</sup> EMCa, *Relationship between Opex and Customer Density for Sparse Rural Networks: Report to Australian Energy Regulator from Energy Market Consulting Associates*, April 2015, p. 8.

<sup>135</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 180.

<sup>136</sup> PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, pp. 8–10.

scale. PwC has not provided us with a reason to suggest that an OEF adjustment of this kind ought to satisfy our duplication OEF adjustment criterion.

For similar reasons, we also have not applied an OEF adjustment for economies of scope. Economies of scope arising from Ergon Energy's management of multiple infrastructure networks through sharing overheads between its jointly owned subsidiary SPARQ Solutions and its wholly owned subsidiary Nexium Telecommunications are the result of endogenous management decisions.<sup>137</sup> An OEF adjustment of this kind does not satisfy the exogeneity OEF adjustment criterion. We are also not aware of any persuasive countervailing factors that would justify not excluding this OEF adjustment.

## Capitalisation practices

In the preliminary decision we accounted for differences arising from capitalisation practices as part of the OEF adjustment we applied for individually immaterial factors. We did this because the CD SFA model does not account for differences arising from capitalisation practices and the associated difference in opex between service providers was not material. Whilst we recognise that these decisions are endogenous to the service provider and would not satisfy our OEF exogeneity criterion, we do not exclude OEF adjustments purely based on the exogeneity criterion if there are persuasive countervailing factors. Under the NER, the capitalisation decisions that a service provider makes in the context of providing standard control services must be in accordance with that service provider's approved CAM.

Cost allocation is not an efficiency consideration. It is not relevant to assessing whether the revealed expenditure in a base year is able to form the starting point of a total forecast that we are satisfied reasonably reflects the opex criteria. For this reason, in the preliminary decision we treated an OEF adjustment that concerns differences in capitalisation practices as satisfying our OEF exogeneity criterion.

## Property portfolios

An OEF adjustment for differences in property portfolios between service providers (property portfolios OEF adjustment) was not proposed to us prior to the preliminary decision. In support of us applying a property portfolios OEF adjustment, Ergon Energy submitted that relative to other distributors, it incurs more costs to maintain its property portfolio in regional areas to provide accommodation for staff that is working away from home.<sup>138</sup> This submission has not caused us to apply a property portfolios OEF adjustment in this final decision for the following reasons.

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<sup>137</sup> SPARQ Solutions, *Welcome to SPARQ Solutions*, available at <https://www.sparq.com.au/> [last accessed 17 July 2015]. AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 113.

<sup>138</sup> Ergon Energy, *Meeting the Rules Requirements*, 31 October 2014, p. 74.

First, the extent to which Ergon Energy decides to invest in property and how it accommodates its staff in rural areas are both endogenous management decisions.

Second, the impact of additional accommodation costs arising from staffing needs in rural areas associated with its property portfolio is a customer density consideration that are already accounted for in the CD SFA model.

Third, in our view, such costs are unlikely to be material. We note that Ergon Energy did not identify the associated opex for property maintenance that it incurs. A property portfolios OEF adjustment therefore does not satisfy any of our OEF adjustment criteria.

## Reliability outcomes

In the preliminary decision we did not apply an OEF adjustment for differences in reliability outcomes between service providers (reliability outcomes OEF adjustment).<sup>139</sup> This was because the CD SFA model already accounts for reliability outcomes and that to some extent reliability outcomes are the result of endogenous management decisions.<sup>140</sup> A reliability outcomes OEF adjustment would not satisfy our duplication and exogeneity OEF adjustment criteria.

Ergon Energy, Jacobs and Synergies contended with our position in the preliminary decision. They raised three main points in support of a reliability outcomes OEF adjustment:

- customers are satisfied with the current level of reliability and are willing to forego decreases in prices to maintain reliability
- our opex forecast will lead to a decrease in reliability performance
- the CD SFA model does not capture reliability outcomes.<sup>141</sup>

These submissions did not cause us to depart from our position in the preliminary decision for the following reasons.

First, the submissions from users generally do not substantiate the argument that they are willing to forego decreases in prices to maintain reliability.<sup>142</sup> Instead, most users

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<sup>139</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 7-186.

<sup>140</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 7-186, 7-187, 7-192 and 7-193.

<sup>141</sup> Ergon Energy, *Revised Proposal: Attachment 0A.01.02*, July 2015, p. 4; Jacobs, *AER Preliminary Decision Response: Ergon Energy Reliability Impact Assessment*, 12 June 2015; Synergies, *Further analysis of Ergon's efficiency in the light of customer consultations*, July 2015, p. 4.

<sup>142</sup> See, for example, Queensland Council of Social Services, *Response to AER Preliminary Decision for Queensland distributors 2015-2020*, July 2015, p. 7: Reviewing user group submissions to the AER, it is very clear that users have expressed a clear preference for lower prices without raising reliability concerns. On Ergon's regulatory proposal, for example, user groups repeatedly criticised the path of high prices over recent years and did not raise concerns about reliability. See also: Alliance of Electricity Consumers; *Submission to the AER's preliminary*

raised issue with the benchmark comparison point we chose, submitting that our benchmark comparison point was too low or that we should have chosen a benchmark comparison point equal to that of the efficient frontier business, CitiPower. We discussed these submissions in section A.4.1 above.

Second, we do not agree that our substitute estimate of the required forecast opex will lead to a decrease in reliability performance. The base year opex upon which our substitute estimate is based on was determined by using the results of our CD SFA model. The CD SFA model is based on comparison firms that provide reliable services at relatively lower cost than Ergon Energy.<sup>143</sup> The expectation of Jacobs that Ergon Energy will reduce its maintenance and emergency response activities in response to our preliminary decision is dependent on decisions by Ergon Energy.<sup>144</sup> It is not an expectation that we share given that we are satisfied our forecast of total required opex reasonably reflects the opex criteria.

Third, we remain of the view that the CD SFA model accounts for reliability outcomes. It does so by accounting for customer density on the basis that the other service providers all provide reliable services. Further, the results of the CD SFA model are consistent with that of Economic Insights' opex MPFP model, which has an output variable for reliability.<sup>145</sup>

## Safety outcomes

In the preliminary decision we did not apply an OEF adjustment for differences in safety outcomes (safety outcomes OEF adjustment).<sup>146</sup> This was based on our assessment that the CD SFA model adequately accounts for safety outcomes and that the comparison firms operate safe networks.<sup>147</sup>

Ergon Energy contended with our position in the preliminary decision. It raised the following points:

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*decision (Queensland)*, 3 July 2015; Canegrowers Isis, *AER Draft Determination : Ergon Energy and Energex – Network Distribution Resets 2015-2020*, 6 July 2015; Chamber of Commerce and Industry Queensland Submission, 3 July 2015; Cotton Australia, *RE: AER Determination Ergon*, 3 July 2015; FNQROC, *Preliminary decision on Ergon Energy's regulatory proposal 2015-20 - FNQROC submission*, July 2015; Queensland Consumers Association, *Submission on AER preliminary determinations for Energex and Ergon Energy Revenues for 2015-20*, 3 July 2015;; Queensland Farmers' Federation, *Submission to the AER on the preliminary determination for the Ergon Energy and Energex regulatory proposals for 2015-2020*, 3 July 2015; Total Environment Centre, *Submission to the AER on the Preliminary Decisions on the QLD DBs' Regulatory Proposals 2015-20*, July 2015.

<sup>143</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 188 and 189.

<sup>144</sup> Jacobs, *AER Preliminary Decision Response: Ergon Energy Reliability Impact Assessment*, 12 June 2015, p. 15.

<sup>145</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 186.

<sup>146</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 195 and 196.

<sup>147</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 195.

- the Victorian service providers were unsafe prior to Black Saturday
- we should have had regard to more measures of safety, including investigating public liability insurance levels, legal actions or fatalities related to the distributors' asset management practices and public liability insurance costs
- we should have clearly identified how service providers allocate capital and operating expenditure in respect of safety outcomes.<sup>148</sup>
- These submissions did not cause us to depart from our position in the preliminary decision for the following reasons.

First, we do not agree that the Victorian service providers were unsafe prior to Black Saturday. On the safety measures that are available to us, the Victorian service providers appear to perform as well as or better than other service providers. Further, as we noted in the preliminary decision, Energy Safe Victoria (ESV) has consistently found that the Victorian service providers are generally compliant with their safety obligations.<sup>149</sup> Ergon Energy did not provide any evidence to refute the similar conclusions of the independent audits conducted prior to the Black Saturday bushfires. Those audits concluded that SP AusNet and Powercor were generally compliant with their safety obligations. We also note that the Victorian Bushfire Royal Commission's (VBRC) final report recommendations (which relate only to Powercor and AusNet Services) contemplated certain asset replacements. Ergon Energy did not provide any evidence to refute that the total forecast capex allowance that we determined for the Victorian distributors for the 2010–15 regulatory control period was insufficient in this regard.<sup>150</sup>

Second, we do not accept that we should have had regard to more safety measures in setting OEFs. This assumes that we have not already had proper regard to safety outcomes. We took into account findings from the ESV, lost time injury frequency rate (LTIFR) data, data on fire starts caused by vegetation contact and the number of fatalities due to contact with electrical assets.<sup>151</sup> We also investigated whether we

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<sup>148</sup> Ergon Energy, *Submission on the Queensland Revised Regulatory Proposals*, 24 July 2015, pp. 10–27.

<sup>149</sup> These obligations include providing to ESV an Electricity Safety Management Scheme pursuant to Part 10 of the *Electricity Safety Act 1998* (Vic), a Bushfire Mitigation Plan and an Electric Line Clearance Management Plan. See AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 7-195–7-197; ESV, *Safety performance report on Victorian Electricity Networks 2013*, June 2014, p. 5.

<sup>150</sup> IJM Consulting, *Bushfire Mitigation Powercor Australia: Final Audit Report 2008, Audit Report*, pp. 17-20; VBRC, *Final Report Recommendations*, 2009, p. 2. The repex model that we applied in determining the total forecast capex allowance for the Victorian distributors takes into account their specific circumstances and the rate at which their assets fail.

<sup>151</sup> Findings of the ESV suggested that the Victorian service providers are generally safe. The LTIFR data we took into account, which is likely to provide a fair comparison between Ergon Energy and the comparison firms, suggested to us that the majority of the comparison firms will have a lower LTIFR than Ergon Energy. This is because CitiPower and Powercor's LTIFR is likely to be lower than presented but this is offset by the fact that AusNet Services and SA Power Networks' LTIFR should be slightly higher. AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, p. 198; As to the number of fatalities due to contact with electrical assets, this may reflect considerations other than the safety of service



could compare serious electrical incident data and total fire starts related to network assets. We were unable to make these comparisons because of differences in reporting methodologies and the availability of consistent data across service providers. It is difficult to draw any meaningful conclusions from comparing public liability insurance levels, legal actions or fatalities related to the distributors' asset management practices and public liability insurance costs. Such comparisons are likely to reflect differences in circumstances and risks that are not relevant to differences in safety outcomes.

Third, we have considered the capex/opex trade-offs in capitalisation practices. For the purposes of our assessment of Ergon Energy's total forecast opex, it is not necessary to consider the capex/opex trade-offs at each category level. While a firm may capitalise more of its costs in certain areas, this may be offset in other areas where they expense more of their costs. In any case, at the total level, the other service providers tend to expense more of their costs than Ergon Energy. This puts the other service providers at a disadvantage in relation to claims for more revenue based on capitalisation practices.

## Bushfire risk

In the preliminary decision we applied a –2.6 per cent OEF adjustment for differences in bushfire risk between service providers (bushfire OEF adjustment).<sup>152</sup> We did this because of our assessment of the differences in the impact of bushfires in Queensland, South Australia and Victoria and the costs associated with changes to vegetation management and other bushfire related regulations in Victoria. While service providers can take action to manage their bushfire risk, the natural environment and regulations with which they must comply are generally beyond their control. The CD SFA model does not account for bushfire risk. In our view, the difference in opex associated with bushfire risk and vegetation management regulations between Ergon Energy and the comparison firms is material. A bushfire OEF adjustment satisfies all of our OEF adjustment criteria.

Ergon Energy, Huegin and PwC contended our position in the preliminary decision. They raised the following points:

- there are more bushfire hotspots in Queensland than in Victoria

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providers' networks: Ergon Energy, *Sustainability Report 2006/07*, 2007, p. 62; Ergon Energy, *Annual Stakeholder Report 2008/09*, p. 44; Ergon Energy, *Annual Stakeholder Report 2009/10*, 2010, p. 34; Ergon Energy, *Annual Stakeholder Report 2010/11*, 2011, p. 46; Ergon Energy, *Annual Stakeholder Report 2011/12*, 2012, p. 21; Ergon Energy, *Annual Stakeholder Report 2012/13*, 2013, p. 19; ESV, *Annual Safety Performance Report 2013*, 2014, p. 14; ESV, *Annual Safety Performance Report 2012*, 2013, p. 17; ESV, *Annual Safety Performance Report 2011*, 2012, p. iv.

<sup>152</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 200–209.

- Ergon Energy spends as much on bushfire mitigation as the Victorian service providers do and the vegetation management clearances they must maintain are similar
- the Victorian service providers spent an inefficiently low level of opex on bushfire mitigation prior to the change in regulations in Victoria following Black Saturday.<sup>153</sup>

These submissions did not cause us to depart from our position in this preliminary decision for the following reasons.

First, Victoria has the highest risk of bushfire of any State or Territory in Australia. It is one of the most bushfire prone areas in the world.<sup>154</sup> It follows that the expected costs associated with bushfires is greater in Victoria.<sup>155</sup> In our view, an average of the historical costs associated with bushfires is a good indicator of their expected costs, in terms of the probability (frequency) of a bushfire occurring and its severity. On this basis, the average annual cost of bushfires in Victoria is more than 221 times greater than that in Queensland.<sup>156</sup> We note that a number of statements previously expressed by Ergon Energy also support our view. For example:

Since the catastrophic Victorian ‘Black Saturday’ bushfires of 2009, there has been increased pressure for electrical DNSPs such as Ergon Energy to provide greater reassurance to the public that all practicable efforts are made to prevent the ignition of bushfires. While the risk of such catastrophic fires occurring within Ergon Energy’s network area is much lower than in other regions of Australia, Ergon Energy has a responsibility to manage any bushfire risks associated with its network.<sup>157</sup>

... [and the risk associated with vegetation management and access tracks] is inherently lower than may be experienced in other parts of Australia. This ... point is primarily due to low population density and the lower likelihood of a severe bushfire occurring within locations covered by the network.<sup>158</sup>

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<sup>153</sup> Huegin Consulting, *AER Operating Environment Factors: Huegin review of the bushfire factor*, 21 July 2015, pp. 3 and 4; Ergon Energy, *Submission on the Queensland Revised Regulatory Proposals*, 24 July 2015, pp. 20–24; Ergon Energy, *Submission on the Queensland Revised Regulatory Proposals*, 24 July 2015, p. 15.

<sup>154</sup> ESV, *Regulatory Impact Statement: Electric Line Clearance Regulations 2010*, p. 65. Further, normalising for differences in population size, bushfires are 11 times more likely to cause death in Victoria than in Queensland: Haynes, K. et al., *Australian bushfire fatalities 1900–2008: exploring trends in relation to the ‘prepare, stay and defend or leave early’ policy*, Environmental Science & Policy, vol. 13 no. 3, May 2010, p. 188; 3105.0.65.001 - Australian Historical Population Statistics, 2014. The average annual economic cost of bushfires was 221 times higher in Victoria than in Queensland between 1967 to 2009 (assuming no bushfire related costs between 2000 and 2008): Stephenson, C., Handmer, J., and Haywood, A., *Estimating the net cost of the 2009 Black Saturday Fires to the affected region*, February 2012, p. 6; BTE, *Economic costs of natural disasters in Australia*, 2001, p. 35; ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13; ABS, 6401.0 - Consumer Price Index.

<sup>155</sup> In our view, the appropriate measure of risk is expected cost. Expected cost is a measure of the likelihood and the severity of an adverse event. See Binger, B. and Hoffman, E., *Microeconomics with Calculus*, 1998, p. 513.

<sup>156</sup> Stephenson, C., Handmer, J., and Haywood, A., *Estimating the net cost of the 2009 Black Saturday Fires to the affected region*, February 2012, p. 6; BTE, *Economic costs of natural disasters in Australia*, 2001, p. 35; ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13; ABS, 6401.0 - Consumer Price Index.

<sup>157</sup> Ergon Energy, *Vegetation & Access Track Management Strategy: 2015-20*, 2014, p. 38.

<sup>158</sup> Ergon Energy, *Vegetation & Access Track Management Strategy: 2015-20*, 2014, p. 23.

... while there are SWER lines in Ergon Energy's network, they pose little hazard to the public because the risk profile for bushfire is very low in this region. If poles and conductors come down, they do not tend to start bushfires. This highlights a need for recognition, particularly by the national regulator, of differing bushfire risk profiles, relevantly in South-eastern Australia, which are not present in other areas of the country.<sup>159</sup>

Second, we do not agree that Ergon Energy spends as much on bushfire mitigation as the Victorian service providers do. It is difficult to determine definitively the extent to which vegetation management practices differ between Ergon Energy and the Victorian service providers. However, in our view, the requirements specified in the relevant regulations in Victoria are more onerous than in Queensland. Ergon Energy is required to keep vegetation clear from network assets where it is likely to cause injury or damage to property whereas the Victorian service providers are required to comply with prescribed minimum clearance distances.<sup>160</sup> Notably, audits prior to Black Saturday generally found that the Victorian distributors were generally compliant with their bushfire mitigation and vegetation management requirements.<sup>161</sup> An analogous observation is difficult to make for Ergon Energy in circumstances where its vegetation management requirements are less prescriptive. It is also difficult because of the following statement made by Ergon Energy:

Prior to 2005, there was little knowledge of vegetation and access track condition, and the maintenance history. During the early years of the regulatory control period 2005 to 2010, the program was highly reactive, with inadequate funding to maintain vegetation clearances along the entire network. Work focussed on poor performing feeders where vegetation incidents were prevalent. However, this was not preventative in nature, and so maintenance costs and risk exposure escalated across the network.<sup>162</sup>

The extent of Ergon Energy's compliance with its own internal vegetation management standards and the arguably less prescriptive circumstances in Queensland supports the conclusion that the Victorian service providers spend more than Ergon Energy does on bushfire mitigation. This is also consistent with our observation that AusNet Services (who has a similar capex/opex ratio to Ergon Energy) appears to undertake proportionally more asset replacement than Ergon Energy.<sup>163</sup> Further, we note that the Victorian service providers were previously able to seek to be exempt, in certain circumstances, from complying with their vegetation management requirements. The

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<sup>159</sup> VBRC, *Outline of Evidence - Kim Griffith: EVI.001.001.0001*, 11 May 2009, p. 2.

<sup>160</sup> *Electrical Safety Regulation 2013* (Qld), s 79; *Electricity Safety (Electric Line Clearance) Regulations 2015* (Vic), Schedule (Code of Practice for Electric Line Clearance), cl. 3 and Part 3; *Electricity Safety (Electric Line Clearance) Regulations 2010* (Vic), reg. 7, Schedule (Code of Practice for Electric Line Clearance), cl. 2(1) and 10.

<sup>161</sup> IJM Consulting, *Bushfire Mitigation Powercor Australia: Final Audit Report 2008*, Audit Report, pp. 17–20.

<sup>162</sup> Ergon Energy, *Vegetation & Access Track Management Strategy: 2015-20*, 2014, p. 20. See also Huegin, *AER Operating Environment Factors: Huegin review of the bushfire factor*, 21 July 2015, p. 9.

<sup>163</sup> For all of the categories analysed, except for one, AusNet Services has proposed to undertake more asset replacement than Ergon Energy, even before considering the relative size of the networks: Ergon Energy, *Submission on the Queensland Revised Regulatory Proposals*, 24 July 2015, pp. 20-24. AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 181 and 182.

ability to seek such exemptions ceased in 2010. This has increased the cost of the Victorian service providers' vegetation management practices.<sup>164</sup>

Third, we do not agree that the Victorian service providers spent an inefficiently low level of opex prior to the change in regulations in Victoria following Black Saturday. The change in regulations, which the higher expenditures for bushfire mitigation of the Victorian service providers were in response to, is attributable to a revised assessment by both the Victorian Government and insurers that bushfire risks in Victoria were greater than previously thought.<sup>165</sup> This is not attributable to any perceived imprudence or inefficiency on the part of the Victorian service providers. The information available to us indicates that the Victorian service providers were meeting their bushfire mitigation responsibilities prior to 2009 and have continued to do so.<sup>166</sup> In particular, the ESV has not concluded that any of the Victorian service providers have operated unsafe networks.<sup>167</sup> In respect of Powercor and AusNet Services, the findings of the VBRC also did not conclude that they operated unsafe networks. In our view, the VBRC's findings that Powercor and AusNet Services had foregone opportunities to improve their safety practices do not support this conclusion.<sup>168</sup> Further, we note that the bushfire risks in Victoria were considered higher than in Queensland prior to Black Saturday.<sup>169</sup> More often than not, higher risks are justifiably associated with higher

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<sup>164</sup> CitiPower and Powercor Australia, *Response to AER Queries Received 8 January 2015*, 30 January 2015, p. 3; United Energy, *Response to request for Information on Bushfire Regulations and Opex Productivity*, 23 January 2015, p. 5; AusNet Services, *Response to AER bushfire regulation and productivity info request*, 23 January 2015, p. 2; Jemena, *Response to questions concerning bushfire regulations and productivity*, 3 February 2015, p. 18.

<sup>165</sup> AER, *Final decision: CitiPower Ltd and Powercor Australia Ltd vegetation management forecast operating expenditure step change*, August 2012, p. 2; AER, *CitiPower Pty Distribution determination 2011-15*, September 2012, p. 17; AER, *Powercor Australia Ltd Distribution determination 2011-15*, October 2012, p. 26; AER, *Final decision: Powercor cost pass through application of 13 December 2011 for costs arising from the Victorian Bushfire Royal Commission*, May 2011, p. 96; AER, *Final decision - appendices: Victorian electricity distribution network service providers - Distribution determination 2011-2015*, October 2011, pp. 301–304; AER, *Final Decision: SP AusNet cost pass through application of 31 July 2012 for costs arising from the Victorian Bushfire Royal Commission*, 19 October 2012, p. 3; AER, *SPI Electricity Pty Ltd Distribution determination 2011-2015*, August 2013, p. 20; AER, *Jemena Electricity Network (Victoria) Ltd: Distribution determination 2011-2015*, September 2012, p. 22; AER, *United Energy Distribution: Distribution determination 2011-2015*, September 2012, p. 19; AER, *Final decision - appendices: Victorian electricity distribution network service providers - Distribution determination 2011–2015*, October 2011, pp. 313–319; Powercor, *Regulatory Proposal 2011-15*, 30 November 2009, p. 167.

<sup>166</sup> IJM Consulting, *Bushfire Mitigation Powercor Australia: Final Audit Report 2008, Audit Report*, pp. 17–20.

<sup>167</sup> In fact, the ESV has found that the Victorian DNSPs had comprehensive Electricity Safety Management Systems; that asset maintenance was adequate for the 2013-2014 bushfire season, with no areas of non-compliance observed; that overall management of the Victorian networks in 2012 was good (apart from some asset replacement issues); that the safety performance of the Victorian networks in 2011 was consistent with the performance of networks elsewhere in Australia; and that in 2010 there was a good overall standard of inspection and timely repair: AER, *Final Determination: Ausgrid distribution determination 2015–16 to 2018–19 Attachment 7 – Operating expenditure*, April 2015, pp. 211–213.

<sup>168</sup> Victorian Bushfires Royal Commission, Report: Volume II, 2009, pp. 160 and 161.

<sup>169</sup> Further, prior to Black Saturday, the average economic cost of bushfires in Victoria was 81 times greater than the economic losses than in Queensland: BTE, *Economic costs of natural disasters in Australia*, 2001, p. 35; ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13; ABS, 6401.0 - Consumer Price Index. If the

expenditures. Ergon Energy's Corporate Risk Assessment acknowledges this as well.<sup>170</sup> It follows that it would be inefficient for Ergon Energy to spend as much as the Victoria service providers on bushfire mitigation.

## Solar uptake

In the preliminary decision we included differences arising from the high uptake of solar photovoltaic (PV) installations as part of the OEF adjustment we applied for individually immaterial factors. This was on the basis that solar uptake is beyond Ergon Energy's control, the CD SFA model does not account for solar uptake and the opex associated with differences arising from solar uptake was not material.<sup>171</sup>

PwC submitted that the impact of PV installations on SA Power Network's capex suggested that differences in the uptake of PV would lead to material differences in opex between service providers.<sup>172</sup> This submission has not caused us to depart from our position in this preliminary decision for the following reason.

The impact of solar uptake on capex is not indicative of the impact it would have on opex. Information we sought on the impact of solar uptake on its network from SA Power Networks reveals that the administration of solar PV connections and solar PV related voltage complaints accounted for less than 0.5 per cent of network services opex.<sup>173</sup> In any case, 0.5 per cent of network services opex is 8 times lower than the 4 per cent estimated by PwC.<sup>174</sup> In our view, it follows that the differences in opex associated arising from solar uptake is not material.

## Subtransmission network configuration

In the preliminary decision we applied a 4.6 per cent OEF adjustment for differences in subtransmission network configuration.<sup>175</sup> We did this because of our assessment that

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impact of the Black Saturday bushfires is included, the average annual economic cost is 221 times higher in Victoria than in Queensland: Stephenson, C., Handmer, J., and Haywood, A., *Estimating the net cost of the 2009 Black Saturday Fires to the affected region*, February 2012, p. 6; BTE, *Economic costs of natural disasters in Australia*, 2001, p. 35; ABS, 5220.0 - Australian National Accounts: State Accounts, 2012–13; ABS, 6401.0 - Consumer Price Index.

<sup>170</sup> Ergon Energy, *Regulatory Proposal: Attachment 07.09.30*, 31 October 2014, p. 3. Relevantly, Ergon Energy states that '[d]ue to the low likelihood of weather and fuel conditions facilitating extreme or catastrophic fire danger in areas covered by the Ergon Energy network, bushfire mitigation is not as significant driver of the vegetation management or access track programs as for other distribution network service providers': Ergon Energy, *Vegetation & Access Track Management Strategy: 2015-20*, 2014, p. 19.

<sup>171</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 246 and 247.

<sup>172</sup> PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, p. 12.

<sup>173</sup> SA Power Networks, *Response to information request AER SAPN 018*, 30 January 2015, p. 2.

<sup>174</sup> PricewaterhouseCoopers, *Operating Environment Factors, Ergon Energy: Supporting analysis for submission to the AER*, 1 July 2015, p. 12.

<sup>175</sup> AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20 Attachment 7 – Operating expenditure*, April 2015, pp. 156–159.

Ergon Energy operates proportionally more subtransmission assets than the comparison firms. The boundary between transmission and distribution networks is the result of historical decisions made by state governments. The CD SFA model does not account for differences in subtransmission network configurations. In our view, the difference in the opex associated with differences in subtransmission network configurations between Ergon Energy and the comparison firms is material. An OEF adjustment of this kind satisfies all of our OEF adjustment criteria.

PwC submitted that the amount of overhead subtransmission assets will increase Ergon Energy's costs.<sup>176</sup> We have previously considered this submission.<sup>177</sup> It is more appropriate to use total subtransmission line length to calculate this OEF adjustment. Subtransmission line length is a proxy for the size of the subtransmission network that service providers must operate. This includes switchgear and transformers. Only considering underground subtransmission line length does not properly reflect the differences in subtransmission network configurations. Further, the CD SFA model includes a variable that accounts for differences in the proportion of undergrounding. For these reasons, we have not departed from our position in the preliminary decision.

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<sup>176</sup> PricewaterhouseCoopers, *Labour Expenditure Review*, 1 July 2015, p. 11.

<sup>177</sup> AER, *Final Determination: Ausgrid distribution determination 2015–16 to 2018–19 Attachment 7 – Operating expenditure*, April 2015, pp. 265 and 266.

## B Rate of change

Our forecast of total opex includes an allowance to account for efficient changes in opex over time.

There are several reasons why opex that reflects the opex criteria for each year of a regulatory control period might differ from expenditure in the base year.

As set out in the Expenditure forecast assessment guideline (the Guideline), we have developed an opex forecast incorporating the rate of change to account for the following factors:<sup>178</sup>

- price growth
- output growth
- productivity growth.

This appendix contains our assessment of the opex rate of change for developing our forecast of total opex.

### B.1 Position

We have applied the same rate of change methodology to derive our alternative estimate of opex as we used in our preliminary decision. Table B.1 shows our final position on each rate of change component and the overall rate of change in annual percentage terms. We do not agree with Ergon Energy's criticisms of our rate of change approach.

We have updated our estimate of the rate of change in opex to:

- reflect the most recent forecasts of wage growth in the Queensland utilities industry from Deloitte Access Economics and PricewaterhouseCoopers
- remove an outlier in 2015–16 customer growth numbers due to a transition from historical to forecast data
- update our output growth forecast to reflect updated maximum demand data provided by Ergon Energy

The net impact of these changes results in an annual rate of change that is on average 0.25 per cent higher than our preliminary decision rate of change estimate.

In total our average rate of change from 2014–15 to 2019–20 is 1.76 per cent. In cumulative terms, there is not a material difference between Ergon Energy's and our overall rate of change estimate over the 2015–20 regulatory control period.

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<sup>178</sup> AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

**Table B.1 Rate of change (per cent)**

	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20
<b>Ergon Energy revised proposal</b>						
Price growth	0.63	0.69	0.77	0.77	0.77	0.77
Output growth	1.62	1.44	1.36	1.21	1.18	1.34
Productivity growth	0.00 <sup>179</sup>	0.75	0.75	0.75	0.75	0.75
<b>Overall rate of change</b>	<b>2.26</b>	<b>1.38</b>	<b>1.37</b>	<b>1.22</b>	<b>1.19</b>	<b>1.35</b>
<b>AER</b>						
Price growth	0.35	0.34	0.26	0.38	0.47	0.57
Output growth	1.26	1.19	1.48	1.30	1.62	1.35
Productivity growth	–	–	–	–	–	–
<b>Overall rate of change</b>	<b>1.60</b>	<b>1.53</b>	<b>1.74</b>	<b>1.69</b>	<b>2.10</b>	<b>1.92</b>

Source: Ergon Energy revised proposal, Response to information request 87, Ergon Energy's opex model and AER analysis.

## B.2 Preliminary position

For our preliminary decision, we did not adopt Ergon Energy's forecast change in price, output and productivity in our forecast rate of change and thus our alternative estimate of opex. Our preliminary position for each rate of change component is outlined below

- **Price growth:** for labour price growth we adopted an average of Deloitte Access Economics' (DAE) and Energex's consultant PricewaterhouseCoopers' wage price index (WPI) forecast for the Queensland electricity, gas, water and waste services (EGWWS) industries. For non-labour we adopted the forecast change in the CPI. We applied Economic Insights' benchmark weightings for labour and non-labour.
- **Output growth:** we applied the weighted average forecast change in customer numbers, circuit length and ratcheted maximum demand from Ergon Energy's reset RIN. We based the weights of each of these outputs on Economic Insights' opex cost function analysis.
- **Productivity growth:** we applied a zero per cent productivity growth estimate. We based this estimate on our considerations of recent productivity trends and whether this would be applicable to the forecast period. This was also consistent with Economic Insights' recommendations.

<sup>179</sup> Ergon Energy proposed a 0.75 per cent productivity adjustment for the forecast period therefore it does not apply to 2014–15. However Ergon Energy has applied a ten per cent productivity adjustment to overheads in 2013–14 base year.



Refer to section B.4 of attachment 7 in our preliminary decision for a detailed explanation of our considerations.

## B.3 Revised proposal and submissions

We have maintained the methodology we used in our preliminary decision regarding the forecast rate of change.

Ergon Energy raised concerns regarding the price growth<sup>180</sup> and output growth<sup>181</sup> components of our rate of change forecasting approach. Ergon Energy also did not understand why we did not adopt its rate of change estimate given the small differences in the outcome.<sup>182</sup>

Further, Ergon Energy reduced its forecast productivity growth from 1 per cent per annum to 0.75 per cent per annum. Ergon Energy did not provide a reason for this change in its revised proposal.<sup>183</sup> However, this increase to the rate of change is offset by Ergon Energy's decrease in its labour forecasts. Although Ergon Energy's labour price growth consultant Jacobs provided updated labour forecasts, it did not provide an updated report explaining why it had changed its forecasts.<sup>184</sup>

We also received a submission from the Consumer Challenge Panel (CCP) which considered our rate of change was too high relative to our Energex and SA Power Networks preliminary decisions.<sup>185</sup> We have addressed the CCP's concerns below.

### B.3.1 Labour price growth

We have maintained our labour price growth approach of adopting a forecast of the utilities sector wage price index (WPI). We do not consider the average weekly ordinary time earnings (AWOTE) is a reasonable measure of forecast labour price growth.

Ergon Energy considered our labour price growth methodology is no improvement over its own.<sup>186</sup> It considered forecasts from its consultant Jacobs more closely aligned with Ergon Energy's labour costs.<sup>187</sup> Ergon Energy's revised proposal did not address our concerns with the use of AWOTE to forecast labour price growth.

In our preliminary decision we noted that the AWOTE is more volatile than the WPI because it includes the impact of compositional productivity. That is, it captures the

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<sup>180</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, pp. 10–12.

<sup>181</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 12.

<sup>182</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 9.

<sup>183</sup> Ergon Energy, *06.01.01 Operating expenditure summary operating costs*, 30 June 2015, p. 17

<sup>184</sup> Ergon Energy, *06.02.07 Jacobs addendum cost escalation factors 2015–20*, March 2015.

<sup>185</sup> Consumer challenge panel, *CCP2 panel submission AER preliminary 2015–20 revenue determinations Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 54.

<sup>186</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 11

<sup>187</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 11

price impact of using more or less higher skilled labour.<sup>188</sup> We note that the WPI is the preferred measure of labour price growth over the AWOTE for all distributors that have proposed a utilities sector price growth measure. Energex,<sup>189</sup> United Energy,<sup>190</sup> AusNet Services<sup>191</sup> and all NSW/ACT distributors<sup>192</sup> each proposed the WPI.

We also note the difference between the two labour price growth measures does not materially impact the rate of change once productivity is taken into account. This is because Ergon Energy's labour price increases are offset by a labour productivity forecast of 0.75 per cent.<sup>193</sup>

### B.3.2 Price weightings

We weight the forecast price growth to account for the proportion of opex that is labour and non-labour. We adopted a 62 per cent weighting for labour and 38 per cent for non-labour. We forecast the labour component based on the EGWWS and we base the non-labour component on the CPI. These weightings are consistent with the weightings used in Economic Insights' benchmarking analysis.

Ergon Energy considered that the efficient split between labour and non-labour is likely to have changed over time for Victorian distributors. Ergon Energy also raised other issues, such as operating environment factors, different accounting treatments and approach to contracting services, but did not explain how these affected price weightings.<sup>194</sup>

Ergon Energy adopted the following opex price weightings:

- labour – 36.7 per cent
- contracted services – 35.8 per cent
- materials –27.5 per cent<sup>195</sup>

What we have included as labour is different to what Ergon Energy has included as labour. Our labour component includes both labour directly employed by a benchmark efficient service provider and contracted labour employed to provide field services. We do not include labour employed by contractors who provide non-field services in the labour weighting. Non-field services include services such as legal, accounting, IT and

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<sup>188</sup> AER, *Preliminary decision attachment 7*, April 2015, p. 288

<sup>189</sup> Energex, *Application of base-step-trend AER determination 2015–20*, October 2014, p. 26.

<sup>190</sup> United Energy, *Operating expenditure overview*, 30 April 2015, p. 20

<sup>191</sup> AusNet Services, *Electricity distribution price review 2016–20*, 30 April 2015, p. 188

<sup>192</sup> ActewAGL, *Regulatory proposal 2015–19, 2 June 2014*, p. 226. Ausgrid, *Regulatory proposal 1 July 2014 to 30 June 2019*, 30 May 2014, p. 41, Endeavour Energy, *Regulatory proposal to the Australian Energy Regulatory 1 July 2015 – 30 June 2019*, 30 May 2014, p. 90, Essential Energy, *Regulatory proposal 1 July 2014 to 30 June 2019*, 31 May 2014, p. 75, Independent Economics, *Labour cost escalators for NSW, the ACT and Tasmania*, 18 February 2014, p. iii.

<sup>193</sup> Ergon Energy, *06.01.01 Forecast expenditure summary – operating costs*, 30 June 2015, p. 17.

<sup>194</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 11.

<sup>195</sup> Ergon Energy, *Response to information request 87*, 26 August 2015, p. 3.

other administrative services that are not unique to providing electricity distribution services. We base this classification on Economic Insights' recommended approach to classifying labour and non-labour.<sup>196</sup>

We define labour in this way so we only include the productivity related to providing field services in the productivity component of the opex cost function. This is true for both our measurement of historic productivity change and the forecast productivity change in our opex forecast. We do this because when we measure historic productivity change we are interested in the productivity change achieved by the service providers rather than the productivity change achieved by contractors providing services that are not unique to electricity distribution.

In response to submissions from SA Power Networks, Ergon Energy and the CCP we have investigated whether we could update the benchmark weightings. To do so we considered opex data from a sample of the most efficient service providers according to our opex benchmarking analysis, specifically:

- AusNet Services
- CitiPower
- Jemena
- Powercor
- SA Power Networks
- United Energy

We assessed the proportion of the total opex of these service providers that was labour, contracts and other. That is, we divided the labour opex of the six service providers by their combined total opex for 2014.<sup>197</sup> We did the same for contracts and other. The resulting weights are in Table B.2.

**Table B.2 Opex price weightings (per cent)**

	Labour	Contracts	Other
Ergon Energy	37	36	28
Benchmark	43	40	17

Source: Ergon Energy, Response to information request 87, 26 August 2015, p. 3; AER analysis.

However, we note that the data available to us does not differentiate between expenditure for contracts that provide field services and contracts that provide non-field

<sup>196</sup> Economic Insights, *Response to Ergon Energy's consultants' reports on economic benchmarking*, 7 October 2015, p. 30.

<sup>197</sup> We used 2013–14 for SA Power Networks, which operates on a financial year basis.

services. Further, for those contracts that provide field services, only the labour-related expenses attributable to these contracts should be allocated to the labour price weighting. Consequently, the 2014 data provided by the service providers only enables us to identify that the labour weighting should be somewhere between 43 per cent and 83 per cent. The 62 per cent weight for labour is in the middle of the estimated 43 per cent to 83 per cent labour weighting range. In the absence of more precise information we are satisfied that the 62 per cent weighting for labour remains appropriate.

Ergon Energy considered over 70 per cent of its opex should be escalated by a labour price measure because both its internal labour and contract costs are influenced by labour price growth.<sup>198</sup>

We consider that we should not use a service provider's own base year opex price weightings to forecast price change. Doing so would provide the service provider an incentive to use more than the efficient proportion of internal labour in the base year to increase its forecast price change. Consequently we cannot assume an individual service provider's opex price weightings are efficient, even if our benchmarking analysis finds the service providers base opex to be efficient.

Notwithstanding this, we do not consider our approach is necessarily detrimental to Ergon Energy. Ergon Energy identified its contracts related to vegetation contractors and is largely made up of labour.<sup>199</sup> We consider a vegetation management provider's own costs are likely to include non-labour costs. For example, vegetation contractors will have non-labour costs such as expenditure on vehicles and tree cutting equipment. If 70 per cent of a vegetation management contractor's costs relate to labour then Ergon Energy's internal labour plus the labour component of its contracts would be equal to 62 per cent.

We also examined Ergon Energy's actual vegetation management costs to verify Ergon Energy's claim that its vegetation management costs are linked to labour indices. To do this we compared Ergon Energy's actual audited vegetation management costs reported in the Category Analysis RIN to the utilities sector WPI.

Figure B.1 shows that once we have normalised for vegetation management quantity the real vegetation management costs per km of maintenance spans has not moved in line with labour price increases in the current regulatory control period. Between 2010–11 to 2013–14 the average real increase in utilities sector wages was 1.49 per cent. This indicates that there is no a clear relationship between Ergon Energy's vegetation management costs and labour price growth.

If vegetation management costs were substantially linked to labour price indices then we would expect it would have increased in the current period. There is no evidence of this. Labour price growth is just one factor that influences the overall cost of the contract. For instance, labour price increases could be offset by other factors such as

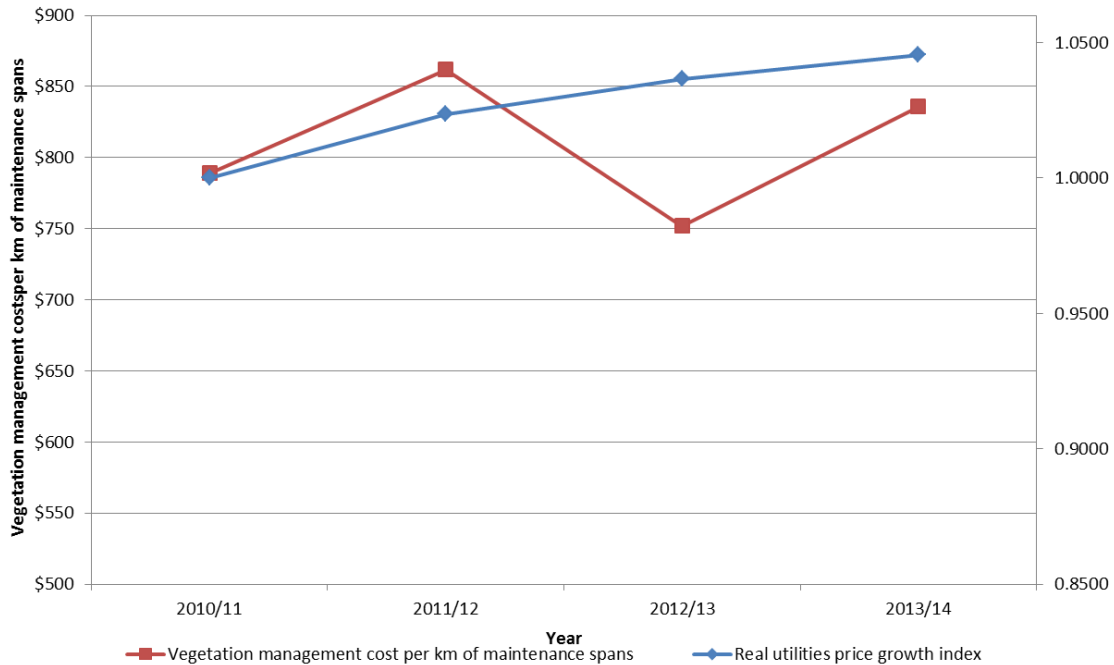
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<sup>198</sup> Ergon Energy, *Response to information request 87*, 26 August 2015, p. 3.

<sup>199</sup> Ergon Energy, *Response to information request 87*, 26 August 2015, p. 3.

productivity improvements made by Ergon Energy's contractors. Ergon Energy does not employ the workers directly. It pays for a vegetation management service.

**Figure B.1 Total vegetation management costs 2009 to 2014 (\$2014) and real utilities sector price growth index**



Source: Category analysis RIN data, AER analysis, ABS 6345.0 Table 9b and 6401.0.

### B.3.3 Output growth

We have maintained our preliminary decision methodology to forecast output growth consistent with our economic benchmarking analysis.<sup>200</sup> We note that there is no material difference between Ergon Energy's forecast output growth and our own. We have also updated our ratcheted maximum demand estimate to reflect new data from Ergon Energy.

In our preliminary decision we noted that ratcheted maximum demand represents the actual capacity a service provider must have to meet its customer's needs whereas zone substation capacity and transformers represent the amount of infrastructure a service provider must build to meet capacity.<sup>201</sup>

Ergon Energy did not agree with our approach of using ratcheted maximum demand to measure capacity. Ergon Energy considered that installed power transformer capacity

<sup>200</sup> AER, *Preliminary decision attachment 7*, April 2015, p. 291

<sup>201</sup> AER, *Preliminary decision attachment 7*, April 2015, p. 294

and the number of distribution transformers was a better measure of the amount of maintenance required on these assets.

Our measure is a demand side measure and represents an increase in services for customers. Meanwhile a supply side measure may reflect the number of assets Ergon Energy maintains but it does not necessarily align with an increase in service to customers. For instance, if a service provider built additional capacity that customers do not require then its customers will have to pay more for maintenance even though they would not receive a greater level of service.

The CCP considered ratcheted maximum demand a better measure than installed capacity because it takes into account the actual network capacity used. The CCP considered this was important because there was growing level of excess network capacity.<sup>202</sup>

We consider our measure better reflects the opex objective to meet or manage the expect demand for standard control services over the regulatory control period.<sup>203</sup> This is because customers should not have to pay more if expected demand remains the same.

We have also reviewed our output growth figures and made the following two adjustments to our output growth data:

- Changed customer growth in 2014–15 from 0.38 per cent to 1.62 per cent. We consider the transition from benchmarking RIN data to reset RIN data resulted in an outlier. We consider 1.62 per cent is more in line with Ergon Energy's trend in customer growth.<sup>204</sup>
- Ergon Energy provided corrected data on ratcheted maximum demand. More information on why this data was updated is discussed in our capex assessment in appendix C of attachment 6.

### **B.3.4 Criticisms of our assessment approach**

Ergon Energy considered in its revised proposal that after comparing our rate of change and Ergon Energy's rate of change we adopted our own lower estimate.<sup>205</sup>

With the exception of 2015–16 where our rate of change was 0.08 per cent less than Ergon Energy's, our estimate of the rate of change for the remaining years is higher than Ergon Energy's. Overall, in percentage terms our rate of change estimate is higher than Ergon Energy's. It is therefore incorrect to say that our approach leads to a lower estimate.

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<sup>202</sup> Consumer challenge panel , *CCP2 panel submission AER preliminary 2015–20 revenue determinations Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 59.

<sup>203</sup> NER, clause 6.5.6(a).

<sup>204</sup> We note Ergon Energy's customer growth in 2013–14 and 2015–16 was 1.61 percent and 1.62 per cent respectively.

<sup>205</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 9.

Ergon Energy also did not understand why we did not adopt its forecast rate of change when both forecasts are so similar.<sup>206</sup>

We do not consider it is reasonable to adopt Ergon Energy's initial proposal rate of change because it was similar to our preliminary decision rate of change estimate.

We explained in the Guideline and the preliminary decision that we assess the rate of change in the context of Ergon Energy's proposed total forecast opex.<sup>207</sup> We explained that our approach is to compare the service provider's total forecast opex with an alternative estimate that we develop ourselves.<sup>208</sup> Part of our estimate accounts for our best estimate of the rate of change in efficient opex.<sup>209</sup> We must adopt the best methodology for estimating this change. We do not consider it is reasonable for us to adopt a different forecasting methodology for one component just because the forecast amounts are similar. For instance, if one of the variables in our methodology is updated then it could lead to a very different forecast. By using the same methodology, even if the outcomes are similar, avoids this potential issue. By adopting an efficient forecast of the rate of change, irrespective of how similar this number is to other methodologies will also ensure our estimate of total opex is consistent with the NER opex requirements.

The CCP considered our overall rate of change estimate for Ergon Energy was too high relative to Energex's proposed rate of change and our preliminary decision for SA Power Networks.<sup>210</sup> In particular the CCP considered our forecast labour price growth for Queensland utilities was too high relative to our forecast for South Australian utilities and labour price growth should be offset by productivity improvements.<sup>211</sup>

Energex's proposed rate of change is not necessarily applicable to Ergon Energy. The rate of change is a firm specific forecast which varies based on a firm's characteristics. In any case, we accepted Energex's total opex forecast after comparing it to our alternative opex forecast using a rate of change estimate (1.63 per cent per annum) that was similar to Ergon Energy's rate of change estimate (1.72 per cent per annum).

We adopted a different approach to forecasting labour in our Queensland and South Australian preliminary decisions. For SA Power Networks' preliminary decision we could not adopt our preferred approach of averaging consultant forecasts because SA Power Networks did not provide a comparable labour price forecast. In its revised proposal SA Power Networks provided forecasts from BIS Shrapnel and we have taken an average of DAE and BIS Shrapnel's forecasts. We have forecast average annual price growth of 0.27 per cent and 0.40 per cent for Queensland and South

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<sup>206</sup> Ergon Energy, *Submission to the AER on its preliminary determination operation expenditure*, 30 June 2015, p. 9.

<sup>207</sup> AER, *Preliminary decision attachment 7*, April 2015, p. 278.

<sup>208</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

<sup>209</sup> AER, *Preliminary decision attachment 7*, April 2015, p. 17.

<sup>210</sup> Consumer challenge panel, *CCP2 panel submission AER preliminary 2015–20 revenue determinations Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 54.

<sup>211</sup> Consumer challenge panel, *CCP2 panel submission AER preliminary 2015–20 revenue determinations Energex and Ergon Energy revised revenue proposals*, 3 September 2015, p. 56.

Australia respectively. We note that consultants' forecasts change and reflect the most up to date information available to them.

The CCP also considered that our forecast productivity of zero was too low compared to gas distribution, electricity transmission and Ergon Energy's proposal.<sup>212</sup>

Both gas distribution and electricity transmission sectors have experienced positive productivity over the 2006–13 period. During this same period Economic Insights economic benchmarking analysis found a 1.79<sup>213</sup> per cent per annum decline in electricity distribution technical change productivity.<sup>214</sup> We noted in our preliminary decision that we did not expect this decline in productivity to continue and we based our forecast of zero productivity growth on our expectations of growth in the short to medium term. Economic Insights also considered zero productivity growth was reasonable as energy use and maximum demand stabilise.<sup>215</sup>

Ergon Energy's productivity forecast was not supported with any evidence. Nor did Ergon Energy explain why it changed its estimate from one per cent forecast productivity growth to 0.75 per cent forecast productivity growth between its initial and revised proposals. As with any variable, we can only forecast productivity growth based on the evidence available to us. We consider, based on the evidence available to us, the best estimate of productivity growth in the electricity distribution industry is zero.

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<sup>212</sup> Consumer challenge panel , *CCP2 panel submission AER preliminary 2015–20 revenue determinations Energex and Ergon Energy revised revenue proposals*, 3 September 2015, pp. 60–61.

<sup>213</sup> Economic Insights, *Economic benchmarking assessing of operating expenditure for NSW and ACT electricity DNSPs*, 17 November 2014, p. 41

<sup>214</sup> Technical change is the underlying change in productivity that represents the shift in the efficient frontier.

<sup>215</sup> Economic Insights, *Economic benchmarking assessing of operating expenditure for NSW and ACT electricity DNSPs*, 17 November 2014, p. 57



## C Step changes

In assessing a service provider's forecast, we recognise that there may be changed circumstances in the forecast period that may impact on the service provider's expenditure requirements. We consider those changed circumstances as potential 'step changes'.

We typically allow step changes for changes to ongoing costs in the forecast period associated with new regulatory obligations and for efficient capex/opex trade-offs. Step changes may be positive or negative. We would not include a step change if the opex that would otherwise be incurred to reasonably reflect the opex criteria, is already covered in another part of the opex forecast, such as base opex or the rate of change.

This appendix sets out our consideration of step changes in determining our opex forecast for Ergon Energy for the 2015–20 regulatory control period.

### C.1 Final position

We have included a step change of \$26.3 million (\$2014–15) for the market transaction centre in our alternative opex forecast. We are not satisfied that adding step changes for the other cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.

### C.2 Preliminary position

In its initial proposal, Ergon Energy proposed:

- step changes for non-network ICT and non-network alternatives<sup>216</sup>
- non-ongoing adjustments, for remediation of contaminated land and regulatory reset costs<sup>217</sup>
- a category specific forecast for parametric insurance.<sup>218</sup>

Ergon Energy also allocated an increase in overhead expenditure to opex over the 2015–20 regulatory control period. We estimated the total revenue impact of the increase in overheads allocated to opex was \$26.3 million.

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<sup>216</sup> Ergon Energy, *Regulatory proposal, Attachment 06.01.01: Operating expenditure summary operating costs*, October 2014, p. 17.

<sup>217</sup> Ergon Energy, *Regulatory proposal, Attachment 06.01.01: Operating expenditure summary operating costs*, October 2014, p. 15.

<sup>218</sup> Ergon Energy, *Regulatory proposal, Attachment 06.01.01: Operating expenditure summary operating costs*, October 2014, p. 26. Ergon Energy referred to this category specific forecast as a bottom up adjustment. Ergon Energy included other bottom up adjustments that are not considered as step changes under our assessment approach. The bottom up adjustment for SPARQ non capital project costs and asset service fees are discussed in the forecasting method section of the opex attachment 7. The demand management innovation allowance is discussed in attachment 12 which discusses the demand management incentive scheme (DMIS). The TUOS charges for Chumvale and Powerlink are discussed in our pricing proposal section.

We assessed all of these adjustments as step changes. The total revenue impact of the proposed adjustments was \$171 million (\$2014–15).<sup>219</sup>

We did not include any step changes in our opex forecast in our preliminary decision. We were not satisfied that adding step changes for the cost drivers identified by Ergon Energy would have led to a forecast of opex that reasonably reflected the opex criteria.

The CCP considered our assessment process was sound. It agreed with our decisions that both Ergon Energy and Energex proposed step changes related to activities that we had explicitly considered in determining their efficient base level opex.<sup>220</sup>

### C.3 Ergon Energy’s revised proposal and submissions

In its revised proposal, Ergon Energy repropoed step changes for non-network ICT and parametric insurance and a category specific forecast for overheads. It proposed a new step change for a market transaction centre.

In its revised proposal, Ergon Energy forecast the cost of the step changes using a different opex base year to the one it used in its original proposal. In its initial proposal it used a 2012–13 base year. In its revised proposal it used a 2013–14 base year. The change of base year impacts the size of some of the proposed step changes and means the quantum of the forecasts are not directly comparable between the initial and revised proposals.

Ergon Energy's proposed step changes in its initial and revised proposal and our preliminary position are outlined in Table below.

**Table C.1 Ergon Energy's proposed step changes in its initial and revised proposals (\$ million, 2014–15) and our final decision**

Proposed step change	Initial proposal	AER preliminary decision amount	Revised proposal	Final decision
Non-network ICT	53.7 <sup>221</sup>	–	82.2 <sup>a</sup>	–
Non-network alternatives (demand management)	18.4	–	–	–
Parametric insurance	65.9 <sup>b</sup>	–	65.9 <sup>b</sup>	–
Remediation of contaminated land	6.3	–	–	–

<sup>219</sup> AER, *Ergon Energy Preliminary determination 2015–20, Attachment 7*, April 2015, p. 300.

<sup>220</sup> Consumer Challenge Panel (CCP2 Panel), *Submission AER Preliminary 2015-20 Revenue Determinations Energex and Ergon Energy Revised Revenue Proposals*, 3 September 2015, p. 62.

<sup>221</sup> We note non-network ICT is an overhead and only a portion of this is allocated to standard control opex. Ergon Energy did not identify the allocation of this step change to opex. This amount represents the total cost of the overhead rather than the opex for standard control services.

Proposed step change	Initial proposal	AER preliminary decision amount	Revised proposal	Final decision
Regulatory reset costs	6.3	–	–	–
Overheads allocated to opex <sup>222</sup>	26.3	–	–63.7 <sup>c</sup>	–
Market transaction centre (new)			26.3	26.3

Source: Ergon Energy, *Regulatory proposal*; Ergon Energy, *Revised regulatory proposal, 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs, p. 13*. AER estimates.

Note: (a) Ergon Energy forecast these costs using a different base year to the one it used in its original proposal, so the forecasts are not directly comparable. Only a portion of these non-network ICT cost is allocated to standard control services opex. The difference between the initial proposal and revised proposal is due to Ergon Energy incorporating the incremental cost of its category specific forecast in this step change. It was previously included in a separate part of its proposal.

(b) Ergon proposed \$65 million (\$2013–14). We adjusted to \$2014–15.

(c) Ergon Energy forecast total overhead costs using a different base year to the one it used in its original proposal, so the forecasts are not directly comparable. This is the amount the total opex forecast decreases because Ergon Energy applied a category specific forecasting approach to overheads.

We outline the assessment approach we have applied to assess Ergon Energy's proposed step changes below. We then consider each of the issues raised in Ergon Energy's revised proposal and in submissions.

## C.4 Assessment approach

Our assessment of proposed step changes must be understood in the context of our overall method of assessing total required opex using the "base step trend" approach. When assessing a service provider's proposed step changes, we consider whether they are needed for the total opex forecast to reasonably reflect the opex criteria.<sup>223</sup> Our assessment approach specified in the Guideline<sup>224</sup> and is more fully described in section 7.3 of this attachment.

As a starting point, we consider whether the proposed step changes in opex are already compensated through other elements of our opex forecast, such as base opex or the 'rate of change' component. Step changes should not double count costs included in other elements of the opex forecast.

We generally consider an efficient base level of opex (rolled forward each year with an appropriate rate of change) is sufficient for a prudent and efficient service provider to meet all existing regulatory obligations. This is the same regardless of whether we

<sup>222</sup> This is the increase in overheads attributable to the application of the cost allocation method rather than to the change in the level of total overheads. Total overheads are allocated between opex, capex and alternative control services. The increase is the result of changing the base year from 2012–13 to 2013–14.

<sup>223</sup> NER, clause 6.5.6(c).

<sup>224</sup> AER, *Expenditure assessment forecast guideline*, November 2013, pp.11, 24.

forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our opex forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex to reasonably reflect the opex criteria.

We forecast opex by applying an annual 'rate of change' to the base year for each year of the forecast regulatory control period. The annual rate of change accounts for efficient changes in opex over time. It incorporates adjustments for forecast changes in output, price and productivity. Therefore, when we assess the proposed step changes we need to ensure that the cost of the step change is not already accounted for in any of those three elements included in the annual rate of change. The following explains this principle in more detail.

For example, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures all changes in output then step changes that relate to forecast changes in output will not be required. To give another example, a step change is not required for the maintenance costs of additional office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year, which includes office maintenance) to account for forecast network growth.<sup>225</sup>

By applying the rate of change to the base year opex, we also adjust our opex forecast to account for real price increases. A step change should not double count price increases already compensated through this adjustment. Applying a step change for costs that are forecast to increase faster than CPI is likely to yield a biased forecast if we do not also apply a negative step change for costs that are increasing by less than CPI. A good example is insurance premiums. A step change is not required if insurance premiums are forecast to increase faster than CPI because within total opex there will be other items opex where the price may be forecast to increase by less than CPI. If we add a step change to account for higher insurance premiums we might provide a more accurate forecast for the insurance category in isolation; however, our forecast for opex as a whole will be too high.

Further, to assess whether step changes are captured in other elements of our opex forecast, we will assess the reasons for, and the efficient level of, the incremental costs (relative to that funded by base opex and the rate of change) that the service provider has proposed. In particular, we have regard to:<sup>226</sup>

- whether there is a change in circumstances that affects the level of expenditure a prudent service provider requires to meet the opex objectives efficiently

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<sup>225</sup> AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, p.73. See, for example, our decision in the Powerlink determination; AER, *Final decision: Powerlink transmission determination 2012–17*, April 2012, pp, 164-5.

<sup>226</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p.11.

- what options were considered to respond to the change in circumstances
- whether the option selected was the most efficient option—that is, whether the service provider took appropriate steps to minimise its expected cost of compliance
- the efficient costs associated with the step change and whether the proposal appropriately quantified all costs savings and benefits
- when this change event occurs and when it is efficient to incur expenditure, including whether it can be completed over the regulatory period
- whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.

One important consideration is whether each proposed step change is driven by an external obligation (such as new legislation or regulations) or an internal management decision (such as a decision to use contractors). Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control in order to be expenditure that reasonably reflects the opex criteria. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken. As noted above, the opex forecasting approach may capture these costs elsewhere.

Usually increases in costs are not required for discretionary changes in inputs.<sup>227</sup> Efficient discretionary changes in inputs (not required to increase output) should normally have a net negative impact on expenditure. For example, a service provider may choose to invest capex and opex in a new IT solution. The service provider should not be provided with an increase in its total opex to finance the new IT since the outlay should be at least offset by a reduction in other costs if it is efficient. This means we will not allow step changes for any short-term cost to a service provider of implementing efficiency improvements. We expect the service provider to bear such costs and thereby make efficient trade-offs between bearing these costs and achieving future efficiencies.

One situation where a step change to total opex may be required is when a service provider chooses an operating solution to replace a capital one.<sup>228</sup> For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa. In doing so we will assess whether the forecast opex over the life of the alternative capital solution is less than the capex in NPV terms.

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<sup>227</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 24.

<sup>228</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p. 24; AER, *Explanatory guide: Expenditure assessment forecast guideline*, November 2013, pp.51-52.

## C.4.1 Parametric insurance

Ergon Energy proposed an increase in opex of \$65.9 million (\$2014–15) to obtain parametric insurance to provide financial protection against the costs of cyclones and storms.<sup>229</sup>

Parametric insurance provides organisations with a predetermined payment contingent on an exogenous trigger event, or parameter, which generally needs to be validated by an independent third party. Parametric insurance does not operate like traditional insurance to indemnify organisations for the actual loss incurred. It operates to provide a specific payment intended to cover part or all of the loss incurred without the need to prove that assets were actually damaged.

We have not included a step change for parametric insurance in our total opex forecast. We are satisfied that our opex forecast already reasonably reflects the opex Ergon Energy needs to efficiently deliver standard control distribution services in the 2015–20 regulatory period. This is consistent with our preliminary decision.

### Ergon Energy's initial proposal and our preliminary position

Ergon Energy stated historically it has not insured its electricity network assets against such damage because of a lack of available and efficiently priced insurance cover in the market.<sup>230</sup> Typically, distribution network service providers are not able to, or do not deem it efficient to insure pole and wire assets, and therefore Ergon Energy is not unusual in this regard. As part of the determination process, a distributor is typically able to 'pass through' the costs of high cost uncontrollable events that are not built into its distribution determination.

Cyclones that have affected Ergon Energy have been Cyclone Larry in 2006, Cyclone Yasi in 2011 and Cyclone Marcia in 2015 which caused around \$43 million, \$100 million and \$32 million respectively in damage to assets.<sup>231</sup> Ergon Energy sought and received a cost pass through following Cyclone Larry.<sup>232</sup> It did not seek a pass through for Cyclones Yasi or Marcia. This meant it funded a significant part of the costs of these events from other sources. In other words, it self-insured these risks.<sup>233</sup>

In our preliminary decision, we did not include a step change for parametric insurance.<sup>234</sup> We sought advice from AM Actuaries about whether it considered the cost of the proposed parametric insurance was reasonable given the risks and possible

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<sup>229</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04: Step changes for operating costs*, July 2015, p. 3. Ergon Energy proposed \$65 (\$real, 2013-14).

<sup>230</sup> Ergon Energy, *Regulatory proposal, Parametric insurance*, 22 October 2014, p. 3.

<sup>231</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, p. 23.

<sup>232</sup> Queensland Competition Authority, *Annual report 2007–08*, 24 September 2009 p. 7.

<sup>233</sup> Additional capex as a result of these cyclones would be included in the RAB.

<sup>234</sup> AER, *Draft decision Ausgrid distribution determination 2015–19 - Attachment 7*, November 2014, pp. 238-239.

costs associated with storms and cyclones in Northern Queensland. AM Actuaries considered the cost of the proposed insurance did not appear reasonable.<sup>235</sup>

We agreed with AM Actuaries that:

- Ergon Energy had not sufficiently demonstrated it would be more efficient to buy parametric insurance than to retain the risk itself
- given the cost of the insurance, the expected payout and the size of Ergon Energy's asset base, Ergon Energy was appropriately placed financially to self-insure against cyclone and storm damage.

We received a submission from the Queensland Council of Social Services (QCOSS) which agreed with our preliminary decision.<sup>236</sup>

## Ergon Energy's revised proposal

In its revised proposal, Ergon Energy repropoed a step change of \$65.9 million for parametric insurance.<sup>237</sup> It also listed different parametric insurance options its insurance advisers considered but these options did not affect its revised proposal.<sup>238</sup> Ergon Energy's criticisms of our preliminary decision are addressed below.

## Reasons for our final position

While Ergon Energy provided a critique of our preliminary decision, it did not address the key concerns we raised in our preliminary decision. In particular it did not provide further evidence to show consumers would be better off paying for parametric insurance than if Ergon Energy continued with its current risk management approach. As such, we have not deviated from our preliminary decision in reaching our final decision.

In our assessment approach, in the Guideline<sup>239</sup> and in our preliminary decision<sup>240</sup> we state when we assess a step change we will have regard to:

- what options were considered
- whether the option selected was the most efficient option.

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<sup>235</sup> AM Actuaries, *Review of Ergon Energy's parametric insurance proposal*, 26 February 2015, p. 1 [Confidential].

<sup>236</sup> QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-20*, July 2015, pp. 19-20.

<sup>237</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04 Step changes for operating costs*, 3 July 2015, pp. 3-7; *Parametric insurance*, 3 July 2015. The different options involved reduced premiums for reduced payouts but the loss ratio did not change.

<sup>238</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, pp. 35-40. The options involved reduced premiums for reduced payouts, but the loss ratio remained unchanged.

<sup>239</sup> AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 15.

<sup>240</sup> AER, *Ergon Energy Preliminary determination 2015–20*, Attachment 7, p. 309.

Ergon Energy did not provide a cost benefit analysis of the parametric insurance to demonstrate it is the most efficient option to manage the risk of cyclone damage. In particular, it did not demonstrate that parametric insurance is more efficient than its current risk management approach which is to self-insure most of the risk of cyclone damage.

We also engaged AM Actuaries to review Ergon Energy's revised proposal.<sup>241</sup> After reviewing the material provided by Ergon Energy, AM Actuaries concluded that it did not contain any new or additional information that changed its view. AM Actuaries stated:

The proposed parametric insurance represents an additional charge to consumers with no material benefit to consumers. In my view, the proposed parametric insurance arrangements only superficially address the underlying risk management issues and Ergon have failed to adequately consider other risk financing strategies and their implications.<sup>242</sup>

AM Actuaries' conclusions informed our final position not to include a step change for parametric insurance. Our concerns with Ergon Energy's proposal are outlined below:

- By not seeking a cost pass-through for recent cyclones, including Yasi and Marcia, Ergon Energy's recent practice has been to essentially self-insure against cyclone damage. AM Actuaries stated:<sup>243</sup>

Self-insurance normally provides the lowest cost option. This is because Ergon can expect the long term cost of any insurance arrangement to exceed pay-outs...Insurers will always price products (target a loss ratio of around 50 per cent) to include the cost of access to "at risk" capital, expenses and profit.

If self-insurance normally provides the lowest cost option compared to commercial insurance, the onus is on Ergon Energy to show why it cannot continue to self-insure. It has not adequately demonstrated why it needs to change its practices.

- Although the level of cover of the proposed parametric insurance is higher than available under traditional insurance, Ergon Energy did not provide evidence that this level of cover could not be reasonably managed through self-insurance. AM Actuaries stated:<sup>244</sup>

This cost/benefit analysis depends on the capacity of an organisation to finance residual risk, which depends on the impact that potential losses would have on its balance sheet or its ability to fund the loss from normal operating profit.

Ergon Energy's financial ability to cover the cost of major storm damage was evidenced when it absorbed the costs of Cyclone Yasi in 2011. Ergon Energy

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<sup>241</sup> AM Actuaries, *Review of Ergon Energy's revised parametric insurance proposal*, September 2015.

<sup>242</sup> AM Actuaries, *Review of Ergon Energy's revised parametric insurance proposal*, September 2015, p. 1.

<sup>243</sup> AM Actuaries, *Review of Ergon Energy's revised parametric insurance proposal*, September 2015, p. 6.

<sup>244</sup> AM Actuaries, *Review of Ergon Energy's revised parametric insurance proposal*, September 2015, p. 6.



described Yasi as the largest storm system in 'living memory'.<sup>245</sup> It crossed the coast of Queensland as a category 5 cyclone with wind speeds of 295 km/h. It took out supplies to nearly a third of Ergon Energy's customer base and at least 50 major substations were off supply. Despite being such a large storm, Ergon Energy was able to finance the cost of the damage. It did this without applying for a cost pass through and was able to post after tax profits for standard control services of \$94 million (\$ nominal) in 2010–11 and \$53 million (\$ nominal) in 2011–12.<sup>246</sup>

- Despite requesting this information,<sup>247</sup> Ergon Energy did not produce evidence of its Board's risk appetite or risk tolerance, to support its risk management approach. AM Actuaries expected this as part of good governance.
- Ergon Energy stated the AEMC and the AER are unambiguous in requiring network service providers to manage risks if it is at all possible to do so.<sup>248</sup> We agree with this statement. However, Ergon Energy also stated wherever it is feasible to manage risks through the commercial insurance market, it should do this rather than transfer the risk to customers via a cost pass through.<sup>249</sup> We disagree with this statement. We do not consider commercial insurance is the only alternative to transferring the risk to customers via a cost pass through. When we say a service provider is required to manage its risks, we consider it should make the most efficient choice between commercial insurance, self-insurance and risk mitigation. For example, Ergon Energy decided it was more efficient to self-insure most of the risk of cyclone damage than to obtain traditional insurance. Just because we consider the parametric insurance is not cost effective, it does not follow that we consider Ergon Energy should rely on cost pass throughs. It could continue to self-insure rather than seek a cost pass through to manage these risks.
- Ergon Energy stated that, in the absence of parametric insurance, additional costs would be borne by consumers in the future via the cost pass through mechanism.<sup>250</sup> However, Ergon Energy does not appear to recognise that parametric insurance does not prevent the risk of cost pass-throughs. For instance if a major storm occurs, the payout may not fully cover the cost of the damage sustained because:

(a) the parametric insurance payout and the losses incurred are not directly related

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<sup>245</sup> Ergon Energy, *Revised regulatory proposal*, July 2015, p. 81.

<sup>246</sup> Ergon Energy, *Regulatory accounts*, Income statements for 2010–11 and 2011–12.

<sup>247</sup> AER, Reset RIN, Schedule one, Question 11.1(a). Ergon Energy provided a lot of detail about its risk management policy but it did not provide "details of the level of risk its board is willing to accept including the nature and level of risks and the level of loss that can be sustained".

<sup>248</sup> Ergon Energy, *Revised regulatory proposal*, *Supporting document 06.01.04 - Revised step changes*, 3 July 2015, p. 5.

<sup>249</sup> Ergon Energy, *Revised regulatory proposal*, *Supporting document 06.01.04 - Revised step changes*, 3 July 2015, p. 5.

<sup>250</sup> Ergon Energy, *Revised regulatory proposal*, *Supporting document 06.01.04 - Revised step changes*, 3 July 2015, p. 5.

(b) the parametric insurance sets a maximum payment over five years but if there is more than one cyclone in the period this may not cover the costs.

In these cases, even though consumers would have paid for the insurance, Ergon Energy might still be eligible to apply for a cost pass through.

- Ergon Energy considered we must start from the assumption that the quotes provided by the insurance market reflect the prudent and efficient cost of managing these risks.<sup>251</sup> We acknowledge the prices quoted from Endurance Re and Swiss Re likely represents reasonable estimates of the efficient cost of underwriting the risk. However, we disagree that just because the price of a product or service reflects efficient pricing, it necessarily represents an efficient solution or cost of providing network services. Ergon Energy must compare the cost of its proposed option against the cost of other possible options to demonstrate it is prudent and efficient.
- Ergon Energy stated obtaining parametric insurance would improve its regulatory compliance and remove its capital funding risk.<sup>252</sup> We are not persuaded that the insurance would materially affect Ergon Energy's regulatory compliance or capital funding risk. Ergon Energy did not provide evidence to show how its retention of cyclone risk in recent years had negatively impacted its compliance obligations. Further, we consider there is likely to be no or little capital funding risk. We agree with QCOSS which submitted 'it is open to Ergon to apply for cost pass throughs associated with cyclone damage above a cost threshold, which provides a significant measure of financial protection for Ergon against major cyclone damage.'<sup>253</sup>
- Ergon Energy stated the cost of the insurance is reasonable, particularly when the results of back testing are taken into account.<sup>254</sup> It stated over the period 1956 to 2011, if it had parametric insurance, the net payments made by Ergon Energy would have only been around \$c-i-c million more than the net payments required to be made by the insurer.<sup>255</sup> However, the result depends on the choice of period used. If we chose a different period, for example, a period that starts a year later and finishes a year earlier (1957 to 2010), Ergon Energy would have paid around three times that amount.<sup>256</sup> We therefore do not consider this analysis helps in demonstrating that purchasing parametric insurance would be prudent or efficient.
- Ergon Energy stated that in a customer survey, two thirds of respondents said they would be prepared to see a small amount added to their bill to cover insurance rather than see the cost of severe weather events passed on when they occur.<sup>257</sup>

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<sup>251</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, p. 20.

<sup>252</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, p. 42.

<sup>253</sup> QCOSS, *Response to Australian Energy Regulator Preliminary Decision for Queensland distributors 2015-20*, July 2015, pp. 19-20.

<sup>254</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, pp. 33-34.

<sup>255</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance (confidential version)*, 3 July 2015, p. 34.

<sup>256</sup> AER analysis.

<sup>257</sup> Ergon Energy, *Revised regulatory proposal, Parametric insurance*, 3 July 2015, p. 34.

We do not consider the survey question demonstrated consumers' willingness to pay for a possible increase in price stability. This is because it did not inform customers how much would be added to their bill or how much the likely cost pass through would be per household.

## C.4.2 Market transaction centre

In its revised proposal, Ergon Energy introduced a new step change of \$26.3 million (\$2014–15) for a market transaction centre.<sup>258</sup> Because the driver of the step change is a regulatory change, we have included it in Ergon Energy's total opex forecast.

Under the Electricity Distribution Network Code (EDNC),<sup>259</sup> Ergon Energy has been allowed to operate under a less onerous arrangement in comparison to other distributors when processing information requests from retailers. This arrangement is referred to as the minimalist transitioning approach (MTA). The MTA applies to the provision of customer National Metering Identifiers (NMI) information and the creation of NMI for contestable customers in its distribution region.

Each year, the Queensland Competition Authority (QCA) has been required to review whether the MTA should remain in place. On 30 July 2015, the QCA decided that, from 30 July 2016, the MTA should no longer apply to Ergon Energy. The QCA revoked the MTA because Ergon Energy informed it that it was ready to meet full market publication requirements.

Under the MTA, Ergon Energy has been allowed to operate a manual enquiry system rather than an automated enquiry system which interfaces with AEMOs Market Settlement and Transfer Solution (MSATS) system. The MTA applied because there was little prospect of retail competition in regional Queensland to justify the expense of an automated system. Ergon Energy stated it will achieve full market publication requirements by paying Energex a service fee to deliver these services on Ergon Energy's behalf. The market transaction processing services will be delivered via a joint Market Transaction Centre managed by Energex.

We consider it is more efficient for Ergon Energy to pay Energex to provide these services rather than invest in its own automated system. Ergon Energy stated the move to a joint MTC provides a cost saving compared to developing the capability within Ergon Energy.<sup>260</sup>

A service agreement has been signed by the respective CEOs of Ergon Energy and Energex. This agreement states the commercial terms of the provision of the services by Energex. The costs in the service agreement are based on Energex's costs to

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<sup>258</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04, Step changes for operating costs*, July 2015, pp. 3,8-10. Ergon Energy proposed \$26 million (\$ real, 2013-14).

<sup>259</sup> Electricity Distribution Network Code, clause 4.4; The Electricity Distribution Network Code replaced the Electricity Industry Code on 1 July 2015.

<sup>260</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.02.11, Step change summary - Market Transaction Processing Capability*, July 2015, p. 2.

comply with the EDNC adjusted for Ergon Energy's different resourcing requirements, such as number of NMIs and transaction levels. We received further information from Ergon Energy that set out the tasks that will be undertaken as part of the arrangement and the estimated resources allocated to each task.<sup>261</sup>

Having reviewed this material, we consider:

- the transaction tasks in the agreement appear consistent with our understanding of what Ergon is required to do to comply with the EDNC
- the cost estimates are reasonable.

### C.4.3 Overhead costs allocated to opex

Ergon Energy used a different approach to forecast overheads allocated to opex to our preferred approach which is to forecast total opex including overheads. Ergon Energy used a base step trend method to forecast total overheads separately. It then allocated overheads between opex, capex and non-standard control services according to its cost allocation method (CAM). This method is a category specific forecast of overheads for the forecast period rather than relying on the revealed costs in the base year.<sup>262</sup> The overall impact of Ergon Energy's forecasting approach to overheads in its revised proposal is to decrease its total opex forecast by \$63.7 million.

In our final decision we maintain our position to forecast total opex and not include a category specific forecast for overheads allocated to opex.

In our preliminary decision, we reviewed Ergon Energy's forecasting method to identify if and where Ergon Energy's forecasting method departed from the method set out in the Guideline (the guideline forecasting method). Having considered the differences between the guideline forecasting method and Ergon Energy's method, we were satisfied that the guideline forecasting method produced an opex forecast that reasonably reflects the opex criteria. We did not use category specific forecasting methods to separately forecast any of Ergon Energy's opex categories other than debt raising costs in our substitute total opex forecast.<sup>263</sup>

In its revised proposal, Ergon Energy maintained its category specific forecasting approach to overheads. It separately forecast total overheads and then allocated them between regulated services and unregulated services; standard control services and alternative control services; opex and capex. It allocated the total overhead forecast according to its approved CAM. It stated aggregate standard control service base year costs cannot be trended in a linear manner. This is because the overhead portion of

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<sup>261</sup> Ergon Energy, *Response to AER information request 085*, August 2015.

<sup>262</sup> Because Ergon Energy's forecast for overheads allocated to opex is higher than actual overheads allocated to opex in 2012–13, we can consider it as either a step change or a category specific forecast.

<sup>263</sup> AER, *Ergon Energy Preliminary determination 2015–20, Attachment 7 Opex*, April 2015, pp. 23–24.

the standard control service base year will vary, even if the overhead cost item itself trends in a linear manner.<sup>264</sup>

We are not satisfied including a category specific forecast for overheads would lead to a forecast of opex that reasonably reflects the opex criteria.

We are required to assess whether total opex is consistent with the opex criteria. Within total opex which is relatively stable, we expect to see variation in the composition of expenditure from year to year. That is, expenditure for some categories will be higher than usual in a given year while other categories will be lower than usual.

As discussed in our forecasting approach in the preliminary decision,<sup>265</sup> using category specific forecasting methods for some opex categories may produce better forecasts of expenditure for those categories but this may not produce a better forecast of total opex. Generally it is best to use the same forecasting method for all cost categories of opex because hybrid forecasting methods (that is, combining revealed cost and category specific methods) can produce biased opex forecasts inconsistent with the opex criteria.

In general, total opex is relatively recurrent. Therefore, we would expect to forecast a similar amount of opex regardless of which base year we use. However, if we were to include a category specific forecast for overheads, all else being equal, it would result in a very different total opex forecast, depending on whether the opex base year was 2012–13 or 2013–14. For instance, Table shows that total opex less overheads was \$30 million lower in 2013–14 than in 2012–13. This suggests that using a base year of 2013–14 would lead to a materially lower opex forecast than a 2012–13 base year. This is despite total opex for the two years being similar. We see no reason why this should be the case.

**Table C.2 Ergon Energy, recent total opex and overheads allocated to opex (\$2014–15)**

	2012-13	2013-14
Total opex	362	361
Overheads allocated to opex	89	118
Total opex less reported overheads	273	243

Note: Excludes FIT, debt raising costs and movement in provisions.

<sup>264</sup> Ergon Energy, *Revised regulatory proposal, Document 06, Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015, p. 86.

<sup>265</sup> AER, *Ergon Energy preliminary determination 2015–20, Attachment 7, Forecasting approach appendix D*, p. 313.

In its revised proposal, Ergon Energy stated that we have set aside the CAM in favour of the expenditure assessment guideline and that this is not allowed under the NER 6.5.6(b)(2) or under its CAM.<sup>266</sup>

We agree that under the NER, Ergon Energy needs to forecast expenditure that is properly allocated to standard control services in accordance with the CAM. However, under the NER, we are not constrained by the CAM in the forecasting approach we adopt. The guideline forecasting method is not intended to be aligned to the CAM.

#### C.4.4 Non-network ICT (overheads)

Consistent with our preliminary decision, we have not included a step change in our total opex forecast for an increase in non-network ICT expenditure.

Ergon Energy initially proposed increases in its non-network ICT expenditure through a category specific forecast<sup>267</sup> and a step change.<sup>268</sup> In our preliminary decision we considered category specific forecasts could result in a biased forecast. This is because service providers may only include costs that are increasing more rapidly relative to other opex categories without also forecasting opex items that increase less rapidly.<sup>269</sup>

We also considered non-network ICT was a business as usual cost that an efficient service provider would already incur. For this reason we did not include the step change portion of Ergon Energy's non-network ICT proposal in our alternative opex forecast.<sup>270</sup>

Ergon Energy indicated in its revised proposal that non-network ICT costs are a driver of its opex forecast. However Ergon Energy has not sufficiently explained how its proposed step change for non-network ICT expenditure contributes to its opex forecast.<sup>271</sup> For instance, we understand that Ergon Energy treats non-network ICT expenditure as an overhead and a proportion of this is allocated to standard control services (SCS) opex.<sup>272</sup> However, it is not clear from Ergon Energy's proposal and response to information requests how much of its increase in non-network ICT overheads it allocates to SCS opex, are the drivers of this increase.

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<sup>266</sup> Ergon Energy, *Revised regulatory proposal, Document 06, Appendix A: Operating expenditure forecasts for Standard Control Services*, July 2015, p. 87.

<sup>267</sup> Ergon Energy, *Revised regulatory proposal, Appendix A: operating expenditure forecasts for Standard Control Services*, p. 79.

<sup>268</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04: Step changes for operating costs*, 31 October 2014, p. 3.

<sup>269</sup> AER, *Ergon Energy preliminary determination 2015–20, Attachment 7*, pp.314–315.

<sup>270</sup> AER, *Ergon Energy preliminary determination 2015–20, Attachment 7*, p. 304.

<sup>271</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.01 forecast expenditure summary – operating costs*, p. 13. This is because the amount reported relates to total overheads rather than the portion allocated to SCS opex.

<sup>272</sup> Ergon Energy, *Submission to revised proposal*. p. 14.

For instance, Ergon Energy identified the following non-network ICT projects that were not undertaken by Ergon Energy in its 2013–14 base year:

- Contact Centre Technology (CCT)
- Field Force Automation (FFA)
- Market Systems also referred to as network customer information system.<sup>273</sup>

Ergon Energy has provided businesses cases for each of these projects. However, rather than reporting the cost increases from these projects directly, Ergon Energy reported costs in two broad categories:

1. The asset service fee (ASF)<sup>274</sup> which represents the capex associated with the new projects listed above and other capex costs for existing ICT capex projects. These costs are expensed into non-network ICT overheads.
2. Operational support<sup>275</sup> which represents the opex associated with the projects listed above.

This is an issue because the proposal does not show how the costs reported in the new ICT business cases reconciles with the two non-network ICT step change categories.

We have endeavoured to gather the additional information to understand Ergon Energy's proposal and how it contributes to its forecast. Table shows the material we have reviewed in our final decision.

**Table C.3 Non-network ICT materials reviewed**

Revised proposal	Revised proposal (business cases)	Information request response
07.00.07 – (Revised) ICT expenditure forecast summary	MTA business case	Response to information request 85, dated 14 August 2015
Capitalised overheads and ICT expenditure – Response	Contact Centre Technology business case	Response to information request 85, dated 21 August 2015
KPMG – SPARQ ICT expenditure forecasts	Field Force Automation business case	Response to information request 85, dated 27 August 2015
06.01.01– (Revised) forecast expenditure summary – operating costs		Response to information request 85, dated 31 August 2015
06.01.04 – (Revised) step changes for operating costs		

<sup>273</sup> Ergon Energy, *Response to information request 085*, 21 August 2015, p. 2. And Ergon Energy, *06.01.04 (revised) step changes*, p. 13.

<sup>274</sup> Ergon Energy outsources its capex for non-network ICT to SPARQ solutions. SPARQ solutions then charges an asset service fee to Ergon Energy to recover the costs of depreciation and amortisation. Ergon Energy then allocates its ASF to overheads.

<sup>275</sup> Ergon Energy also calls this expenditure associated operating expenditure or operation and licence fee increases.

We have a number of concerns with the consistency of the information provided. For instance:

- In Ergon Energy's revised proposal it listed the ICT projects that drive its non-network ICT overheads but only reported the increase in overheads as a single category.<sup>276</sup> It did not provide a breakdown of how these ICT projects actually contribute to the increase in overheads. Further, the business cases for CCT and Market Systems only includes total opex costs for the life of the projects.<sup>277</sup> Therefore the cost benefit analysis provided in the business cases does not match the proposed step change amounts. It is not possible to disaggregate these total opex costs into the annual amounts reported in non-network ICT overheads. As Ergon Energy has not linked the cost benefit analysis to the actual increases in its forecast expenditure, we are not confident that the costs in its business cases are the same as the forecast overhead increases.
- Despite requesting this information, Ergon Energy was unable to provide a breakdown of costs in a Microsoft Excel Workbook. It only provided a written response that listed cost increases without supporting evidence.<sup>278</sup> We cannot assess the reasonableness of a cost estimate if a service provider does not provide a breakdown of the assumptions used to estimate the costs.
- Ergon Energy provided cost estimates in information request responses that did not reconcile with its business cases. For instance. Ergon Energy identified application support costs of \$1.5 million and \$1 million for Market Systems and FFA respectively.<sup>279</sup> However, there is no reference to these costs in the respective business cases.
- Ergon Energy did not quantify the impact of this step change on SCS opex. If a service provider does not quantify a step change it is difficult to assess its impact on SCS opex. We also note the reset RIN required Ergon Energy to provide justification for how the increase is expected to affect the relevant opex category and total opex.<sup>280</sup>

Nevertheless, even without this information, we have a number of other concerns with its proposal. It is due to the concerns set out below that we do not consider a step change for non-network ICT expenditure is required in our forecast of total opex.

1. The primary objective of Ergon Energy's ICT projects appears to be efficiency improvements. For example:

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<sup>276</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04.*

<sup>277</sup> Ergon Energy, *6039JZ – Contact centre technology*, 27 November 2013, p. 6 and Ergon Energy, *FACOM replacement and full retail contestability (FRC) capability*, 12 May 2014, p. 6.

<sup>278</sup> Ergon Energy, *Response to information request 085*, 21 August 2015.

<sup>279</sup> Ergon Energy, *Response to information request 085*, 21 August 2015, p. 1.

<sup>280</sup> AER, *Regulatory Information Notice issues under Division 4 of Part 3 of the National Electricity (South Australia) Law (Qld)*, 25 August 2014, p. 7.



- (a) Ergon Energy's business case for Contact Centre Technology stated the following

[t]his aging technology set results in inefficiencies by driving high process complexity, hierarchical decision making and cost.

Energex also has technology due for renewal, and this presents an opportunity for Ergon Energy and Energex to approach the market jointly for contact centre technologies, **reducing the costs associated with this process**. In addition, the resulting increased purchasing power will allow optimal establishment costs, and **reduced ongoing operational costs**, and allow Ergon Energy to reduce, modernise and rationalise the number of systems required to deliver customer outcomes.<sup>281</sup>

- (b) For Field Force Automation (FFA), Ergon Energy stated there would be 'field based FTE savings, dispatch savings and outage time reductions for a total net benefit of \$31.25 million in NPV terms.'<sup>282</sup>
- (c) For Ergon Energy's Market System project, its business case noted that the primary objective of the investment is customer service and support productivity/efficiency.<sup>283</sup>

We expect this should reduce Ergon Energy's opex over the 2015–20 regulatory control period. We noted in the Guideline that we would not allow step changes for any short-term cost to the distributors of implementing efficiency improvements in expectation of being rewarded through expenditure incentive mechanisms such as the EBSS.<sup>284</sup>

2. Ergon Energy's proposal represents a category specific forecast. We do not agree with this forecasting approach. As stated in our preliminary decision, and our assessment of overheads above, we do not forecast at the category level.<sup>285</sup> As noted above in our assessment of Ergon Energy's allocation of overheads step change we forecast at the total opex level using a consistent approach for all cost categories. Within total opex which is relatively stable, we would expect to see some variation in the composition of expenditure from year to year. That is, expenditure for some categories will be higher than usual in a given year while other categories will be lower than usual. Ergon Energy did not respond to this argument in its revised proposal.
3. Ergon Energy identified two new regulatory obligations in its revised proposal relating to operating in a fully contestable market place and the National Energy Customer Framework (NECF). In response to an information request, it could not identify how these were accounted for in its regulatory proposal.<sup>286</sup> For instance

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<sup>281</sup> Ergon Energy, *06.02.09 6039JA – contact centre technology business case*, 27 November 2013, p. 1.

<sup>282</sup> Ergon Energy, *Field Force Automation Phase 1, Gate 3 Business Case summary paper*, 19 December 2013, p.42.

<sup>283</sup> Ergon Energy, *FACOM replacement and full retail contestability capability*, 12 May 2014, p. 1.

<sup>284</sup> AER, *Expenditure forecast assessment guidelines for electricity distribution*, November 2013, p. 16.

<sup>285</sup> AER, *Ergon Energy Preliminary determination 2015–20, Attachment 7*, p. 315.

<sup>286</sup> Ergon Energy, *Revised regulatory proposal, Attachment 06.01.04*, pp. 13–14.

Ergon Energy noted that the removal of MTA costs was included in its MTC breakdown. It could not identify any specific additional costs associated with the NECF.<sup>287</sup>

4. We consider a project that increases both opex and capex is not an efficient trade-off. Ergon Energy considered its ICT expenditure to be a capex/opex trade off. It states this expenditure represents a substitution between capex and opex and we should be indifferent to the accounting treatment of costs and we have been inconsistent with our preliminary decision because we did not assess this step change as a capex/opex trade-off.<sup>288</sup> In our preliminary decision we stated that opex/capex trade-offs require an operating solution to replace a capital one. For example, a service provider may choose to lease vehicles when it previously purchased them.<sup>289</sup> Different accounting treatment of costs is not an opex/capex trade-off. We also note that Ergon Energy has forecast both opex and capex to increase as a result of its new ICT projects even though the main objective of its non-network ICT projects is efficiency improvements.

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<sup>287</sup> Ergon Energy, *Response to information request 085*, 31 August 2015, p. 1.

<sup>288</sup> Ergon Energy, *sub10.02 Ergon Energy – opex (general) response*, p. 15.

<sup>289</sup> AER, *Ergon Energy Preliminary determination 2015–20, Attachment 7*, p. 300.