



**FINAL DECISION**  
**Powercor distribution**  
**determination**  
**2016 to 2020**

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

May 2016

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## Note

This attachment forms part of the AER's final decision on Powercor's distribution determination for 2016–20. It should be read with all 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

Attachment 14 – Control mechanisms

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – f-factor scheme

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## Shortened forms

Shortened form	Extended form
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
augex	augmentation expenditure
CAM	cost allocation method
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
MFP	multifactor productivity
MPFP	multilateral partial factor productivity
MRP	market risk premium
MTFP	multilateral total factor productivity
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider

Shortened form	Extended form
opex	operating expenditure
PFP	partial factor productivity
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
VBRC	Victorian Bushfire Royal Commission
WACC	weighted average cost of capital

## 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 is 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 Powercor's forecast opex reasonably reflects the opex criteria.<sup>1</sup> We therefore do not accept the forecast opex Powercor included in its building block proposal.<sup>2</sup> We compare our substitute estimate of Powercor's opex for the 2016–20 regulatory control period with its initial regulatory proposal, our preliminary decision and Powercor's revised regulatory proposal in Table 7.1.<sup>3</sup>

**Table 7.1 Our final decision on total opex (\$ million, 2015)**

	2016	2017	2018	2019	2020	Total
Powercor's initial proposal	243.0	250.9	262.6	271.4	280.3	1308.2
AER preliminary decision	221.4	225.2	230.9	236.0	241.6	1155.1
Powercor's revised proposal	233.1	240.1	249.1	256.1	264.7	1243.0
AER final decision	225.5	229.3	236.6	241.6	248.0	1181.1

Source: AER analysis.

Note: Excludes debt raising costs.

Figure 7.1 shows our final and preliminary decision compared to Powercor's past actual opex, previous regulatory decisions and its initial and revised proposals.

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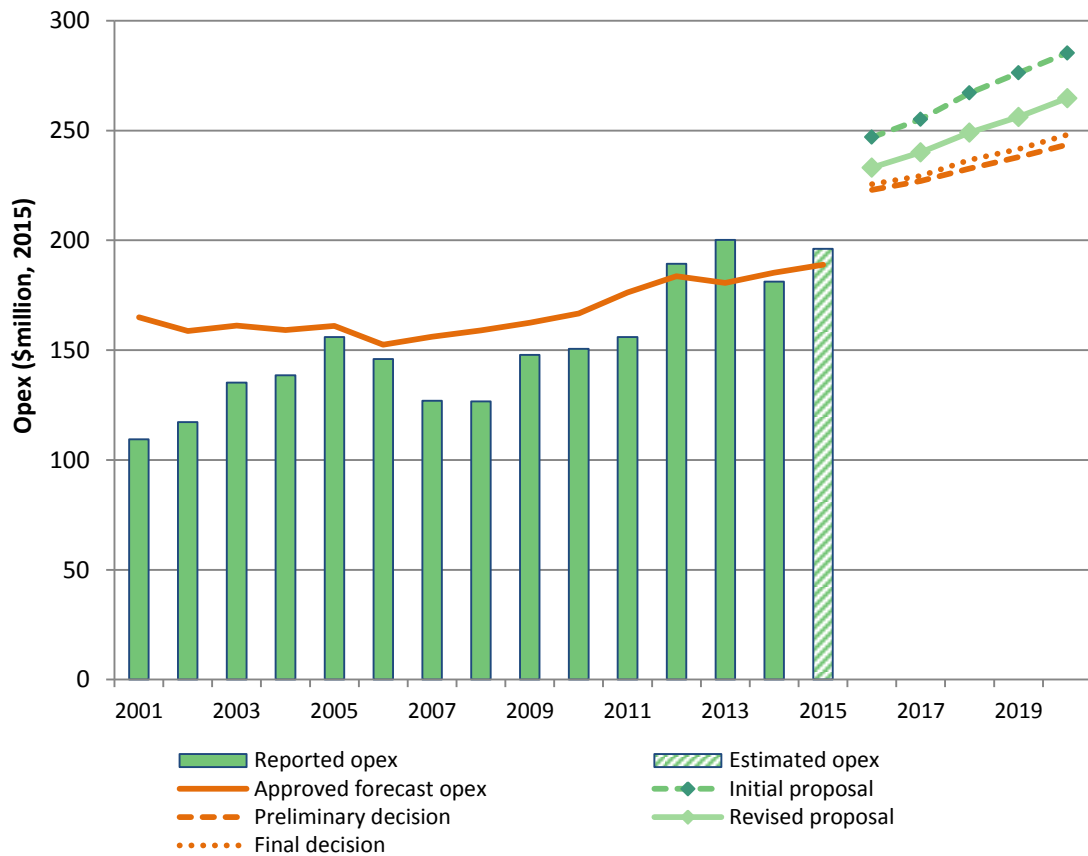
<sup>1</sup> NER, cl. 6.5.6(c).

<sup>2</sup> NER, cl. 6.5.6(d).

<sup>3</sup> NER, cl. 6.12.1(4)(ii).



**Figure 7.1 AER final decision compared to Powercor's past and proposed opex (\$ million, 2015)**



Source: AER analysis

Note: Includes debt raising costs

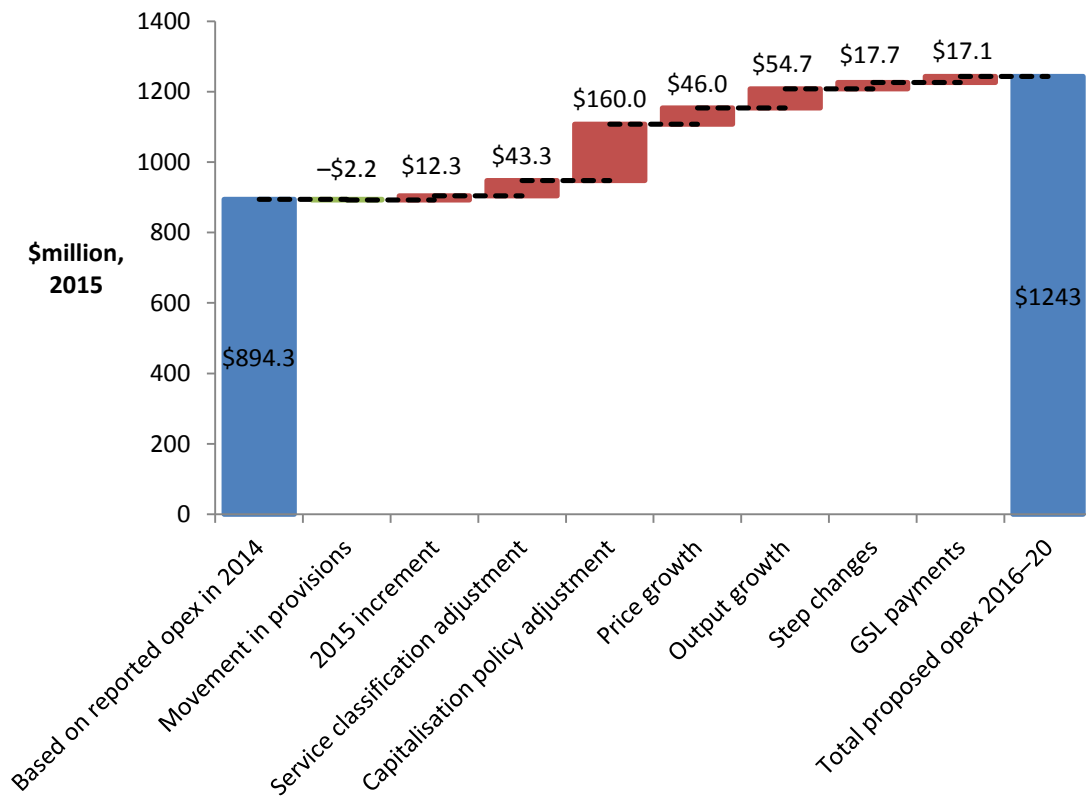
We note the main reason we and Powercor expect opex to increase in the 2016 to 2020 regulatory control period is because of changes in the way Powercor allocates its costs. For instance, from 2016 Powercor will expense all corporate overheads, whereas previously it partially capitalised these costs.

## 7.2 Powercor's revised proposal and submissions

In its revised proposal, Powercor proposed a forecast opex of \$1243.0 million (\$2015) for the 2016–20 regulatory control period. This is a 4.98 per cent decrease from the \$1308.3 million (\$2015) it initially proposed.

In Figure 7.2 we separate Powercor's forecast opex into the different elements that make up its forecast.

**Figure 7.2 Powercor's revised opex forecast (\$ million, 2015)**



Source: AER analysis

We describe each of these elements below:

- Powercor used the actual opex it incurred in 2014 as the base for forecasting its opex for the 2016–20 regulatory control period. This results in a base opex of \$894.3 million (\$2015) over the 2016–20 regulatory control period. This is \$3.7 million (\$2015) higher than our preliminary decision.
- Powercor's 2014 regulatory accounts include one-off accounting adjustments relating to provision changes. It adjusted base opex to remove the movement in provisions in 2014. The effect of this is to set the net forecast expenditure in this cost category to zero. This reduced Powercor's forecast by \$2.2 million (\$2015). This is consistent with our preliminary decision.
- Powercor adjusted its base opex to reflect the revised overhead capitalisation policy in its new cost allocation method. This increased Powercor's forecast by \$160.0 million (\$2015). This is consistent with our preliminary decision.
- Powercor also adjusted its base opex to add opex that is classified as standard control services in the 2016–20 regulatory control period. This increased Powercor's forecast by \$43.3 million (\$2015). This is \$24.9 million (\$2015) higher than our preliminary decision. This reflects different approaches to the allocation of AMI costs. In our preliminary decision we allocated these costs to alternative control services metering.

- To forecast the increase in opex between 2014 and 2015 Powercor added the difference between its opex allowances for 2014 and 2015. This is consistent with the approach set out in the *Expenditure Forecast Assessment Guideline* (the Guideline). This increased Powercor's forecast by \$12.3 million (\$2015). This is consistent with our preliminary decision.
- Powercor's proposed output growth using our approach to forecasting output growth. However, Powercor adopted a higher growth rate for its ratcheted maximum demand forecast. Output growth increased Powercor's opex forecast by \$54.7 million (\$2015). This is \$10.5 million (\$2015) higher than the output growth in our preliminary decision.
- Powercor proposed price growth for labour and materials price increases. Price growth increased Powercor's opex forecast by \$46.0 million (\$2015). This is \$28.2 million (\$2015) higher than the price growth in our preliminary decision.
- Powercor identified step changes in costs it forecast to incur during the forecast period, which were not incurred in 2014. This increased Powercor's forecast by \$17.7 million (\$2015). This is \$14.6 million (\$2015) higher than the step changes in our preliminary decision.
- Powercor included a category specific forecast for guaranteed service level (GSL) payments. This increased its forecast by \$17.1 million (\$2015). This is \$6.1 million (\$2015) higher than the GSL payments we forecast in our preliminary decision. The increase in GSL payments reflects new Electricity Distribution Code (EDC) requirements and a different forecasting approach to our preliminary decision.

### 7.3 Assessment approach

This section sets out our general approach to assessment.<sup>4</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 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>5</sup> If we are satisfied, we accept the service provider's forecast.<sup>6</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>7</sup> We only undertake the second task if we do not accept the service provider's forecast after undertaking the first task.

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<sup>4</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>5</sup> NER, cl. 6.5.6(c), 6.12.1(4).

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

<sup>7</sup> NER, cl. 6.5.6(d), 6.12.1(4)(ii).

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>8</sup>

The opex criteria that we must be satisfied a total forecast opex reasonably reflects are:<sup>9</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.

The AEMC noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.<sup>10</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>11</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. When assessing a proposed forecast, we recognise that efficient

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<sup>8</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

<sup>9</sup> NER, cl. 6.5.6(c).

<sup>10</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113.

<sup>11</sup> NER, cl. 6.5.6(a).

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>12</sup> We attach different weight to different factors. This approach has been summarised by the AEMC as follows:<sup>13</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.

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)

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<sup>12</sup> NER, cl. 6.5.6(c) and (d).

<sup>13</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 115.

- 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.

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>14</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>15</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>16</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>17</sup> The Guideline sets out our intended approach to assessing opex in accordance with the NER.<sup>18</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>19</sup> For the most part, we have not departed from the approach set out in the Guideline in this final decision.<sup>20</sup> In our framework and approach paper, we

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<sup>14</sup> NEL, ss. 7A and 16(2).

<sup>15</sup> NEL, s. 7A(2).

<sup>16</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>17</sup> AER, *Expenditure forecast assessment guideline - explanatory statement*, November 2013.

<sup>18</sup> NER, cl. 6.5.6.

<sup>19</sup> NER, cl. 6.2.8(c).

<sup>20</sup> We did not apply the DEA benchmarking technique. We outlined the reasons why we did not apply this technique in appendix A of our all NSW distribution determinations for the 2015–20 regulatory control period.

set out our intention to apply the Guideline approach in making this determination.<sup>21</sup> There are several parts of our assessment:

- We develop an alternative estimate to assess a service provider's proposal at the total opex level.<sup>22</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.
- 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.
- We assess the service provider's proposed base 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. The AEMC expressly endorsed this approach in its decision on the major rule changes that were introduced in November 2012. The AEMC stated:<sup>23</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 NSPs 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>21</sup> AER, *Stage 2 Framework and approach—NSW electricity distribution network service providers*, January 2014, p. 50.

<sup>22</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 7.

<sup>23</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:

- the efficiency criterion and the prudence criterion in the NER are complementary
- 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 a number of Australian regulators have employed 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>24</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 obligations to deliver services safely and reliably balance the financial incentives a service provider faces to reduce its costs. In general, this gives us confidence that recent historical opex will be at least enough to achieve the opex objectives.

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<sup>24</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

In choosing a base year, we need to make a decision whether to remove any categories of opex incurred in that year. 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.
- 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 we should assess these categories of opex 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). We designed the EBSS 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 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 opex*

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>25</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>26</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.

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<sup>25</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 22.

<sup>26</sup> AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 97.

By benchmarking a service provider's expenditure we can compare its productivity over time, and to other service providers. In our preliminary decision we used multilateral total factor productivity, partial factor productivity measures and several opex cost function models.<sup>27</sup>

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 we apply 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 non-labour) 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 opex and the rate of change in opex of an efficient service provider do not already include the proposed cost.<sup>28</sup>

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<sup>27</sup> We discuss the benchmarking models in detail in appendix A.

<sup>28</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

### *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.

### **7.3.1 Interrelationships**

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

- the operation of the EBSS in the 2010–15 regulatory control period, which provided Powercor an incentive to reduce opex in the 2014 base year
- 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 inter-relationship between capex and opex, for example, in considering Powercor's proposed step change for its mobile devices costs
- 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
- concerns of electricity consumers identified in the course of Powercor's engagement with consumers.

### **7.4 Reasons for final decision**

Generally, we agree with Powercor on the approach to forecasting total opex. However, due to some differences with forecasts of the inputs used we are not satisfied Powercor's proposed total forecast opex of \$1243.0 million (\$2015) reasonably reflects the opex criteria. We must not, therefore, accept Powercor's proposed total forecast opex.<sup>29</sup> As discussed above, we have used our alternative estimate of \$1181.1 million (\$2015) as our substitute estimate.<sup>30</sup>

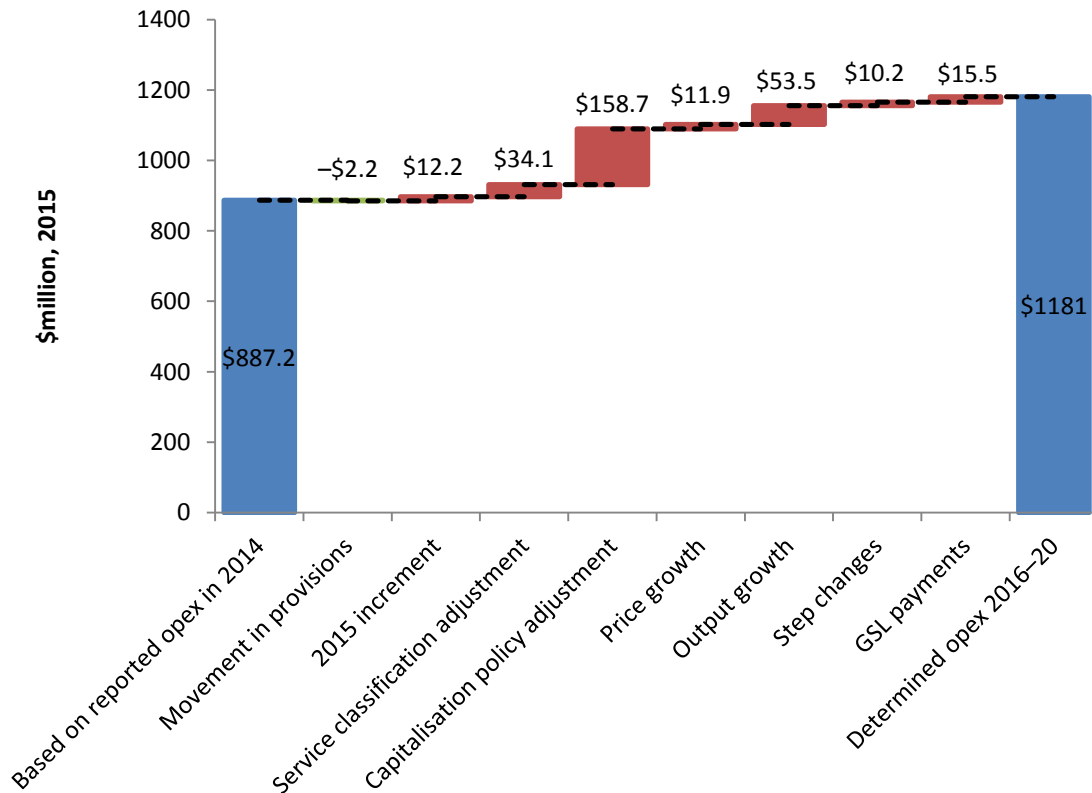
Figure 7.4 illustrates how we constructed our forecast. The starting point on the left is what Powercor's opex for each year of the 2016–20 regulatory control period would be if it was set equal to Powercor's reported opex in 2014.

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<sup>29</sup> NER, cl. 6.5.6(d).

<sup>30</sup> NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

**Figure 7.4 AER final decision opex forecast (\$ million, 2015)**



Source: AER analysis.

Table 7.2 outlines the quantum of the difference between Powercor's revised proposed total opex and our final decision estimate for each year of the 2016–20 regulatory control period.

**Table 7.2 Proposed vs final decision total forecast opex (\$ million, 2015)**

	2016	2017	2018	2019	2020	Total
Powercor's revised proposal	233.1	240.1	249.1	256.1	264.7	1243.0
AER final decision	225.5	229.3	236.6	241.6	248.0	1181.1
Difference	-7.5	-10.8	-12.5	-14.6	-16.7	-62.0

Source: AER analysis.

Note: Excludes debt raising costs.

We outline the key elements of our alternative opex forecast and areas of difference between our estimate of opex and Powercor's estimate below.

## 7.4.1 Base opex

### Starting point for base opex

Consistent with our preliminary decision, we have based our opex forecast on Powercor's actual opex in 2014. We consider this leads to an opex forecast that reasonably reflects the opex criteria.

Our benchmarking indicates that the Victorian network service providers, including Powercor, are amongst the most efficient in the NEM. This suggests that it would be reasonable to rely on its actual opex when forecasting the base opex amount.

We also note that we regulate Powercor under an incentive-based regulatory framework. We would expect that Powercor, as a profit maximising service provider, would be responding to the financial incentives in the framework and would only incur cost increases where prudent. The incentive based framework gives us further confidence that in total Powercor's current opex is reasonably reflective of efficient levels.

We received some submissions that raised queries about the recent decline in productivity of the Victorian services providers and what it may mean for using actual opex in 2014 as the base opex.<sup>31</sup>

We have considered the recent productivity trend but it has not caused us to change our position on the efficiency of Powercor and the other Victorian service providers. We consider external drivers such as increases in bushfire mitigation obligations following the Black Saturday bushfires of 2009 and high labour price growth over the previous regulatory control period are the most significant drivers of the recent increases in opex for the Victorian service providers.

### Adjustment for Advanced Metering Infrastructure (AMI) costs

We have included an adjustment to our base opex forecast of AMI IT and communications costs. This is a change in position from the preliminary decision.

Following the expiry of the AMI Order-in-Council, opex associated with AMI is to be regulated under the NER. In the preliminary decision we allocated all these costs to alternative control services. This was intended to be an interim position before we considered this issue in more detail through the development of the Distribution Ring Fencing Guideline.

We received a number of submissions which disagreed with our preliminary position. We reconsidered our approach in light of these submissions.

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<sup>31</sup> VECUA, *Submission to the AER Preliminary 2016--20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 4, pp. 60-62; Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 25 February 2016, p. 11-12.

While there would be some benefit in waiting to consider this issue through the Ring Fencing Guideline process, given advanced meters have already been rolled out in Victoria, we acknowledge the cost allocation issues the Victorian service providers currently face are different to those that may potentially be faced by other service providers in other states. Therefore we agree that, on balance, there is no strong reason why we need to hold all these costs in alternative control services until the Distribution Ring Fencing Guideline is completed. We therefore have developed a revised position on how such costs should be allocated. We have allocated shared AMI costs across standard control services and alternative control services in accordance with cost allocation principles consistent with our Cost Allocation Guidelines and the cost allocation principles in the NER.

By applying these principles we have made an adjustment to Powercor's base opex of \$3.1 million (\$2015). As discussed in Attachment 16 the revised approach leads to a commensurate reduction in metering opex from our preliminary decision.

### Adjustment for corporate overheads

Consistent with our preliminary decision, we have included an adjustment for corporate overheads in our opex forecast. This reflects a change in Powercor's capitalisation policy for these costs. Whereas previously Powercor was partially capitalising these costs from 2016 it will fully expense them. This is the primary reason for the forecast increase in opex between 2015 and 2016.

Table 7.3 illustrates how we have constructed base opex.

**Table 7.3 Powercor - base opex (\$ million, 2015)**

	Our final decision
Reported 2014 opex	180.1
Remove debt raising costs	-0.2
Remove movement in provisions	-0.4
Remove DMIA expenditure	-0.2
Remove GSL payments	-2.2
Capitalisation policy adjustment	31.7
AMI cost reallocation	3.1
Other service classification changes	3.7
<b>Adjusted 2014 opex</b>	<b>215.5</b>
2015 increment	2.4
<b>Estimated 2015 opex</b>	<b>218.0</b>

Source: AER analysis.

We outline our detailed assessment of the base year in appendix A.

## 7.4.2 Rate of change

The efficient level of expenditure required by a service provider in the 2016–20 regulatory control period may differ from that required in the final year of the 2011–15 regulatory control period. Once we have determined the opex required in the final year of the 2011–15 regulatory control period, we apply a forecast annual rate of change to forecast opex for the 2016–20 regulatory control period. This accounts for the forecast change in opex due to price, output and productivity growth.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than Powercor's over the forecast period. Table 7.4 below compares Powercor's and our overall rate of change in percentage terms for the 2016–20 regulatory control period.

**Table 7.4 Forecast annual rate of change in opex (per cent)**

	2016	2017	2018	2019	2020
Powercor	2.67	2.84	3.15	3.15	3.17
AER	1.57	1.79	2.31	2.41	2.46
<b>Difference</b>	<b>-1.11</b>	<b>-1.05</b>	<b>-0.84</b>	<b>-0.74</b>	<b>-0.71</b>

Source: AER analysis.

Price growth and output growth drive the difference between our forecast rate of change and Powercor's.

### Price growth

To forecast labour price growth, Powercor used wage increases in its existing enterprise agreement for 2016, then used Frontier Economics' recommended extrapolation of long term enterprise agreements from a comparator group of service providers. We are not satisfied that Powercor's forecast of labour price growth reasonably reflects a realistic expectation of the cost inputs or the efficient costs that a prudent operator would require to achieve the opex objectives.

This is because Powercor's approach of using its current EA and an historical average of other EAs does not account for the broader labour market conditions expert economic forecasters expect to prevail in the forecast period. Further, Powercor's forecasting approach which uses two sources of forecasts over the 2016–20 regulatory control period is likely to result in an upwardly biased total forecast of labour price growth over the regulatory control period.

Powercor's forecast is higher than ours, which we base on forecasts from Deloitte Access Economics and CIE. Consequently, our forecast of price growth is on average 0.91 percentage points lower than Powercor's forecast.

We are satisfied that this approach to forecasting labour price growth reasonably reflects a realistic expectation of the labour price growth faced by a prudent and



efficient firm over the regulatory control period. This forward looking approach draws on available current market information from multiple sources, including from enterprise agreements (EAs), on the expected changes to the drivers of labour price.

### **Output growth**

Powercor forecast output growth using the same output growth measures and weightings we used in our preliminary decision. It updated its maximum demand forecasts and used the customer numbers and circuit length forecasts in our preliminary decision. We have also updated our output growth forecasts to reflect the output weights in our latest benchmarking report. Consequently we have forecast annual output growth 0.03 percentage points higher, on average, than Powercor did.<sup>32</sup>

We outline our detailed assessment of the rate of change in appendix B.

### **7.4.3 Step changes**

We have included step changes in our alternative opex forecast for the following proposals:

- mobile devices
- customer information system and customer relationship management
- RIN compliance
- introduction of Chapter 5A.

In total these step changes contribute \$10.2 million (\$2015) or 0.9 per cent to our total opex forecast for Powercor for the 2016–20 regulatory control period.

We consider these step changes represent the efficient and prudent costs of meeting new regulatory obligations or represent an efficient capex/opex trade-off.

We were not satisfied there were reasons to change our opex forecast for other step changes.

A summary of our conclusions are in Table 7.5.

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<sup>32</sup> In dollar terms, our forecast opex attributed to output growth is lower than Powercor's proposed opex forecast because we apply our estimate of output growth to a lower base level of opex.

**Table 7.5 Step changes (\$ million, 2015)**

	Initial proposal	Preliminary decision	Revised proposal	Final decision
Customer charter	0.5	–	-	-
Superannuation - accumulation members	4.6	–	-	-
Monitoring IT security	2.0	–	2.0	-
Mobile devices	4.1	–	3.5	3.5
Customer Information System and Customer Relationship Management	5.2	3.1	3.1	3.1
Introduction of cost-reflective tariffs	-	-	5.5	-
RIN compliance	-	-	2.5	2.5
Introduction of chapter 5A	-	-	1.0	1.0
<b>Total</b>	<b>18.3</b>	<b>3.1</b>	<b>17.7</b>	<b>10.2</b>

Source: AER analysis

We discuss each of the step changes Powercor proposed in more detail in appendix C.

#### 7.4.4 Other costs not included in the base year

We have assessed other costs not included in the base year. These include guaranteed service level (GSL) payments and debt raising costs. We outline our assessment of these GSL payments in appendix C and debt raising costs in attachment 3.

#### 7.4.5 Assessment of opex factors

In deciding whether we are satisfied the service provider's forecast reasonably reflects the opex criteria we have regard to the opex factors.<sup>33</sup>

Table 7.6 summarises how we have taken the opex factors into account in making our final decision.

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<sup>33</sup> NER, cl. 6.5.6(e).

**Table 7.6 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 an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period.</p> <p>We have used several assessment techniques that enable us to estimate the benchmark opex that an efficient service provider would require over the forecast period. These techniques include economic benchmarking and opex cost function modelling. We have used our judgment based on the results from all of these techniques to holistically form a view on the efficiency of Powercor's proposed total forecast opex compared to the benchmark efficient opex that would be incurred over the relevant regulatory control period.</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 Powercor'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>34</sup></p> <p>Powercor did not propose additional opex beyond that in its base opex to address the concerns of its electricity consumers.</p>
<p>The relative prices of capital and operating inputs</p>	<p>We have considered capex/opex trade-offs in considering Powercor's proposed step changes. For instance we have provided a step change for mobile devices on the basis that it is an efficient capex/opex trade-off. We considered the relative expense of capex and opex solutions in considering this step change.</p> <p>We have had regard to multilateral total factor productivity benchmarking when deciding whether or not forecast</p>

<sup>34</sup> AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
<p>The substitution possibilities between operating and capital expenditure.</p>	<p>opex reflects the opex criteria. Our multilateral total factor productivity analysis considers the overall efficiency of networks in the use of both capital and operating inputs with respect to the prices of capital and operating inputs.</p> <p>As noted above we considered capex/opex trade-offs in considering a step change for Powercor's mobile devices. We considered the substitution possibilities in considering this step change.</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 with in the use of both capital and operating inputs.</p> <p>Further, we considered the different capitalisation policies of the 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 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.</p>	<p>The incentive scheme that applied to Powercor's opex in the 2010–15 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach.</p> <p>We have applied our estimate of base opex consistently in applying the EBSS and forecasting Powercor's opex for the 2016–20 regulatory control period.</p> <p>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.</p>
<p>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).</p> <p>The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.</p>	<p>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 final decision.</p> <p>We have not found this factor to be significant in reaching our final decision.</p>

Source: AER analysis.

## A Base opex

As opex is relatively recurrent, we typically forecast based on a single year of opex. We call this the base opex amount. In this section, we set out our assessment of Powercor's base opex.

### A.1 Final decision

We have used a base opex amount of \$218.0 million (\$2015) in our final decision opex amount. The comparison of the base opex amount in our preliminary decision, Powercor's revised proposal and our final decision is outlined below in Table A.1.

**Table A.1 AER position on base opex (\$ million, 2015)**

	Preliminary decision	Revised proposal	Final decision
Reported 2014 opex	181.5	181.5	180.1
Remove debt raising costs	-0.2	-0.2	-0.2
Remove movement in provisions	-0.4	-0.4	-0.4
Remove DMIA expenditure	-0.2	-0.2	-0.2
Remove GSL payments	-2.2	-2.2	-2.2
Remove scrapping of assets	-0.7	-	-
Capitalisation policy change	32.0	32.0	31.7
AMI cost allocation	-	4.9	3.1
Other service classification changes	3.7	3.7	3.7
<b>Adjusted 2014 opex</b>	<b>213.3</b>	<b>219.1</b>	<b>215.5</b>
2015 increment	2.5	2.5	2.4
<b>Estimated 2015 opex</b>	<b>215.8</b>	<b>221.5</b>	<b>218.0</b>

Source: AER, *Powercor preliminary decision opex model*, October 2015; Powercor, *PAL PUBLIC MOD 1.36 - CP Opex Consolidation*, January 2016; AER, *Powercor final decision opex model*, May 2016.

### A.2 Powercor's revised proposal and submissions

In Powercor's revised proposal it proposed a base opex amount of \$221.5 million (\$2015).

The main difference between our preliminary decision and its revised proposal reflected a different allocation of AMI costs. In our preliminary decision we allocated all these costs to alternative control services opex. Powercor did not agree to this allocation.

Powercor also disagreed with the adjustment we had made to remove losses on the scrapping of assets.

We received several submissions in response to our preliminary decisions for the Victorian service providers which either disagreed with our conclusions on base opex or requested further evidence to support our decision. In particular, VECUA considered there is extensive evidence of material inefficiencies in some Victorian distributors' opex. It considered that this has been revealed by our benchmarking. As a result it considered using a revealed cost method to be flawed and a benchmarking approach should be used. It considered CitiPower to be the benchmark provider.<sup>35</sup>

More generally, VECUA considered that in setting base opex we have had insufficient regard to:

- the decline in the Victorian distributors' productivity over the previous regulatory control period
- increases in the Victorian distributors' opex over the previous regulatory control period
- the opex reductions that should be realised from the Victorian distributors' major capex programs over the previous regulatory period.<sup>36</sup>

The CCP was concerned we have presumed 2014 opex is efficient and that we have relied on it to set forecast expenditure in light of the recent decline in productivity. It also urged we review this in detail. It was not convinced that increased bushfire mitigation expenditure and expansion of the network were driving the decline in productivity.<sup>37</sup>

Further specific comments we received are addressed below.

### **A.3 Assessment approach**

In the Expenditure Forecast Assessment Guideline (the Guideline), we explain that a 'revealed cost' approach is our preferred approach to assessing base opex. If actual expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to actual expenditure for those cost categories forecast using the revealed cost approach.

We will use a combination of techniques to assess whether base opex reasonably reflects the opex criteria. If economic benchmarking indicates a service provider's base year opex is materially inefficient, our approach is to complement our benchmarking

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<sup>35</sup> VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 60.

<sup>36</sup> VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, pp. 4, 60–62.

<sup>37</sup> Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 25 February 2016, pp. 11–12.

findings with other analysis such as partial productivity indicators (PPIs), category-based techniques and detailed review.

Where a service provider proposes adjustments to base opex then we assess whether those adjustments would lead to a total opex forecast that reasonably reflects the opex criteria.

## A.4 Reasons for final decision

### Incentive regulation and the revealed cost forecasting approach

We have maintained our approach to setting Powercor's opex based on its actual opex in 2014. This approach is consistent with the approach we set out in the Guideline.

Network services are monopoly services with little scope in any given location for a competitor to duplicate the network efficiently.<sup>38</sup> Monopoly businesses do not have an incentive to set prices at an efficient level because there is no competitive discipline on their decisions. They do not need to consider how and whether or not rivals will respond to their prices. Monopolies' profits depend only on the behaviour of consumers, their cost functions, and their prices or the amount supplied.<sup>39</sup>

Without regulation, the resulting market power would lead to high prices and probably insufficient investment. Accordingly, we must regulate the prices and other aspects of these services to ensure reliable and affordable electricity.<sup>40</sup>

Information asymmetries make it difficult for us to accurately assess the efficiency of the network businesses' proposals. We need to make judgements about 'efficient' costs.<sup>41</sup>

Incentive regulation is used to partially overcome information asymmetries. We apply incentive-based regulation across all energy networks we regulate—consistent with the NER.<sup>42</sup> This is a fundamental aspect of the regime. As stated by the AEMC:

Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and

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<sup>38</sup> Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62, 2013*, p. 65.

<sup>39</sup> ACCC, *Submission to the Productivity Commission's inquiry into the economic regulation of airport services*, March 2011, p. 8.

<sup>40</sup> Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62, 2013*, p. 65.

<sup>41</sup> Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62, 2013*, p. 190.

<sup>42</sup> Clause 6.2.6(a) of the NER states that for standard control services, the control mechanism must be of the prospective CPI minus X form, or some incentive-based variant of the prospective CPI minus X form, in accordance with Part C (Building Block Determinations for standard control services). Further, the RPPs state a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.

what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.<sup>43</sup>

Broadly speaking, incentive regulation is designed to align the commercial goals of the business to the goals of society or, in the case of energy regulation, the NEO.<sup>44</sup> It relies on the principle that the network businesses' objective is to maximise profits.<sup>45</sup> Businesses that are able to improve their efficiency are rewarded with higher profits.<sup>46</sup> Businesses that allow their efficiency to deteriorate earn lower-than-expected profits. The actual revenue allowance set by the regulator should not influence the basic incentive of network businesses to minimise costs and, thereby, maximise profits. The drive to maximise shareholder returns should, in theory, push the businesses to become more efficient and productive over time. This allows us to leave the minutiae of input and output decision-making to the businesses.<sup>47</sup>

The revealed cost forecasting approach is consistent with this framework. As opex is relatively recurrent from year to year, the incentive framework gives us confidence that we can rely on a service provider's actual opex when forecasting their efficient opex for the next regulatory control period.

By using a revealed cost forecasting approach, we assume that any efficiencies which have occurred since our previous regulatory determination have already been reflected in a service provider's actual opex. For instance, to the extent there are any opex efficiencies that the businesses have realised through a recent capex program, we assume it would be reflected in its existing opex. Similarly, given the financial incentives these service providers face in avoiding unnecessary cost increases, we assume that any cost increases that have occurred since the last regulatory determination reflect a prudent and efficient response to particular changes in a service provider's operating environment.

For Victorian service providers, strong incentives have applied to opex for three regulatory control periods. We would expect a priori that in responding to these incentives, these service providers would already be delivering a service that is relatively efficient. As this provides a strong theoretical reason why the Victorian service providers would be operating relatively efficiently, to conclude one is in fact operating inefficiently, we would require a convincing alternative body of evidence across a number of sources. We are not aware of any such evidence.

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<sup>43</sup> AEMC, *Consultation paper: National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, February 2015, p. 3.

<sup>44</sup> Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62, 2013*, p. 188.

<sup>45</sup> Put simply, it is assumed that shareholders want the business to maximise profits because the greater the profits, the greater their income.

<sup>46</sup> As stated by the AER in its Expenditure Forecast Assessment Guideline explanatory statement, 'the ex-ante incentive regime provides an incentive to improve efficiency (that is, by spending less than the AER's forecast) because network businesses can retain a portion of cost savings made during the regulatory control period.' (p. 42)

<sup>47</sup> Productivity Commission, *Electricity Network Regulatory Frameworks, inquiry report no. 62, 2013*, pp. 27–28.



The main tool we have to assess whether incentive regulation is working is benchmarking. However, all the benchmarking we have undertaken, which was presented in our preliminary decision<sup>48</sup> shows that, on the whole, the Victorian service providers are operating relatively efficiently when compared to their counterparts in New South Wales and Queensland.<sup>49</sup> We do acknowledge the gap between the Victorian service providers and the NSW and Queensland service providers has narrowed in recent years on the MTFP and Opex MPFP benchmarks. However, as discussed in our annual benchmarking report<sup>50</sup> and below, changes in bushfire mitigation requirements including vegetation management are a significant driver of this outcome.

On this basis we have continued to rely on each of the Victorian service providers' actual opex to forecast and we have chosen not to undertake a forensic review of each of their opex. We consider this is a reasonable position to take in undertaking our task in assessing opex under the NER.

We also note that VECUA has inferred that because CitiPower is the best performer on one benchmarking model, the opex of all other Victorian service providers should be deemed to be inefficient.<sup>51</sup> We do not agree with this finding. Because benchmarking models are subject to limitations regarding specification of outputs and inputs, data imperfections and other uncertainties, we consider it is preferable to interpret the findings of any benchmarking conservatively. We do not consider it is reasonable to conclude that because one service provider is ranked highest in one model then all other service providers must be inefficient.<sup>52</sup>

### **Reasons for productivity decline/increase in opex in Victoria**

In response to the VECUA and CCP submissions, we have also considered the reasons for the decline in opex productivity across the Victorian service providers in the past period. This has not caused us to change our position on base opex from the preliminary decision.

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<sup>48</sup> AER, *Preliminary decision, Attachment 7*, pp. 31–40.

<sup>49</sup> Our preliminary decision was based on benchmarking we had presented in our most recent distribution benchmarking report published in November 2014 (AER, *2014 Annual benchmarking report*, November 2014). After releasing our preliminary decision in October 2015 we published an additional distribution benchmarking report in November 2015 (AER, *2015 Annual benchmarking report*, November 2015). The 2015 version of the report still indicates that the Victorian service providers are operating relatively efficiently compared to their counterparts in New South Wales and Queensland.

<sup>50</sup> AER, *2015 Annual benchmarking report*, November 2015, p. 8.

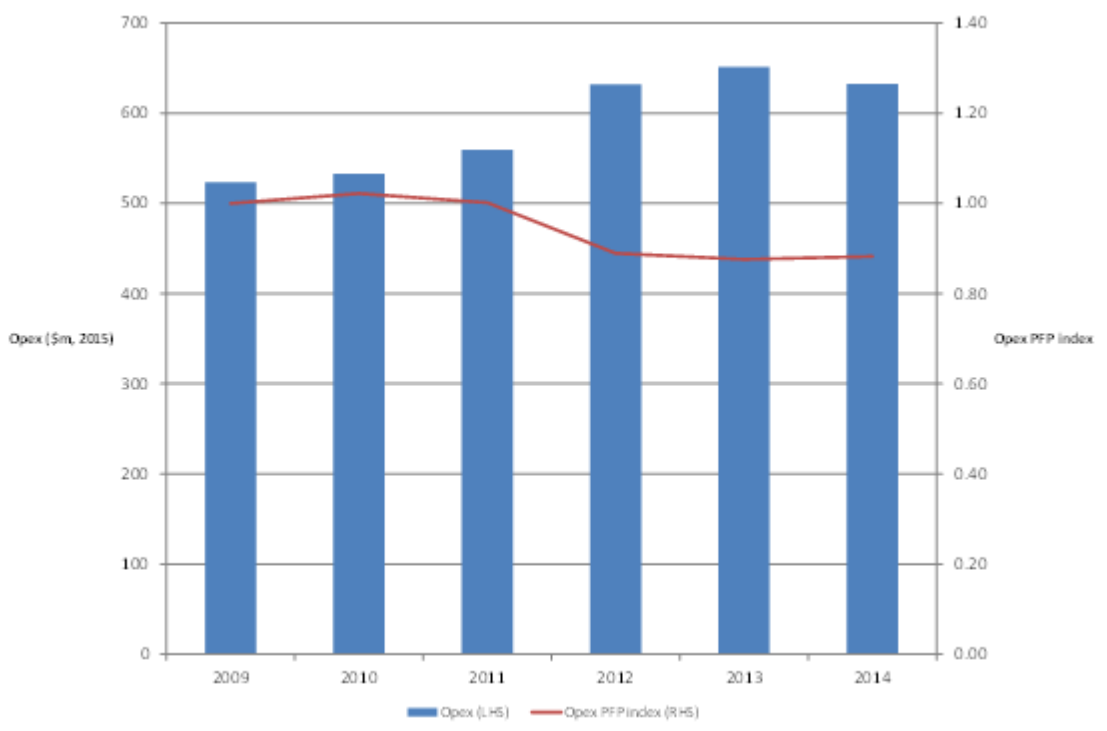
<sup>51</sup> VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 60.

<sup>52</sup> We also note the model VECUA refers to measured average opex efficiency over an eight year period (2006 to 2013). For the purposes of setting base opex we are reaching a conclusion on efficient opex for 2014. As the costs facing the Victorian service providers are different in 2014 to the average costs they faced from 2006 to 2013, it is not possible to directly infer 2014 efficiency by assessing 2006 to 2013 efficiency.

In total the Victorian service providers' opex have, on average, increased by 3.8 per cent per annum in real terms since 2009. We have observed the opex partial factor productivity (PFP) of the five Victorian service providers has declined by an average of 2.5 per cent per annum in this time. The opex PFP measure takes into account changes in customer numbers, circuit length, ratcheted maximum demand, energy delivered and customer minutes off supply. This suggests that a significant proportion of the growth in opex since 2009 is due to other cost drivers.

As outlined below in Figure A.1, the trend in opex and opex PFP has been relatively flat between 2009 and 2011. There is a significant increase in opex (and decline in opex PFP) across the Victorian service providers' between 2011 and 2012 and then a relatively flat trend in both opex and opex PFP between 2012 and 2014.

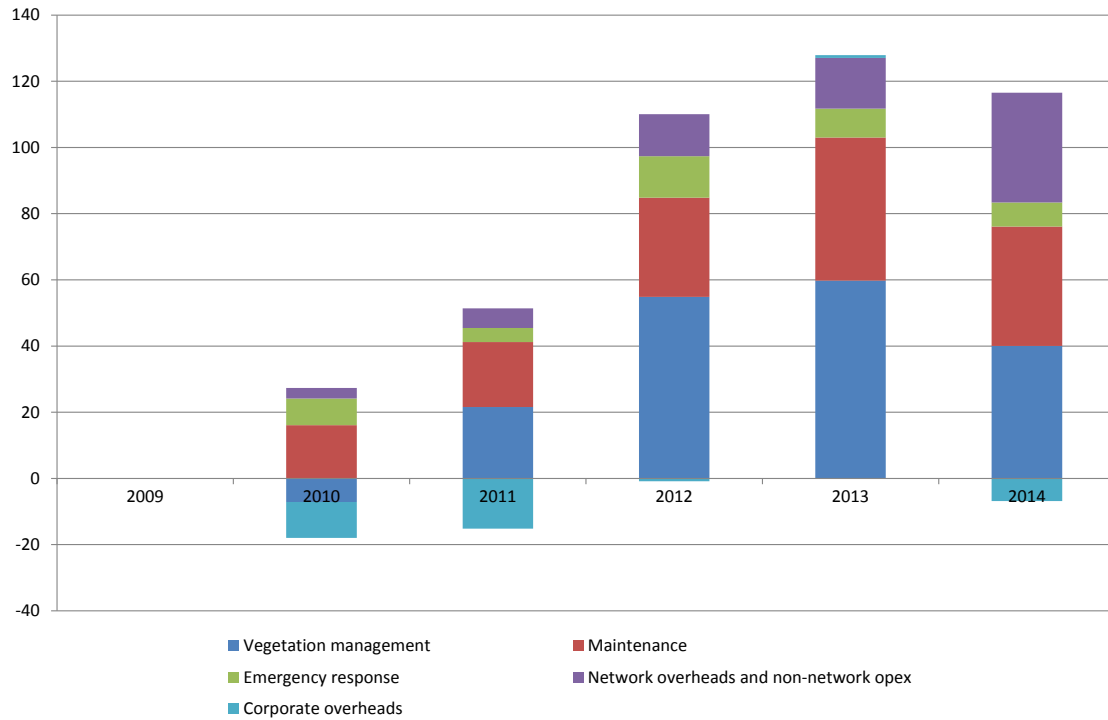
**Figure A.1 Victorian service providers - trend in opex and partial factor productivity in opex - 2009 to 2014 (\$ million, 2015)**



Source: AER analysis.

Figure A.2 aggregates total opex for each of the Victorian service providers by category and demonstrates the change in categories of opex in this time. It shows that increases in vegetation management opex followed by increases in maintenance opex are the main reasons why the Victorian service providers' opex has increased since our last determination.

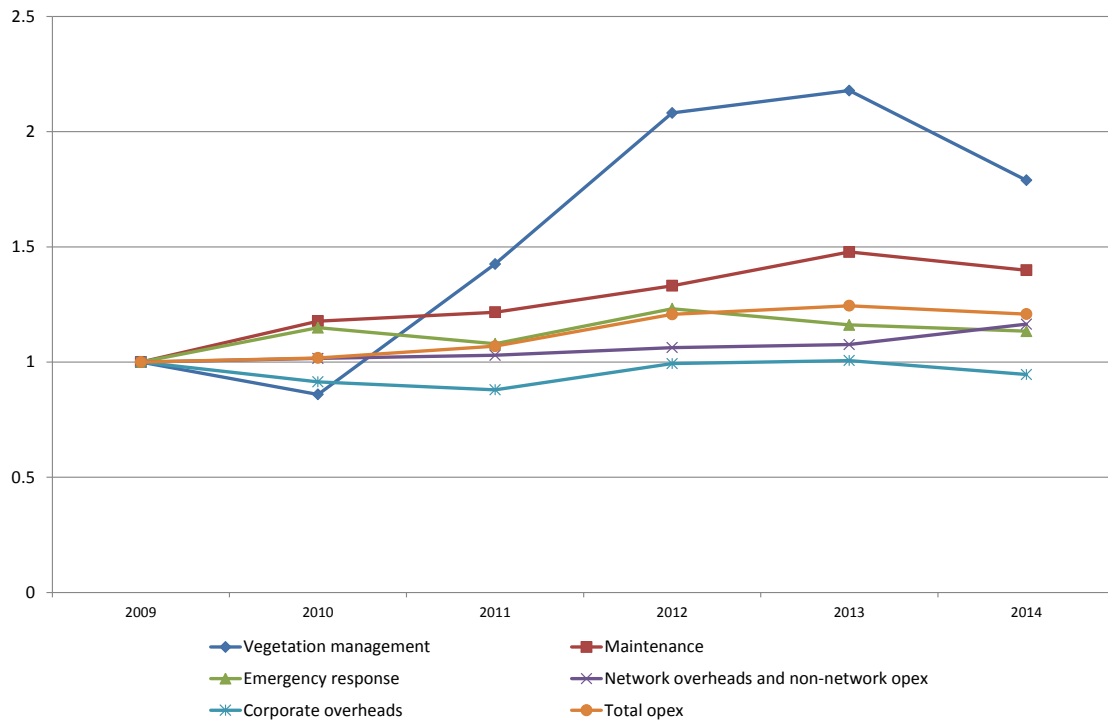
**Figure A.2 Change in Victorian service providers opex relative to 2009 (\$ million, 2015)**



Source: AER analysis.

Figure A.3 illustrates the growth of each category on an index based measure. Opex on vegetation management has increased proportionally by a much greater amount than other categories of opex. There has been a moderate increase in maintenance expenditure relative to 2009 levels. Network overheads allocated to opex and emergency response opex have increased only marginally relative to 2009 levels. Opex on corporate overheads has declined.

**Figure A.3 Change in opex relative to 2009 - index measure (\$ million, 2015)**



Source: AER analysis.

A major driver of the increase in vegetation management opex across the industry is attributable to the changes in regulatory requirements as a result of the *Electrical Safety (Electric Line Clearance) Regulations 2010* which was introduced in June 2010 following the Black Saturday bushfires. These new regulations introduced the following key changes to the Victorian service provider's regulatory requirements.

- Minimum clearance spaces surrounding aerial bundled cable or insulated cable now applied to small tree branches. Under the previous version of the regulations, the minimum clearance spaces did not apply to small tree branches under specified conditions.
- Minimum clearance spaces surrounding powerlines in hazardous bushfire risk areas now applied to tree branches above a powerline of 22kV. Under the existing regulations the minimum clearance space did not apply under specified conditions.<sup>53</sup>

We signalled that the *Electrical Safety (Electric Line Clearance) Regulations 2010* would be a significant cost driver affecting the Victorian service providers' opex when we forecast large step changes in opex in our final decisions for the 2011–15

<sup>53</sup> Victorian Competition and Efficiency Commission, *Proposed Electrical Safety (Electric Line Clearance) Regulations 2010 Regulatory Impact Statement*, pp. xviii-xix.

regulatory control period.<sup>54</sup> At the time, we forecast increases in opex of \$206 million (\$2015) from 2011 to 2015 due to these new regulations.<sup>55</sup>

Vegetation management expenditure across the industry was also likely affected by heavy rainfall during the period. The year 2010 was the fifth wettest year on record in Victoria following one of the wettest springs on record,<sup>56</sup> and 2011 was the twelfth wettest year on record.<sup>57</sup> While we have not collected evidence on the effects of this pattern on vegetation growth in Victoria, we did observe that above average rainfall in South Australia in 2010 and 2011 led to significant increases in vegetation growth and vegetation management expenditure.<sup>58</sup>

The moderate increase in maintenance expenditure across the industry in part also reflects other increases in regulatory obligations following the Black Saturday bushfires. For instance, one of the Victorian Bushfire Royal Commission's (VBRC) recommendations was to mandate maximum thirty seven month inspection cycles of single wire earth return lines (SWER) and 22KV feeders in high bushfire risk areas.<sup>59</sup> This came into force in the *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*<sup>60</sup> and is now mandated by the *Electrical Safety (Bushfire Mitigation) Regulations 2013*.<sup>61</sup> This has contributed to the increase in pole inspection expenditure in Figure A.4.

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<sup>54</sup> AER, *Victorian electricity distribution network service providers distribution determination 2011–15*, October 2010, p. 301; AER, *Opex step changes - final decision model*; AER analysis.

<sup>55</sup> Following an Australian Competition Tribunal decision, we reconsidered the amount we had forecast for CitiPower and Powercor. This led to a further increase in our forecast for CitiPower and Powercor of \$27 million (\$2015). See AER, *Vegetation management forecast operating expenditure step change 2011–15*.

<sup>56</sup> Bureau of Meteorology, <http://www.bom.gov.au/climate/current/annual/vic/archive/2010.summary.shtml>, 4 January 2011.

<sup>57</sup> Bureau of Meteorology, <http://www.bom.gov.au/climate/current/annual/vic/archive/2011.summary.shtml>, 3 January 2012.

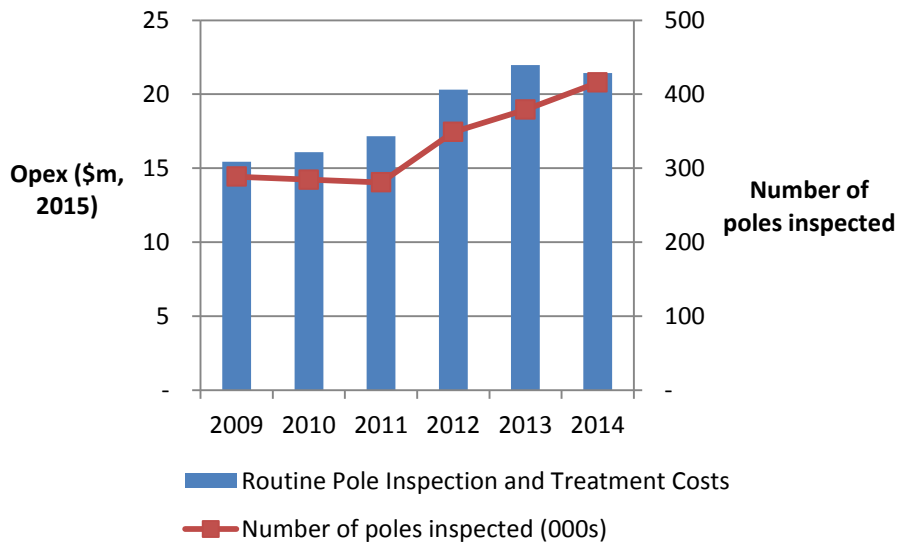
<sup>58</sup> AER, *SA Power Networks cost pass through application for vegetation management costs arising from an unexpected increase in vegetation management*.

<sup>59</sup> Victorian Bushfires Royal Commission, *Final Report - Summary*, July 2010, p. 29.

<sup>60</sup> *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 5A(j); *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 5A(j).

<sup>61</sup> *Electrical Safety Amendment (Bushfire Mitigation) Regulations 2011*, Cl. 6(i).

**Figure A.4 Pole inspection and pole inspection expenditure (\$ million, 2015)**



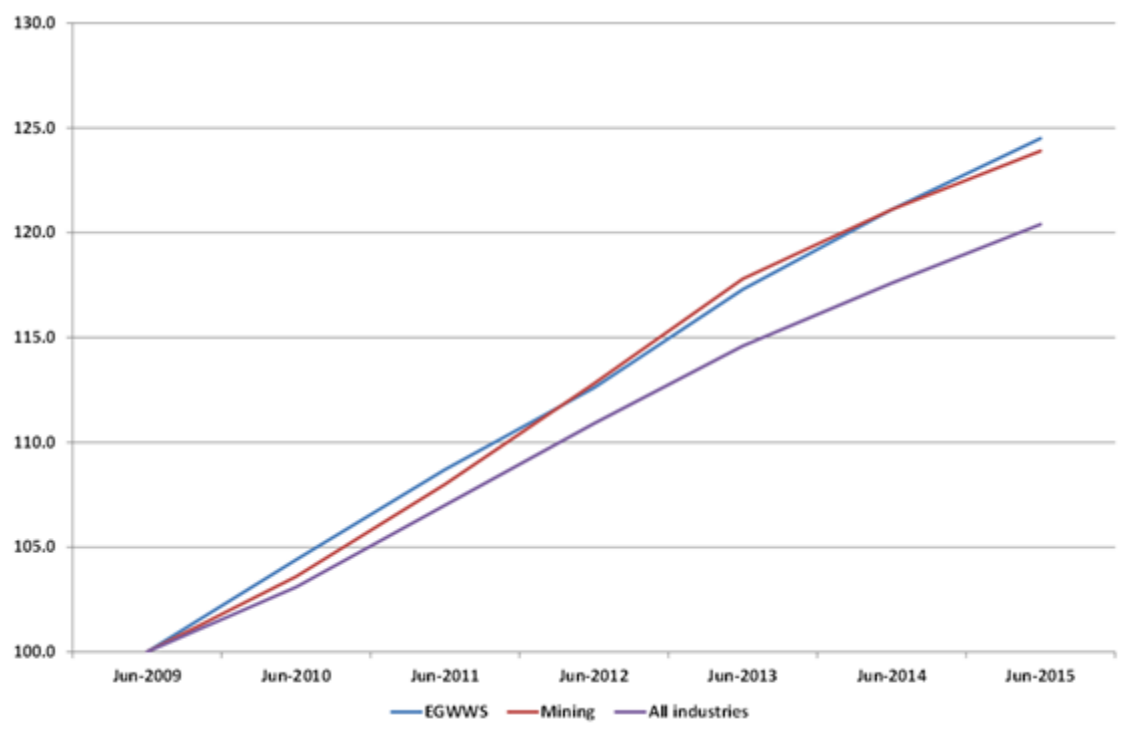
Source: AER analysis.

Another factor contributing to the increase in maintenance opex and opex more generally is the strength in wage growth across the industry. Labour costs are the most significant component of opex for utility businesses.

Since 2009, wage growth in the ABS' Electricity Gas Water and Wastewater (EGWWS) classification has been on average 3.7 per cent per annum in nominal terms. As indicated in Figure A.5, this has largely matched the rate of wage growth in the mining industry and has exceeded wage growth across the Australian economy. This, in part, is likely to reflect the impact of the mining boom on the EGWWS sector. The impact of the demand for mining labour has previously been recognised as a driver of utilities wages by Deloitte and BIS Shrapnel.<sup>62</sup>

<sup>62</sup> Access Economics, *Forecast growth in labour costs: update of March 2010 report*, September 2010, p. vii; BIS Shrapnel, *Labour Cost Escalation Forecasts to 2016–17 - Australia and Queensland*, January 2012, p. 21.

**Figure A.5 Wage growth - ABS classifications**



Source: ABS, 6345.0 Wage Price Index, December 2015.

In our view, the above drivers do not suggest that the Victorian service providers' operating efficiency has materially declined over the previous regulatory period. In our view it suggests there are a number of changes in business conditions that help to explain the trend since our last revenue determination in Victoria.

Importantly, we do not expect these drivers to persist in the 2016–20 regulatory control period. For instance, the *Electrical Safety (Electric Line Clearance) Regulations 2015* led to relatively minimal changes to the Victorian service providers' regulatory requirements for vegetation management. As discussed in Appendix B, we also expect efficient wage growth in the utility sector to slow. This is in part attributable to the reduced competition for labour from the mining sector.<sup>63</sup>

## **A.5 Allocation of AMI costs**

Our final position on base opex incorporates an adjustment of \$3.1 million for AMI Information Technology (IT) costs. This is a change in position from our preliminary decision where we allocated all AMI costs to alternative control services. Our revised approach is based on advice on cost allocation principles for IT and communications systems from Energy Market Consulting Associates (EMCa). These principles are

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<sup>63</sup> Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, February 2016, p. 39.

aligned with the cost allocation principles in our Cost Allocation Guidelines and in the NER.

### **Preliminary decision approach and consideration of stakeholder views**

During the 2011–15 regulatory control period, incremental costs associated with implementing and operating smart meters were regulated under the Advanced Metering Infrastructure Order in Council (AMI OIC). This included costs associated with new or upgraded IT systems.

With the expiry of the AMI OIC, opex associated with AMI is now to be regulated under the NER. Powercor initially proposed an adjustment to its base opex of \$4.9 million (\$2015) for IT metering expenditure previously regulated under the AMI OIC. Other opex associated with smart meters was allocated to alternative control services metering. This led to a base opex amount for alternative control services metering of \$12.9 million (\$2015) from 2017.<sup>64</sup>

Powercor considered that while many of its IT systems originally needed upgrading or replacing to facilitate the AMI rollout, these systems are now predominantly used to deliver standard control services. It considered that whether or not it owns or operates the metering assets, it will still need to operate and maintain its IT systems in order to continue to deliver standard control services.<sup>65</sup>

In our preliminary decision we did not allocate any AMI costs to standard control services. Each of the Victorian service providers had adopted a different approach to allocating AMI costs in their initial proposals. Presently, metering services are not subject to competition but, following NER changes, competition is scheduled to begin from December 2017.<sup>66</sup> We considered that a different approach to allocating costs across each of the Victorian service providers would not help in promoting effective competition. We considered a consistent approach to be preferable which could be dealt with through our Distribution Ring Fencing Guideline in accordance with a national framework.<sup>67</sup> We are scheduled to publish a Distribution Ring Fencing Guideline by 1 December 2016.

In the interim, before this Guideline is developed, we considered it was preferable to allocate all AMI costs to alternative control services. As this is similar to the historical approach where AMI costs are recovered separately to most distribution network costs, we also considered this approach will help in promoting transparency around trends in AMI and standard control expenditure.<sup>68</sup>

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<sup>64</sup> 2016 was \$13.5 million (\$2015).

<sup>65</sup> Powercor, *Appendix F - Base Year Adjustments*, April 2015, p. 11.

<sup>66</sup> AEMC, *National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2015*, 26 November 2015, p. i.

<sup>67</sup> AER, *Powercor preliminary decision*, October 2015, Attachment 7, p. 44.

<sup>68</sup> AER, *Powercor preliminary decision*, October 2015, Attachment 7, p. 44.



In response to our preliminary decision, all of the Victorian service providers disagreed with the AER's decision to allocate all AMI costs, to metering ACS. All of the Victorian service providers maintained that certain AMI costs should be allocated to standard control services.

The Victorian service providers' arguments to support their proposals to allocate some AMI costs to SCS can be summarised as follows:

- a number of the IT systems rolled out as part of the AMI metering service are needed even if the service providers did not provide a metering service e.g. for customer billing and providing data to the market, and should therefore be considered to contribute to the distribution network SCS<sup>69</sup>
- as some of these costs should be allocated to SCS, in the event of metering competition, they would be at an unfair disadvantage if all AMI costs are allocated to ACS<sup>70</sup>
- costs must be correctly allocated now in line with the regulatory framework.<sup>71</sup> Several service providers considered costs should be allocated in accordance with their Cost Allocation Methods (CAM)<sup>72</sup>
- different DNSPs adopted different approaches to the AMI roll out (e.g. purpose built IT systems compared to upgrades / lifecycle replacement of existing systems) and these differences limit the extent to which cost allocation between standard control services and alternative control services will or can be consistent across all DNSPs.<sup>73</sup>

The Victorian Government also disagreed with our preliminary decision on this issue. It considered we must resolve this issue to the best of our ability now.<sup>74</sup> It considered that if all AMI costs are allocated to ACS then metering charges will be higher than they should be. It considered that there is a risk that this may encourage inefficient entry from new competitors.<sup>75</sup> The CCP agreed with our preliminary decision to allocate all

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<sup>69</sup> AusNet Services, *Revised regulatory proposal, Attachment 11-6*, 6 January 2016; CitiPower, *Revised regulatory proposal*, 6 January 2016, p. 151; Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 150-151.

<sup>70</sup> AusNet Services, *Revised regulatory proposal, Attachment 11-7*, 6 January 2016; CitiPower, *Revised regulatory proposal*, 6 January 2016, p. 151; Jemena, *Revised regulatory proposal, Attachment 9-1*, 6 January 2016, p. 23; Powercor, *Revised regulatory proposal*, 6 January 2016, p. 151; United Energy, *Revised regulatory proposal*, 6 January 2016, p. 106.

<sup>71</sup> Jemena, *Revised regulatory proposal, Attachment 9-1*, p. 22; United Energy, *Revised regulatory proposal*, 6 January 2016, pp. 104-105.

<sup>72</sup> AusNet Services, *Revised regulatory proposal, Attachment 11-7*, 6 January 2016; CitiPower, *Revised regulatory proposal*, 6 January 2016, pp. 152-153; Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 152-153.

<sup>73</sup> CitiPower, *Revised regulatory proposal*, 6 January 2016, p. 152; Jemena, *Revised regulatory proposal, Attachment 9-1*, 6 January 2016, p. 24; Powercor, *Revised regulatory proposal*, 6 January 2016, p. 152; United Energy, *Revised regulatory proposal*, 6 January 2016, p. 105.

<sup>74</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20*, 14 January 2016, p. 10.

<sup>75</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016-20*, 14 January 2016, p. 10.

AMI costs to ACS metering pending development of the Distribution Ring Fencing Guideline.<sup>76</sup>

In light of the several submissions we received from stakeholders that disagreed with our preliminary position, we reconsidered whether we should continue to hold all AMI costs in ACS metering until we considered this issue further in developing the Distribution Ring Fencing Guideline. We have determined that a change in position from our preliminary decision is appropriate. We note that the mandated AMI roll-out involved upgrades not just to metering services but also other network services, such as IT and other systems which previously were being recovered in aggregate under the AMI OIC regime, but are now regulated under the NER. This means certain systems should be seen as part of SCS.

While there would be some benefit in waiting to consider this issue through the Distribution Ring Fencing Guideline process, given advanced meters have already been rolled out in Victoria, the cost allocation issues the Victorian service providers currently face are different to those that may potentially be faced by other service providers in other states. Therefore, on balance, it is appropriate to consider the allocation of AMI costs between SCS and ACS, notwithstanding we have not yet completed the Distribution Ring Fencing Guideline. We therefore have developed a revised position on how such costs should be allocated for the 2016–20 regulatory control period.<sup>77</sup>

### **EMCa advice on cost allocation**

We engaged EMCa to help develop a cost allocation approach that could be applied across the Victorian service providers. We asked EMCa to focus on IT and communications costs as this was the main area where the service providers proposed to allocate costs to SCS.

EMCa carried out a desktop review of the AMI information submitted by the Victorian service providers as part of their regulatory submissions. It also reviewed relevant AMI regulatory decision and guidance documents. It compared the allocation approach for AMI-related IT and communications expenditure and collated evidence on the key drivers and rationale provided by each business to justify the allocation approaches taken.<sup>78</sup>

EMCa also reviewed the allocations proposed by the businesses against our cost allocation framework, which include:

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<sup>76</sup> Consumer Challenge Panel Sub Panel 3, *Report on AER Preliminary Decisions and DNSPs' Revised Proposals*, 25 February 2016, p. 23.

<sup>77</sup> We note that our decision to allocate these costs in this way for the 2016–20 regulatory control period does not prevent us from re-considering this issue through the Ring Fencing Guideline process.

<sup>78</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. 2.

1. the cost allocation principles in the NER<sup>79</sup>
2. our Cost Allocation Guideline<sup>80</sup>
3. approved Cost Allocation Methods for each service provider.<sup>81</sup>

EMCa agreed that it is reasonable that some proportion of the costs relating to AMI should be allocated to SCS as some aspects of AMI were geared towards providing greater network benefits beyond metering services.

While EMCa considered it reasonable to suggest that the allocation of AMI costs should be consistent with each service provider's CAM, for the most part it did not consider their CAMs are sufficiently prescriptive or granular as to provide a clear method for allocating AMI costs between metering ACS and SCS:

While noting the AER's Decisions approving the CAMs, given the high-level nature of the documents it is not possible to assess from the CAMs alone, whether the DNSPs have adopted a cost allocation approach for metering-related IT and communications that is consistent with NER's CAG. Moreover the variety of methods used by the DNSPs in allocating costs between SCS and metering ACS directly demonstrates the latitude in interpretation that has been applied in the CAMs.<sup>82</sup>

EMCa considers it is more instructive to allocate such costs by direct reference to the NER's Cost Allocation Principles (CAP) and our Cost Allocation Guidelines (CAG). By basing the allocation of AMI costs on consistent principles with reference to the main reason the system was put in place (i.e. driver), EMCa considers this would provide a more reasonable platform for metering competition.<sup>83</sup>

In line with our CAG and the NER's CAP, EMCa considers that costs should be directly attributed (to distribution network SCS or metering ACS) only where the relevant systems are solely used to provide that service or where use for the other services can be considered immaterial as defined by Australian accounting standards. Where costs are shared and material, EMCa recommends the costs be allocated on a causal basis.<sup>84</sup>

On this basis EMCa would expect DNSPs to propose an attribution / allocation of IT opex and communications opex broadly as set out in Table A.2.

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<sup>79</sup> NER, s.6.15.2.

<sup>80</sup> AER, *Electricity distribution network service providers - Cost allocation guideline*, June 2008.

<sup>81</sup> AusNet Services, *Cost Allocation Method*, November 2014; CitiPower, *Cost Allocation Method*, April 2014; Jemena, *Cost Allocation Method*, July 2014; Powercor, *Cost Allocation Method*, April 2014; United Energy *Cost Allocation Method*, October 2014.

<sup>82</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. 22.

<sup>83</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

<sup>84</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

**Table A.2 Proposed allocation of AMI IT and communications costs**

Allocation between ACS/SCS	
Allocated solely to ACS metering	<p>Communications infrastructure opex including Network Management Systems (NMS), Metering Management Systems (MMS), Network Operations and Control Centre (NOCC)</p> <p>Metering data management systems</p>
Allocated solely to SCS	<p>Field force mobility systems</p> <p>Network billing systems</p> <p>Customer Information Systems</p> <p>Outage management systems</p>
Shared between ACS and SCS	<p>B2B systems for managing AMI- related transactions with other market participants</p> <p>GIS</p> <p>Asset management systems</p> <p>Performance and reporting regulatory systems</p> <p>Middleware / integration bus technology</p> <p>Data analysis systems</p> <p>New / upgraded IT infrastructure to support the additional AMI functionality</p>

Source: EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

Several service providers considered that a common allocation method would be challenging to apply given they implemented AMI at different stages of their IT lifecycles. However, EMCa did not afford this much weight given it had recommended the service providers apply a causal allocation method. This gives consideration to the reason the cost was incurred and recognises the different stage of the service providers' IT lifecycles. EMCa considered the service providers' arguments would only be relevant if it were advocating the same fixed allocation percentage be used across all service providers.<sup>85</sup>

<sup>85</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

## Application of cost allocation principles to Powercor's AMI costs

We invited Powercor to comment on EMCa's draft framework for allocating AMI costs to which it responded on 24 March.<sup>86</sup>

For the most part, Powercor considered its approach aligned with EMCa's framework. However, Powercor disagreed that its metering data management system (MDMS), Itron Enterprise Edition (IEE) should be solely allocated to alternative control services. IEE is Powercor's platform for data collection, validation, storage and process. It considered that if the distribution service was operated independently of the metering service, the distribution service would still require systems that undertook collection, validation, storage and processing solely for network purposes. It therefore considered it to be a shared system.<sup>87</sup> AusNet, Powercor and Jemena, in their responses to EMCa's draft report also considered that the costs of MDMS should be shared between SCS and ACS metering.<sup>88</sup>

To identify whether a system should be solely related to the provision of metering services, EMCa considered the main reason the system was implemented (i.e. driver). As a metering data management system captures, processes, stores and makes available metering data, EMCa considers that this system should be solely allocated to metering. EMCa does not consider the fact that the metering data is also used within the distribution business should mean the parts of the cost of the system should be allocated to SCS. EMCa notes future metering service providers in the NEM would all require an MDMS to provide metering services. It therefore maintained its advice to allocate all these costs to ACS metering.<sup>89</sup>

Based on EMCa's advice, we are satisfied that the driver of implementing an MDMS is to provide a metering service. Therefore, we agree that these costs should be solely allocated to ACS metering. As competitors for metering will all require an MDMS that cannot be recovered through network tariffs, this allocation approach will help to ensure that future competitors for metering are not unfairly disadvantaged.

We also consider EMCa's advice is consistent with our approach to service classification which classifies metering data services as an alternative control service.<sup>90</sup> These services are defined as the collection, processing, storage, delivery and management of metering data.

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<sup>86</sup> Powercor, *RE: AER information request – Powercor - #050 – Advanced Metering Infrastructure costs* [email to AER], 24 March 2016.

<sup>87</sup> Powercor, *AER information request – Powercor - #044 – Advanced Metering Infrastructure costs.pdf* [email to AER], 24 March 2016.

<sup>88</sup> AusNet, *IR#051 - AusNet Response* [email to AER], 24 March 2016; Jemena, *AER JEN IR#049.pdf* [email to AER], 24 March 2016; Powercor, *RE: AER information request – Powercor- #050 – Advanced Metering Infrastructure costs* [email to AER], 24 March 2016.

<sup>89</sup> EMCa, *Advice on allocation of advanced metering infrastructure (AMI) IT and communications expenditure*, 6 April 2016, p. iii.

<sup>90</sup> AER, *Final framework and approach for the Victorian electricity distributors*, 24 October 2014, p. 49.

This revised allocation leads to a greater proportion of IT costs allocated to alternative control services metering than Powercor's revised proposal in two respects:

1. IEE costs are allocated solely to alternative control services - metering
2. A greater percentage of support costs for IEE and Powercor's Market Transaction System (MTS) system are allocated to alternative control services metering in line with the revised allocation of IEE.<sup>91</sup>

Table A.3 illustrates how (in percentage terms) the allocation of IT and communications costs has changed between Powercor's initial proposal, revised proposal and our final decision.

**Table A.3 Allocation of IT and communications costs (per cent)**

Initial proposal		Revised proposal		Final decision	
SCS	ACS	SCS	ACS	SCS	ACS
67	33	67	33	43	57

Source: Powercor, Regulatory proposal, PAL PUBLIC MOD 1.2 PAL Metering Capex & Opex – public version, April 2015; Powercor, Revised Regulatory proposal, PAL PUBLIC RRP MOD 1.2 PAL Metering Capex & Opex, January 2016; AER analysis.

## A.6 Other adjustments to base opex

### Corporate overheads

We have maintained an adjustment to base opex for corporate overheads.

In our preliminary decision, we accepted an adjustment to base opex for a change in Powercor's capitalisation policy in relation to corporate overheads. Whereas previously Powercor partially capitalised these costs, from 2016 it proposes to fully expense them. Consistent with its approved Cost Allocation Method (CAM), we accepted this adjustment.<sup>92</sup> This was the main reason our estimate of forecast opex increased relative to Powercor's historical opex.<sup>93</sup>

However, we used a different amount to what Powercor proposed in our preliminary decision opex forecast. Powercor proposed the adjustment be based on its 2014

<sup>91</sup> Our preliminary decision also has incorporated other changes Powercor made to its cost allocation in its 24 March response to our information request for the costs of its Market Transaction Service, Oracle, and Data Management Systems. Powercor's revised allocation approach for these systems appears reasonable based on EMCa's principles. The effect of this change is relatively minor.

<sup>92</sup> AER, *Preliminary decision, Attachment 7*, October 2015, pp. 40–41.

<sup>93</sup> VECUA estimated that our preliminary decision opex forecast was 30 per cent higher than Powercor's actual opex in 2011–15. See VECUA, *Submission to the AER Preliminary 2016-20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 58.

capitalised overheads. For a number of reasons we considered an average of 2012 to 2014 capitalised overheads was preferable to Powercor's approach.<sup>94</sup> In particular:

- Expenditure in a single year is often affected by non-recurrent factors. If these costs are higher than average in the most recent audited year, forecast opex would be higher than required to meet the opex objectives. We observed that Powercor's capitalised corporate overheads in 2014 was materially higher than earlier years and we considered this could have been affected by non-recurrent factors in this year.
- No incentive mechanism applied to Powercor's capex in the 2011–15 regulatory control period. Without such a mechanism, its incentive to incur efficient capex declined over the 2011–15 period. This means, all else being equal, it was incentivised to delay its capital expenditure towards the end of the period. There was a relatively weak incentive applying to capitalised corporate overhead expenditure in 2014.<sup>95</sup>

Powercor accepted our adjustment for capitalised corporate overheads in its revised proposal. However, the Victorian Government considered it was unclear why we had chosen an average of Powercor's 2012 to 2014 capitalised corporate overheads. It suggested an average of 2010 to 2014 to be preferable because it would be equivalent to applying an efficiency sharing scheme. It also notes it is consistent with the way we apply STPIS targets.<sup>96</sup>

The methodology we use when forecasting is matter of judgement. If we use an average of historical costs, the longer the period, the greater the risk is that we would be taking into account information which is no longer relevant - such as the growth in customer numbers, change in regulatory requirements or efficient wage levels. In this instance, it is our judgement that a three year average is sufficient to ensure that the adjustment for Powercor's corporate overheads is not unduly influenced by non-recurrent factors. We do not consider our adjustment needs to replicate the outcomes if an efficiency sharing scheme were in place, or our opex forecasting approach needs to be consistent with how STPIS targets are set.

Origin Energy also commented on this adjustment. Its main concern was that Powercor (and CitiPower) allocated these costs to opex in knowledge that their opex is relatively more efficient than their capex and within the AER's revised benchmark. As a result, it considered that overhead costs that may not have been deemed efficient if they had been allocated to capex have now been included in allowed revenues.<sup>97</sup>

Origin Energy did not articulate why it considered Powercor, by reporting overheads as opex, avoided cuts to its capex program. We do not see how reporting these costs as

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<sup>94</sup> AER, *Preliminary decision, Attachment 7*, October 2015, p. 42.

<sup>95</sup> AER, *Preliminary decision, Attachment 7*, October 2015, pp. 40–43.

<sup>96</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' preliminary distribution determinations for 2016–20*, 14 January 2016, pp. 7–8.

<sup>97</sup> Origin Energy, *Submission on AER preliminary decision VIC EDPR 2016-20*, 6 January 2016, p. 1.



opex would have materially affected our assessment of their relative efficiency. We note that corporate overhead benchmarking suggests Powercor's total corporate overheads are relatively low on a per customer basis.<sup>98</sup> We also note that Powercor's change in capitalisation policy was first signalled to us in April 2014 before we first published the results of our economic benchmarking later that year.

Origin Energy is also concerned that there appears to be a lack of consistency in the application of cost allocation. It is concerned that businesses were allowed to amend their cost allocators year on year to achieve preferential regulatory outcomes.<sup>99</sup> While we do allow businesses to allocate costs differently from time to time, it is subject to the approved CAM at the time and consistency with the Cost Allocation Guidelines (CAG). Whether it is desirable to achieve consistent cost allocation methodologies across all businesses, is a broader regulatory issue that is best considered as part of any future reviews of our CAG.

### **Losses on the scrapping of assets**

We no longer propose to make an adjustment for losses on the scrapping of assets.

In our preliminary decision, we proposed to make an adjustment to Powercor's base opex to remove what we understood to be losses on the scrapping of assets.<sup>100</sup>

Losses on the scrapping of assets are accounting records of the shortfalls between the proceeds from selling assets and their accounting written down values. We considered that as a loss on the scrapping of an asset is an accounting adjustment to expenditure, rather than an actual outlay made in providing network services, it was not something which should be recovered from consumers. We decided to make this adjustment after accepting a proposal by Jemena. We based our adjustment on information provided by Powercor in response to an information request.

Powercor has clarified that it reports losses on assets as negative income rather than opex. We accept its explanation and therefore do not propose this adjustment in our final decision.

### **Inflation**

The other change to our base opex estimate reflects an update of how we have inflated base opex from nominal dollars to real \$2015. For our preliminary decision we estimated the annual inflation rate to December 2015 would be 2.5 per cent, based on the RBA's forecast in its statement on monetary policy.<sup>101</sup> For this final decision we have used the actual inflation rate of 1.7 per cent as reported by the ABS.<sup>102</sup> This actual inflation rate was not available at the time of our preliminary decision.

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<sup>98</sup> AER, *Ergon Energy preliminary decision*, October 2014, p. 7-150.

<sup>99</sup> Origin Energy, *Submission on AER preliminary decision VIC EDPR 2016–20*, 6 January 2016, p. 2.

<sup>100</sup> AER, *Preliminary decision, Attachment 7*, October 2015, p. 46.

<sup>101</sup> Reserve Bank of Australia, *Reserve Bank of Australia statement of monetary policy*, August 2015, p. 67.

<sup>102</sup> ABS catalogue 6401.0, December 2015.



## B Rate of change

Once we have determined the efficient opex required in 2015 we apply a forecast annual rate of change to forecast opex for the 2016–20 regulatory control period. We do this to account for likely changes in demand and cost inputs for each year of the forecast period. As set out in the Expenditure Forecast Assessment Guideline (the Guideline), the rate of change accounts for forecast:<sup>103</sup>

- price growth
- output growth
- productivity growth.

This appendix contains our assessment of the opex rate of change for use in developing our estimate of total opex.

### B.1 Position

We are not satisfied Powercor's proposed rate of change for the 2016–20 regulatory control period reasonably reflects the opex criteria.<sup>104</sup> There are four elements of Powercor's proposal with which we are not satisfied:

1. Powercor's approach to forecasting labour price growth relies on current and historical enterprise agreements (EAs). This approach:
  - takes no account of expected labour market conditions in the forecast period despite evidence that labour market conditions for electricity workers are not likely to be as strong in the forecast period as they have been historically
  - is inconsistent with providing effective incentives in order to promote economic efficiency through the negotiation of efficient wages<sup>105</sup>
  - does not use the same forecasting approach for all years of the forecast period. Powercor's forecasting approach is likely to result in an upwardly biased total forecast of labour price growth over the regulatory control period, even assuming Powercor acted prudently and efficiently when entering into its current EAs
  - relies on an incorrect interpretation of 'regulatory obligation or requirement' in the NEL.<sup>106</sup>
2. Powercor's approach treats all field services contract expenditure as labour. This assumes that the price growth of field contractors' non-labour inputs is the same as their labour. Consequently, Powercor applied a higher weighting to labour price

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<sup>103</sup> AER. *Better Regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 61.

<sup>104</sup> NEL, cl. 6.5.6(c).

<sup>105</sup> NEL, s. 7A(3).

<sup>106</sup> NEL, s. 2D.

growth in determining the mix of labour and non-labour price growth, which it based on an average of its actual expenditure over the three year period 2012 to 2014. In our view, this overstates the cost inputs required by a prudent and efficient DNSP in the forecast period.

3. Powercor included forecast real price growth for non-labour expenses. We are not satisfied, however, that Powercor's forecast reflects the growth in non-labour prices overall.
4. Powercor did not ratchet its forecast maximum demand in its output growth forecast, meaning the capacity Powercor has installed to satisfy demand is not properly recognised. This overstates the increase in output Powercor requires to meet its opex objectives.

Since we are not satisfied that Powercor's proposed rate of change will produce a total opex forecast that reasonably reflects the opex criteria, we must not accept it and we must develop our own estimate.<sup>107</sup> Our estimate of the rate of change forecasts:

- labour price growth based on the forecast growth in the wage price index (WPI) for the Victorian electricity, gas, water and waste services (utilities) industry. We have used the average of the Victorian utilities WPI forecasts from Deloitte Access Economics (DAE) and the Centre for International Economics (CIE). Consistent with expert advice from Economic Insights, we have applied input price weights of 62 per cent for labour and 38 per cent for non-labour, which reflect the weights of an efficient benchmark firm, to forecast total price change.
- output growth based on the weighted average growth of customer numbers (73.9 per cent), circuit line length (8.7 per cent) and ratcheted maximum demand (17.4 per cent).
- no growth in productivity, which is consistent with Powercor's proposal.

We consider that applying our method to derive an alternative estimate of opex will result in a forecast that reasonably reflects the efficient and prudent costs faced by Powercor given a realistic expectation of demand forecasts and cost inputs. This is because:

- our labour price growth measure reasonably reflects current and forecast economic conditions , including the wage increases in current EAs
- our labour and non-labour price weightings reasonably reflect the benchmark efficient mix of labour services and other costs required to provide distribution services
- our output growth measure reasonably reflects the forecast increase in services that customers require.

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<sup>107</sup> NER, cl. 6.5.6(d), 6.12.1(4)(ii).

In the sections below we discuss the reasons why we consider Powercor's approach to forecasting the rate of change will not produce an opex forecast that reasonably reflects the opex criteria. We also provide our reasons why our approach to forecasting the rate of change will provide an opex forecast that reasonably reflects the opex criteria.

We have applied the same rate of change method to derive our alternative estimate of opex as we used in our preliminary decision. However, we have updated our estimate of the rate of change in opex to reflect the most recent forecasts of labour price growth in the Victorian utilities industry available from expert economic forecasters. The net impact of these changes results in an annual rate of change of 1.86 per cent, which is on average 0.04 per cent higher than our preliminary decision estimate.

Our forecast of the overall rate of change used to derive our alternative estimate of opex is lower than Powercor's over the forecast period. Table B.1 shows Powercor's and our overall rate of change in percentage terms for the 2016–20 regulatory control period.

The differences in the forecast rate of change components are:

- our forecast of annual price growth is on average 0.91 percentage points lower than Powercor's
- our forecast of annual output growth is on average 0.03 percentage points higher than Powercor's.

We discuss the reasons for the difference between us and Powercor for the rate of change components below.

**Table B.1 Powercor and AER rate of change (per cent)**

	2016	2017	2018	2019	2020	Average
Powercor	2.67	2.84	3.15	3.15	3.17	3.00
AER	1.57	1.79	2.31	2.41	2.46	2.11
<b>Difference</b>	<b>-1.11</b>	<b>-1.05</b>	<b>-0.84</b>	<b>-0.74</b>	<b>-0.71</b>	<b>-0.89</b>

Source: AER analysis.

## B.2 Preliminary position

For our preliminary decision, we did not adopt Powercor's forecast growth in price and output in our forecast rate of change and thus our alternative estimate of opex. We have summarised our preliminary position for each rate of change component below:

- **Price growth:** for labour price growth we adopted an average of DAE's and BIS Shrapnel's forecast real growth in the wage price index (WPI) for the Victorian electricity, gas, water and waste services (utilities) industry. For non-labour price growth we forecast zero real growth. That is, we forecast non-labour prices to grow

at the same rate as CPI in nominal terms. We applied Economic Insights' benchmark opex price weightings for labour and non-labour.

- **Output growth:** we applied the weighted average forecast change in customer numbers, circuit length and ratcheted maximum demand. We based the weights of each of these outputs on Economic Insights' opex cost function analysis. We used the customer numbers and circuit length forecasts from Powercor's reset RIN and ratcheted maximum demand forecasts from AEMO.
- **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.

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

### B.3 Powercor's revised proposal

Powercor forecast the rate of change of opex based on the forecast growth in price, output and productivity. This is consistent with our own approach. However, it adopted a different approach to forecasting price growth than we have. Powercor forecast price growth as the weighted average growth in labour and non-labour prices. It forecast labour prices based on:

- the annualised wage growth rates in its current EAs for the period up until the expiry of those EAs
- the five year historical average EA wage growth rate for all privately owned electricity networks, as calculated by Frontier Economics, for the period after the expiry of its current EAs.

For non-labour prices Powercor's revised proposal introduced materials real price growth for the materials component, which it did not include in its initial proposal. For the remainder of non-labour prices it forecast no real price growth. It used an average of its actual expenditure on labour and non-labour over the three year period 2012 to 2014 to derive the weights it applied to its forecast labour and non-labour price growth rates. This is different from the weights Powercor used in its initial proposal which were based on expenditure in only 2014.

For output growth, Powercor adopted the forecasting approach we used in our preliminary decision. This is a change from its initial proposal. It adopted the customer number and circuit length forecasts in its initial proposal, which we used in our preliminary decision. It revised its peak demand forecasts.

For productivity growth Powercor forecast no growth in productivity. This is consistent with its initial proposal and our preliminary decision.

Based on this approach, Powercor's revised proposal average annual rate of change estimate was 3.00 per cent, which was a decrease from the 3.47 per cent in its initial proposal.

## B.4 Reasons for position

For the reasons we discuss below, we are not satisfied that Powercor's approach to forecasting the rate of change will provide an opex forecast that reasonably reflects the opex criteria. We have, therefore, not accepted Powercor's proposal and forecast our own estimate of the rate of change. Our estimate is lower than that proposed by Powercor due to Powercor's higher forecast price growth.

Table B.2 shows Powercor's and our overall rate of change and each rate of change component for each regulatory year of the 2016–20 regulatory control period.

**Table B.2 Powercor and AER rate of change (per cent real)<sup>108</sup>**

	2016	2017	2018	2019	2020	Average
<b>Powercor revised proposal</b>						
Price growth	1.30	1.82	1.61	1.60	1.61	1.59
Output growth	2.04	2.01	1.78	1.96	1.47	1.85
Productivity growth	–	–	–	–	–	–
<b>Overall rate of change</b>	<b>3.36</b>	<b>3.86</b>	<b>3.41</b>	<b>3.59</b>	<b>3.10</b>	<b>3.47</b>
<b>AER</b>						
Price growth	0.22	0.50	0.79	0.92	0.85	0.66
Output growth	1.33	1.26	1.26	1.34	1.53	1.34
Productivity growth	–	–	–	–	–	–
<b>Overall rate of change</b>	<b>1.56</b>	<b>1.77</b>	<b>2.07</b>	<b>2.27</b>	<b>2.39</b>	<b>2.01</b>
<b>Overall difference</b>	<b>–1.80</b>	<b>–2.10</b>	<b>–1.35</b>	<b>–1.32</b>	<b>–0.71</b>	<b>–1.46</b>

Source: AER analysis.

In estimating our rate of change, we considered Powercor's proposed forecast growth in prices, output and productivity and the method used to forecast these. The key areas of disagreement with Powercor are:

1. **Forecast labour price growth:** Powercor used a hybrid approach that used the wage increases in its EAs and historical industry average EA wage increases. We used a broader and more forward looking measure. We used the forecast change in the wage price index (WPI) for the electricity, gas, water and waste services industry (the utilities industry) as the forecast change in the labour price.

<sup>108</sup> The rate of change = (1 + price growth) × (1 + output growth) × (1 – productivity growth) – 1.

2. **Forecast non-labour price growth:** Powercor included forecast real price growth for non-labour expenses. We forecast that, overall, non-labour prices will grow at the same rate as the CPI.
3. **Input price weights:** Powercor applied a higher weighting to labour price growth, based on an average of its actual expenditure over the three year period 2012 to 2014.

We discuss each of these issues in the sections that follow. We also discuss our assessment of Powercor's output growth forecast.

While we agree with Powercor that no productivity growth should be included in the rate of change, we address submissions on this issue at the end of this appendix.

### **B.4.1 Forecast labour price growth**

Powercor forecast labour price growth using a hybrid forecasting method comprising:<sup>109</sup>

- the annualised wage growth rates in Powercor's current EAs for the period up until the expiry of those EAs
- the five year historical average EA wage growth rate for all privately owned electricity networks, as calculated by Frontier Economics, for the period after the expiry of its current EAs.

We have assessed the reasons and evidence put forward by Powercor in its revised proposal and supporting materials. We are not satisfied that Powercor's forecast of labour price growth reasonably reflects a realistic expectation of the cost inputs or the efficient costs that a prudent operator would require to achieve the opex objectives.<sup>110</sup>

There are three key reasons why we must not accept Powercor's approach to forecasting labour price growth:

1. Powercor's approach of using its current EA and an historical average of other EAs does not account for the broader labour market conditions that expert economic forecasters expect to prevail in the forecast period. We note that wage price growth for the utilities industry and the economy as a whole is currently the lowest on record.<sup>111</sup> Powercor's labour price forecasting approach does not account for the impact these conditions are likely to have on labour price growth over the forecast period. Instead, Powercor's forecasting approach assumes that, after Powercor's current EAs expire, Powercor will increase the pay to its employees on the basis of historical averages. Therefore, Powercor's approach does not reasonably reflect the opex criteria.

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<sup>109</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 90.

<sup>110</sup> NER, cl. 6.5.6(c)(3).

<sup>111</sup> ABS, *6345.0 Wage price index*, Table 9b.

2. We are concerned that adopting the wage rate increases in an individual firm's EAs would not provide effective incentives in order to promote economic efficiency through the negotiation of efficient wages.<sup>112</sup> This is because there is no benefit to a firm from negotiating lower wage rate increases in the next regulatory control period. There is no benefit because those lower wage increases will be reflected in a fall in its revenue allowance. This outcome is inconsistent with the ex ante incentive-based regulatory framework under the NER and with the national electricity objective (NEO).
3. Powercor did not use the same forecasting approach for all years of the forecast period (we call this a hybrid forecasting approach). We consider Powercor's hybrid forecasting method is likely to result in an upwardly biased total forecast of labour price growth over the regulatory control period, even assuming Powercor acted prudently and efficiently when entering into its current EAs. This is because different forecasting approaches reflect different timing assumptions. For example, if a firm has higher wages than the industry average (because it negotiated its latest EA prior to the labour market softening) then we expect, all else equal, that the wage increases in its next EA will be lower than the industry average at the time of the next EA. A compensating adjustment will be necessary to account for these timing differences.

In addition, we disagree with Powercor that its EAs are an appropriate basis for forecasting labour price growth because they, or section 50 of the *Fair Work Act 2009*, are a 'regulatory obligation or requirement'. We do not consider that we are obliged to come to a different result by reason of any decision of the Tribunal.

We set out our reasons why we are not satisfied that Powercor's forecast of labour price growth reasonably reflects the opex criteria in greater detail below.

When we are not satisfied a DNSP's total forecast opex reasonably reflects the opex criteria, the NER require that we develop our own estimate. Given we disagree with Powercor's proposed rate of change, we must estimate a forecast of labour price growth that reasonably reflects a realistic expectation of the cost inputs that a prudent and efficient operator would require.

In summary, to develop our estimate, we used a forecast of WPI growth for the Victorian utilities sector to forecast labour price growth. We are satisfied that this approach to forecasting labour price growth will result in a total forecast opex that reasonably reflects the opex criteria because:

- the utilities industry, as classified by the ABS, includes electricity distribution
- enterprise agreement wage rate growth has been similar to utilities WPI growth when both publicly and privately owned networks are considered.

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<sup>112</sup> NEL, s. 7A(3).



Furthermore, we have adopted this approach consistently and most DNSPs have also used it in their regulatory proposals, including AusNet Services, Jemena and United Energy. Similarly, Frontier Economics adopted the utilities WPI to forecast labour price growth when it forecast wholesale energy costs in the NEM for the AEMC.<sup>113</sup>

The forward looking forecasts of WPI growth for the Victorian utilities sector that we have used draw on available current and expected future market information from multiple sources, including from EAs. This is particularly important when labour market drivers have changed significantly in recent times and wage price growth, for both the economy as a whole, and the utilities industry more specifically, is at the lowest level on record.<sup>114</sup>

We consider our forecasts of labour price growth should be the average of growth in the utilities WPI as forecast by DAE and CIE. BIS Shrapnel's forecasts from December 2014 should not be included in our forecast of labour price growth because they are outdated. We have not included Frontier Economics' forecasts (as proposed by Powercor in its revised proposal) in our average because they do not contribute additional information on labour price growth that the forecasts from DAE and CIE do not already capture.

We discuss these reasons, and other issues raised by Powercor, in greater detail further below.

## **Why we cannot accept Powercor's labour price growth forecast**

As noted above, there are four key reasons why we cannot accept Powercor's forecast. The first is Powercor's approach is not forward looking and it does not consider broader labour market conditions. The second is because Powercor's approach is inconsistent with incentives to promote economic efficiency. The third is because Powercor's hybrid approach is likely to be upwardly biased. Finally, Powercor's approach relies on an incorrect interpretation of 'regulatory obligation or requirement'.

### ***Key reason 1: Powercor's proposal does not consider broader labour market conditions***

We are required to be satisfied that Powercor's forecast for labour price growth reasonably reflects the efficient and prudent costs faced by Powercor given a realistic expectation of demand forecasts and cost inputs. In our view, one important factor that will influence the labour costs faced by a prudent operator is the labour market conditions that are expected to prevail in the forecast period. We explain below why this factor is relevant. We also explain why Powercor's forecast does not take this factor into account.

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<sup>113</sup> Frontier Economics, *2015 residential electricity price trends report*, November 2015, p. 79.

<sup>114</sup> ABS, *6345.0 Wage price index*, Table 9b.



As we stated in our 2015 final decision for SA Power Networks, we consider current market conditions in other similar industries such as the mining industry and non-electricity labour in the utilities industry have an impact on electricity network labour wages.<sup>115</sup> This is consistent with previous comments by DNSPs and the views of labour price forecasters:

- In its regulatory proposal for the 2010–15 regulatory control period SA Power Networks identified other industries as having an impact on the supply and demand of its labour. For example, it identified the construction of the national broadband network as a related industry requiring similar skills.<sup>116</sup> SA Power Networks also engaged BIS Shrapnel to forecast labour cost growth. A key driver of wage growth in BIS Shrapnel's forecast was the influence of the mining and construction sectors.<sup>117</sup>
- Jacobs noted that the construction and mining industry are relevant to labour cost pressures facing Ergon Energy as many employees or contractors have the potential to work in those sectors.<sup>118</sup>
- Independent Economics noted that strong demand in the rapidly expanding mining sector has supported wages in occupations that the utilities sector employs.<sup>119</sup>
- The CIE's wage growth model takes into consideration the linkages and interactions between industries such as mining and construction.<sup>120</sup>

Powercor's method of using its current EAs combined with the historical average of EAs to forecast labour price growth does not take into account broader labour market conditions in the forecast period. We are not satisfied that Powercor's approach reasonably reflects the opex criteria. We noted in our preliminary decision that WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, were at the lowest level on record.<sup>121</sup> Since our preliminary decision WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, have fallen further.<sup>122</sup> We consider a reasonable forecast of labour prices should take into account the labour market conditions driving these changes in wage price growth.

Powercor, however, stated that the wage growth rates in the new EAs that it negotiates will not reflect general labour market conditions or conditions in the broader utilities industry. Rather, it stated, the wage growth rates will reflect the wage pressures

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<sup>115</sup> AER, SA Power Networks determination 2015–20, Attachment 7, October 2015, p. 42.

<sup>116</sup> ETSA Utilities, *ETSA Utilities regulatory proposal 2010–2015*, 1 July 2009, p. 103.

<sup>117</sup> BIS Shrapnel, *Update of outlook for wages and contract services to 2014/15: South Australia*, December 2009.

<sup>118</sup> Jacobs, *2015/20 regulatory submission Ergon Energy*, 10 October 2014, p. 33.

<sup>119</sup> Independent Economics, *Labour cost escalators for NSW, the ACT and Tasmania*, 18 February 2014, p. vi.

<sup>120</sup> CIE, *Labour price forecasts*, 17 December 2014, p. 14.

<sup>121</sup> AER, *Preliminary decision*, Attachment 7, p. 58.

<sup>122</sup> ABS, *6345.0 Wage price index*, Table 9b.

specific to electricity distributors in Victoria.<sup>123</sup> Powercor cited three reasons why EA wage growth rates 'do not mirror' the general labour market or the utilities industry:<sup>124</sup>

1. its workforce is highly specialised
2. there continues to be a demand for this skilled labour
3. the enterprise bargaining framework and the prevalence of union membership in its businesses.

It is important to note that we do not claim that wage growth rates for an efficient DNSP should 'mirror' the general labour market. Rather, we expect broader labour market conditions to have some impact on labour market outcomes for electricity distribution workers. Powercor's approach to forecasting labour price growth relies on historical averages, so it will not pick up these broader labour market impacts.

The first reason relied upon by Powercor for its wage growth rates being uninfluenced by general labour market conditions is that its workforce is highly specialised. It stated that this translates to high costs associated with recruiting trained employees and training new employees, as well as an increased desirability of retaining existing staff.<sup>125</sup> However, these factors are not unique to electricity distribution. There are many other industries that utilise specialist labour with high training costs.

Powercor did not explain how the skilled nature of its workforce results in general labour market conditions or conditions in the broader utilities industry not impacting the labour price growth it faces. The only reason for electricity networks to have efficient wage increases above other industries is due to a supply and demand imbalance for electricity labour. The specialised nature of the workforce does not, without anything else, mean that there is a supply and demand imbalance.

The second reason relied upon by Powercor for its wage growth rates being uninfluenced by general labour market conditions is that it expects continued demand for skilled labour in the 2016–20 regulatory control period. Its reasons for this included increased capex as well as ongoing maintenance.<sup>126</sup> We considered the evidence available from the Department of Employment to see if it supported this claim.

The Department of Employment reports on the demand for labour on its *Job Outlook* website.<sup>127</sup> This includes job prospects for electrical distribution trades workers for the next five years. The Department of Employment states that employment for electrical distribution trades workers rose in the past five years and rose very strongly in the past ten years. However, looking forward, it expects employment to decline to November

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<sup>123</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 81.

<sup>124</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 81–83

<sup>125</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 81.

<sup>126</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 82.

<sup>127</sup> [www.joboutlook.gov.au](http://www.joboutlook.gov.au)

2019.<sup>128</sup> The declining demand for labour does not support the use of an historic average to forecast labour price growth for the 2016–20 regulatory control period.

The third reason relied upon by Powercor for its wage growth rates being uninfluenced by general labour market conditions is the enterprise bargaining framework and the prevalence of union membership in its businesses. Powercor stated, based on advice from DLA Piper, that:<sup>129</sup>

- elements of the enterprise bargaining framework allow unions to extract favourable outcomes
- the electricity industry is highly unionised and the CEPU has a virtual monopoly over electrical employee labour supply
- given it supplies an essential service, interruptions to supply give rise to a greater risk of legal and financial consequences compared with many other industries and unions exploit this vulnerability.

DLA Piper concluded that these issues make it difficult for DNSPs to resist EA outcomes similar to previous ones.<sup>130</sup> DLA Piper provides a theoretical basis for why unionised labour may receive higher wages than non-unionised labour. DLA Piper does not provide any evidence in support of its theory.

In its 2012 edition of *Year book Australia*, the ABS reports the proportion of employees who were trade union members, by industry, as at August 2010. It shows that the level of trade union membership varied considerably across industries and that the utilities industry (37 per cent) was second only to the education and training industry (39 per cent).<sup>131</sup> Other industries with a higher than average proportion of employees who were trade union members included: public administration and safety, transport, postal and warehousing, health care and social assistance, and mining. We compared the average annual wage increases in new EAs in these industries to those negotiated for all industries and the changes in the WPI for all industries.<sup>132</sup> We found that newly negotiated wage increases broadly followed the trend in the WPI. Wage growth was not steady over time for these industries. Consequently the evidence suggests that broader labour market conditions do influence the wage increases in EAs negotiated in the most highly unionised industries.

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<sup>128</sup> Department of Employment, <http://joboutlook.gov.au/occupation.aspx?search=alpha&tab=prospects&cluster=&code=3422>, accessed 20 April 2016.

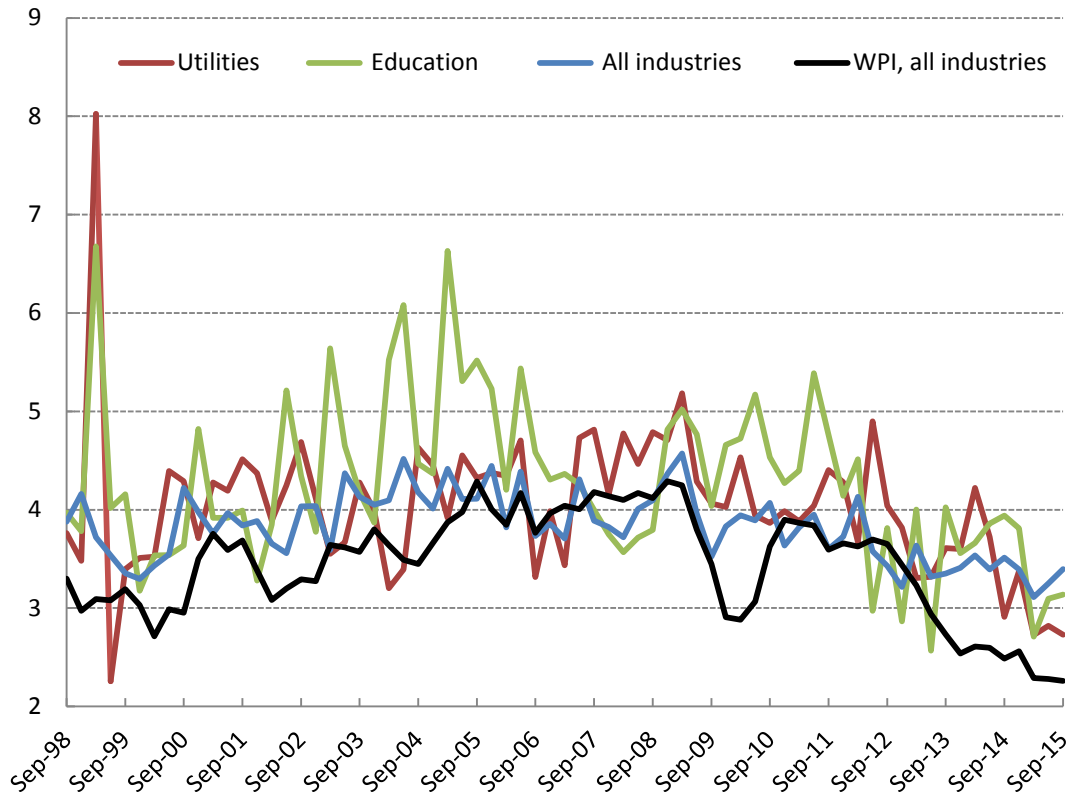
<sup>129</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 83.

<sup>130</sup> DLA Piper, *Legal opinion*, 16 December 2015, paragraph 27.

<sup>131</sup> ABS, *Year Book Australia 2012*, 24 May 2012, pp. 313–314.

<sup>132</sup> Department of Employment, *Trends in federal enterprise bargaining: September quarter 2015*, 8 December 2015.

**Figure B.1 Average annual wage increases in newly negotiated enterprise agreements (per cent)**



Source: Department of employment, *Trends in federal enterprise bargaining: September quarter 2015*, 8 December 2015; ABS, 6345.0 *Wage price index*, Table 9b.

**Enterprise agreement wage increases is not the appropriate measure of labour price growth**

Powercor stated that its EA-based forecasts are more representative of its prudent and efficient labour price growth than forecast growth in the Victorian utilities WPI.<sup>133</sup>

Because we are considering forecast labour price growth, not historic growth we must consider whether the forecasting approach used adequately accounts for the drivers of labour price growth, not whether the price measure chosen reflects the efficient wages price growth of a prudent firm historically. We consider a forward looking forecasting approach that draws on multiple sources of information on the expected changes in labour price growth drivers achieves this. A backward looking historic average forecasting approach, on the other hand, does not reasonably reflect the opex criteria.

Powercor contended that its forecasts based on historic average EA wage increases were also prudent and efficient.<sup>134</sup> It stated that Frontier Economics had demonstrated

<sup>133</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 72–80.

<sup>134</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 75–80.

that EA wage increases across the electricity network industry have been relatively stable over the past ten years—more stable than utilities WPI and Australian all industries WPI over the same period.<sup>135</sup> Figure B.1 suggests otherwise and, further, this period aligns with the mining boom in Australia. We cannot assume that the labour market conditions that were prevalent during that time will continue during the forecast period. Further, EA wage increases are only stable over time when excluding publicly owned networks from the analysis. As discussed below, when public networks are included EA wage increases are similar to the utilities WPI. We discuss below why we forecast labour price growth based on labour price growth in the broader utilities industry.

Powercor stated that in circumstances where EA wage increases have been stable, and there is no change to the drivers of this stability, there is no basis to assume that the stability will not continue.<sup>136</sup> However, we consider the drivers of stability proposed by Powercor will not necessarily deliver historic average labour price increases in the forecast period. The key drivers of wage growth are inflation, wage growth over the broader economy and labour supply and demand for the industry. All three of these suggest labour price growth over the forecast period will be lower than the historic average. Inflation over the year to December 2015 was only 1.7 per cent.<sup>137</sup> Over the same period the WPI grew only 2.1 per cent in nominal terms.<sup>138</sup> And, as noted above, the Department of Employment expects employment for electrical distribution trades workers to decline to November 2019.<sup>139</sup>

While the occupation mix will have some impact on labour supply, there is no persuasive evidence that it is a key driver. We consider that, even if the occupation mix of other utilities is different to that of electricity DNSPs, the drivers of wage growth will be similar. Consequently, we consider there is a strong basis for taking the position that the stability will not continue.

### **Powercor's proposal does not consider wage negotiations for publicly owned DNSPs**

Powercor's forecasting approach relies on the five year historical average EBA wage growth rate for all Australian privately owned electricity networks. The approach fails to account for the impact of wage negotiations for Australian publicly owned DNSPs. As we stated in our preliminary decision, different labour price outcomes between publicly and privately owned networks may occur over the short to medium term but these differences are unlikely to persist indefinitely. Different labour market conditions

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<sup>135</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 75.

<sup>136</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 75.

<sup>137</sup> ABS, 6401.0 *Consumer Price Index*, Tables 3 and 4.

<sup>138</sup> ABS, 6345.0 *Wage Price Index* Table 9b.

<sup>139</sup> Department of Employment,

<http://joboutlook.gov.au/occupation.aspx?search=alpha&tab=prospects&cluster=&code=3422>, accessed 20 April 2016.

between publicly and privately owned networks will impact the supply and demand for labour and the outcome of wage negotiations.

Frontier Economics stated that while we were correct that the gap is likely to close eventually, it considered we overstated the mobility of labour required to equalise the pay rates.<sup>140</sup> It considered it seems unrealistic to assume that worker migration would occur to such an extent to close the gap between wage rates within the 2016–20 regulatory control period for two reasons:<sup>141</sup>

1. there are no publicly-owned electricity networks in Victoria, requiring worker migration to occur between States
2. the average gap in annual pay rate increases between those employed by publicly-owned and privately-owned electricity networks, over the period 2012 to 2016, is 1.25 percentage points. That is, annual wage increases for publicly-owned networks is 1.25 percentage points lower than privately-owned networks. Frontier Economics considered it unrealistic that this sort of pay rate gap would induce mass movement of electricity network workers between states.

However, we did not state that the transfer of labour between privately and publicly owned DNSPs would equalise pay rates. Rather, we stated that different labour market conditions between publicly and privately owned networks will impact the supply and demand for labour and the outcome of wage negotiations. We maintain that using an historic average that excludes publicly owned networks does not account for any impact these labour market differences will have on future wage negotiations.

It is also not necessary for significant migration to occur to influence wage rates. Only the threat of migration is needed. It is common for labour to migrate between states. Furthermore, labour with specific skills that are not transferrable to other industries will have a greater incentive to move to other states for work because their skills will not earn them the same level of pay in other industries. We note that between 2012–13 and 2014–15 the average staffing levels reported by the New South Wales' DNSPs reduced by 1255 (or 11 per cent).<sup>142</sup> We expect some of these workers would be willing to move to Victoria.

Our view on the mobility of labour appears consistent with advice previously relied on by Powercor. Powercor included labour price growth forecasts from BIS Shrapnel in its submission for the 2011–15 regulatory control period. In discussing the outlook for utilities wages growth in Victoria, BIS Shrapnel stated that:<sup>143</sup>

... renewed growth in employment in the sector is expected in most states over the next few years, with continued strong demand for labour maintaining relatively high wage pressures within each state's utilities sector. The Victorian

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<sup>140</sup> Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 35.

<sup>141</sup> Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 35–36.

<sup>142</sup> As reported in worksheet 2.11 (labour) of the category analysis RINs.

<sup>143</sup> BIS Shrapnel, *Wages outlook for the electricity distribution sector in Victoria*, July 2010, p. 34.



utilities sector will need to offer competitive wages to retain its existing workforce and attract new recruits.

It is clear that BIS Shrapnel considered that utilities labour market conditions outside of Victoria will impact on the labour price growth faced by Powercor.

Powercor also stated that we had failed to take into account the differences in the terms and conditions of its EAs compared to publicly owned networks. It considered the wage growth rates in those EAs cannot be considered in isolation from the overall level of wages and the other benefits in the EAs. It is true that other benefits involved in wage negotiations will also affect wage outcomes. However, Powercor's forecasting approach does not take account of the terms and conditions of its EAs compared to other private DNSPs. We note that in 2015 DAE reviewed the NSW DNSPs' labour operating costs and information provided by the NSW DNSPs demonstrating similarities between EA provisions among DNSPs. It concluded that the NSW DNSPs' EAs, as a whole, were no more generous in terms of base level wages and other employee conditions than those of their peers.<sup>144</sup> That is, there were no material differences between the substantive terms and conditions of the NSW electricity distribution EAs compared to those in Victoria.

By contrast, VECUA considered that the forecast labour price growth for the Victorian DNSPs should be reducing rather than increasing.<sup>145</sup> It questioned why we forecast labour price growth for the Victorian DNSPs at twice the rate as we forecast for SA Power Networks.<sup>146</sup> We note that our forecasts of labour price growth are state specific and take into account the unique economic conditions faced. South Australia currently has the highest unemployment rate in the nation.<sup>147</sup>

VECUA also stated that industries in contraction do not face real labour price increasing drivers.<sup>148</sup> Although we broadly agree with VECUA that there is currently low wage pressure within the economy, we have forecast positive labour price growth for the 2016–20 regulatory control period. VECUA also stated that DAE expects utility sector wages growth to fall in the near term.<sup>149</sup> We included DAE's forecasts in our average of forecasts from expert economic forecasters. We note that DAE's latest forecasts,<sup>150</sup> and its initial forecasts,<sup>151</sup> included only a single year of negative real labour price growth. DAE's forecasts do not support VECUA's claim that forecast labour price growth for the Victorian DNSPs should be reducing.

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<sup>144</sup> DAE, *NSW distribution network service providers labour analysis: Final addendum to 2014 report*, 28 April 2015, pp. 12–14, 16.

<sup>145</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 68.

<sup>146</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 64.

<sup>147</sup> ABS, Catalogue 6202.0, Table 12.

<sup>148</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 65.

<sup>149</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 65.

<sup>150</sup> DAE, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 8.

<sup>151</sup> DAE, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 10.

## ***Key reason 2: Adopting a firm's revealed price growth reduces its incentive to minimise price growth***

We consider using a firm's revealed price growth would remove the incentive to minimise wage increases in EAs and adopt a more efficient input mix. Using Powercor's revealed price growth would not provide it with effective incentives in order to promote economic efficiency<sup>152</sup> and would not be in the long term interest of consumers.<sup>153</sup>

Powercor, however, proposed that we use the wage increases in its EAs until the expiry of those EAs as well as input price weights derived from its own historic expenditure.<sup>154</sup> In effect, Powercor proposed that we should use its revealed labour price growth. Powercor, however, was not consistent in how it used its revealed price change. It did not propose that we use the price increases it had negotiated in other agreements it had entered into, such as its vegetation management contract, or any other contracts.

## **Adopting the wage increase in a firm's EA reduces its incentive to minimise wage growth**

Powercor proposed that we use its EA outcomes to forecast labour price growth until the expiry of those EAs. As we stated in our preliminary decision, doing so will reduce the incentive to negotiate efficient wages. This is because there will be no benefit to a firm from negotiating lower wage rate increases in the next regulatory control period. If it did so, those lower wage increases would be reflected in its revenue allowance. DAE expressed similar concerns:<sup>155</sup>

For the AER's purposes of setting a price for electricity distribution that is in the interest of electricity consumers over the long term, EBA outcomes are useful for understanding the short term constraints that a regulated firm is experiencing.

However, if regulators simply compensate a business for its commercial negotiations with employees, then they would be effectively undercut or even remove the incentive for businesses to move to the most productive workers over time, and to the long term efficient outcome for electricity consumers.

We are also concerned that using the revealed wage increases in a firm's EA will provide it an incentive to trade off higher annual wage increases for lower non-wage entitlements. This could have no impact of the cost to the DNSP of employing labour but would increase its opex allowance.

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<sup>152</sup> NEL, s. 7A(3).

<sup>153</sup> NEL, s. 7.

<sup>154</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 66, 90.

<sup>155</sup> DAE, A response to submissions on AER's preliminary decision for a Regulatory Proposal, 11 September 2015, p. 3.



For these reasons NSPs do not have strong commercial incentives to negotiate lower wage increases in the following regulatory control period.

VECUA appear to agree that we should not adopt the wage rate increases in an individual firm's EA as our labour price growth forecast. It stated that the Victorian DNSPs' EAs are delivering wages well above the efficient level. It stated that our preliminary determinations would allow the Victorian DNSPs to continue to treat inefficient EA outcomes as a 'pass through'.<sup>156</sup> We agree that it would be inappropriate to treat the wage price increases in an EA as a pass through, because it would reduce the incentive to negotiate efficient wages. However, we note that we did not use the wage rate increases in Powercor's EAs as our labour price growth forecast for the years up until the expiry of those agreements

Powercor also stated that the 'stickiness' experienced in EA wage growth rates reflects a range of factors that will continue irrespective of the approach we take to forecasting labour price growth. It stated that we cannot expect our decision to either increase or decrease the wage growth rates included in future EAs. This statement is inconsistent with 'the background of the highly unionised nature of the electricity distribution industry' claimed by Powercor because it is unlikely that unions would accept wage rate increases lower than the labour price growth forecasts provided in our determination.<sup>157</sup> Consequently we consider it is likely that the labour price growth forecasts provided in our determination will provide a floor for wage negotiations in the 2016–20 regulatory control period.

### **Broader incentive effects of using a firm's revealed price growth**

The incentive effects of using a firm's revealed price growth go beyond reducing the incentives to negotiate lower wage increases in the following regulatory control period. Analysis previously undertaken by Mr Jeff Balchin for PWC, and submitted to the AER by Electranet, shows that:<sup>158</sup>

...it is inappropriate and inconsistent with the incentive framework for the assumed trend or trajectory after the base year to be based upon the observed performance in the preceding regulatory period.

How we use revealed opex when we forecast total opex influences the incentive to reduce opex. If we were to use a firm's revealed price growth, then the lower a firm's actual price growth, the lower its forecast price growth for subsequent periods, all else equal. However, if we do not base our forecast price growth on the firm's revealed price growth, then its revealed price growth does not influence its opex forecast. Consequently using a firm's revealed price growth reduces its incentive to reduce price growth.

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<sup>156</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 65.

<sup>157</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 70.

<sup>158</sup> PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013, p. 6.

Mr Balchin demonstrated this in his report for Electranet. He shows that if factoring a firm's revealed efficiency gains when setting base opex and determining the trend, the reward from an improvement in opex is substantially diminished (and, similarly, the penalty from a decline in opex would be reduced).<sup>159</sup> By applying a *benchmark* rate of change to the firm's revealed level of opex and applying the EBSS, the firm is able to retain the efficiency gains it makes for an additional five years after making them. Thus using a *benchmark* rate of change allows the firm to retain around 30 per cent of the efficiency gain. However if we were to use the firm's *revealed* rate of change, when it makes efficiency gains its opex for the following period would be reduced by the lower revealed rate of change as well as the lower revealed base opex. As a result, the firm would retain less than 30 per cent of the efficiency gains. Consequently, the lower rewards for the firm would almost entirely eliminate the incentives ordinarily provided by the regulatory framework.<sup>160</sup> This would not be in the long term interest of consumers.

Given these incentive effects, we consider forecast price growth should be a benchmark, so as to provide firms effective incentives in order to promote economic efficiency.<sup>161</sup> Using a benchmark forecast of price growth ensures the firm's revealed price growth does not impact forecast opex (beyond the impact on base opex) and diminishes its incentive to reduce price growth.

### **Other concerns with using revealed price growth to forecast**

We have a number of other concerns with using revealed labour price growth to forecast labour price growth.

Firstly, we disagree with Powercor's submission that by accepting its base opex as efficient, we have accepted its EAs are efficient. When we assessed Powercor's base year opex, we were satisfied that at the total level, it reasonably reflected the opex criteria. However, in doing so we did not make any judgment about the various components that comprise base opex. This is unnecessary when benchmarking demonstrates that, overall, Powercor is operating relatively efficiently compared it is peers. Importantly, the NER do not require us to examine components of opex.<sup>162</sup>

Therefore, it does not follow that the wages in Powercor's current EAs are necessarily efficient even though we are satisfied that, overall, Powercor's base opex reasonably reflects the opex criteria. Many different expenditure items within Powercor's base opex may be higher or lower than originally forecast, but overall, they offset each other. This is a fundamental tenet of the base-step-trend approach that we consider—and Powercor agrees—is an appropriate means of forecasting total opex.

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<sup>159</sup> PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013, p. 7.

<sup>160</sup> PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013, pp. 7–8.

<sup>161</sup> NEL, s. 7A(3).

<sup>162</sup> NER, cl 6.5.6(c), 6.12.1(4).

In any event, Powercor's two existing EAs commenced in 2014. One includes two bi-annual wage increases in 2014, on 6 May and on 1 August. The second EA has a single wage increase in 2014 on 1 July. Consequently Powercor's existing EAs had only a small impact on Powercor's expenditure in the base year. Therefore, we do not agree that finding Powercor's base year opex to be reasonably efficient necessarily means Powercor's existing EAs are also efficient.

Second, we do not consider that a finding that a firm's revealed base opex is reasonably efficient necessarily means that its revealed price growth will produce a total opex forecast consistent with the opex criteria. Under our opex forecasting approach we have tested whether the absolute level of opex in the base year reasonably reflects the opex criteria. The testing of the proposed price growth is a separate process.

Third, the operating conditions prevalent during the historic period may not be prevalent during the forecast period. Consequently, even though a firm's price growth during the historic period may have been efficient at that time, that does not mean the same price growth would be efficient for the forecast period. For example, assume there was strong demand for labour during the historic period that resulted in strong labour price growth. However, if the demand for labour weakens, and supply increases, then we expect lower price growth during the forecast period. Ignoring market conditions for the forecast period would not result in a forecast that represents a realistic expectation of the cost inputs required to achieve the opex objectives.

Finally, it is important to recognise the interaction between the three rate of change components (output growth, input price growth and productivity). An individual firm may have been able to achieve greater productivity growth than the benchmark but, in doing so, incurred price growth above the benchmark rate. Consequently using the firm's revealed price growth combined with a benchmark productivity growth, would overstate the rate of change of a prudent and efficient firm.

### **The incentive impacts of using historic average industry wide wage increases**

A separate issue is the incentive impacts of relying upon historic average wage increases to forecast future wage increases after the expiry of the current EAs.

Frontier Economics stated that a scheme based on the average EA wage increases would have the desirable property of driving efficiencies over time because:<sup>163</sup>

- no single network service provider could materially influence the growth rates
- once growth rates are set, every network service provider has a strong profit incentive to secure lower EA outcomes than the allowances set
- every network service provider would have similar incentives to beat allowances

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<sup>163</sup> Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, pp. 23–24.

- even if only a proportion of service providers achieve savings, the average would decline and the average would be expected to fall over time.

We agree that using an industry average benchmark provides these incentive properties. However, as we stated above, we consider it likely that the labour price growth forecasts in our determination will provide a floor for future wage negotiations. Forecasting wage rate increase based on a five year historic average will entrench those wage increases making it difficult to negotiate efficient wage increases consistent with the broader economic conditions. This will be particularly true if labour is highly unionised, as claimed by Powercor. Thus using a backward looking labour price growth forecast, rather than a forward looking one, will not be in the long term interest of consumers.

### ***Key reason 3: Powercor's hybrid forecasting method is conceptually flawed***

Consistent with our preliminary decision, we do not consider Powercor's approach of using more than one method to forecast labour price growth over a single regulatory control period (a hybrid approach) is appropriate. Powercor forecast labour price growth on the basis of two different approaches. For the period up until the expiry of Powercor's current EAs, Powercor based its forecast on the annualised wage growth rates in those EAs. For the period after the expiry of Powercor's current EAs, Powercor based its forecast on the five year historical average EA wage growth rate for all privately owned electricity networks as calculated by Frontier Economics.

Even if Powercor acted prudently and efficiently when it entered into its current EAs, this hybrid approach is conceptually flawed. It risks producing a biased forecast of labour price growth over the entire period because of differing prevailing market conditions at the time EAs were entered into. Absent a compensating adjustment to account for these timing differences, a hybrid approach will not produce a forecast that reasonably reflects the opex criteria. It is for this reason we have used a consistent forecasting approach to forecast labour price growth over the entire forecast period.

As we explained in our preliminary decision, wage increases in an individual EA will often deviate from the industry average as time goes on. One reason for this is that the market conditions and expectations, and the existing wage levels, prevalent at the time an agreement is made will drive the wage increases in that agreement. These conditions will be different than those that exist when other firms negotiate their agreements at different times. For example, when labour market conditions are softening the wage increases in an agreement made a year ago will likely be higher, all else equal, than an agreement made today. Thus, different firms may have negotiated different wage increases for the same year because they negotiated them at different points in time.<sup>164</sup>

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<sup>164</sup> AER, *Preliminary decision*, Attachment 7, pp. 56–57.

Consequently, using an individual EA to forecast labour price growth at the start of the forecast period and another forecasting approach for the remainder is likely to produce a biased forecast. This is because the two different forecasting approaches reflect different timing assumptions, and consequently different starting wage rates. For example, if a firm has higher wages than the industry average (because it negotiated its latest agreement prior to the labour market softening) then we would expect, all else equal, that the wage increases in its next EA would be lower than the industry average. This is because its wages rates at the time it negotiates its next EA would be higher than the industry average.

As we note above, DAE reviewed the NSW DNSPs' labour operating costs and concluded that the NSW DNSPs' EAs, as a whole, were no more generous than those of their peers.<sup>165</sup> That is, there were no material differences between the substantive terms and conditions of the NSW electricity distribution EAs compared to those in Victoria. Since this wage review, the wage increases in Powercor's EAs have been higher than those in the Victorian utilities industry and higher than the NSW and Queensland DNSPs. Consequently it is likely that adopting Powercor's hybrid forecasting approach will yield an upwardly biased forecast of labour price growth over the entire forecast period.

For Powercor's hybrid forecast not be to upwardly biased, its wage rates would need to be lower than the industry average in 2014. None of the evidence available to us suggests this is the case.

Consequently, applying a forecast of industry average wage increases for the remainder of the period does not reasonably reflect a realistic expectation of the cost inputs or the efficient costs a prudent operator would require to achieve the opex objectives.<sup>166</sup> If we were to adopt a firm's own EAs for the initial years of the forecast period we would need to adjust the forecast for the remaining years to account for the different timing assumptions.

An adjustment would be necessary even if the forecasting approach for the latter part of the regulatory period was based on expected prevailing forecast conditions in the labour market. Powercor's approach, however, is even less appropriate because it is relying on historical averages, which as we explained above, do not adequately account for broader labour market implications.

Powercor, in its revised regulatory proposal, considered that our description of its forecasting method as a 'hybrid forecasting method' was a mischaracterisation of the forecasting approach it adopted. Powercor stated that the outcomes of its actual EAs are known and thus do not need to be forecast. It stated it only needed forecasts for the period following the cessation of those agreements. Accordingly, it considered it

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<sup>165</sup> DAE, *NSW distribution network service providers labour analysis: Final addendum to 2014 report*, 28 April 2015, pp. 12–14, 16.

<sup>166</sup> AER, *Preliminary decision*, Attachment 7, p. 57.

only adopted a single forecasting method for the 2016–20 regulatory control period.<sup>167</sup> However, Powercor's submissions do not address the concerns we raised about hybrid forecasting approaches in our preliminary decision. Regardless of whether labour price change for the first year of the forecast period is considered forecast or actual price growth, our concerns remain valid.

Powercor further stated that:<sup>168</sup>

In any event, it would be absurd to disregard the known outcomes of the actual EBAs and to instead adopt a less accurate forecast on the footing that this would avoid a hybrid forecasting method.

Again this statement does not address our concerns with a hybrid forecasting approach.

Even if we were satisfied that Powercor's EAs were prudent and efficient, Powercor's labour price forecasting approach would trade off more accurate forecasts of labour price growth for the period of its existing EAs for an upwardly biased forecast over the entire forecast period.<sup>169</sup> For the reasons explained above, Powercor's hybrid forecast is upwardly biased because the wage increases in its EAs are higher than the wage increases forecast for the Victorian electricity distribution industry as a whole for 2016. Consequently it will not need to offer wage increases as high as the rest of the market for electricity distribution labour for its wages to be competitive for the remainder of the forecast period.

This is true regardless of whether we use our WPI forecasting method or Frontier Economics' historic average forecasting method. This does not necessarily mean that Powercor's EAs are inefficient. Rather it is because labour market conditions have softened since Powercor negotiated those agreements.

Consequently, we are not satisfied that Powercor's approach of using its existing EAs to forecast labour price growth at the start of the forecast period and a second forecasting approach based on historical averages for the remainder would produce an opex forecast that reasonably reflects the opex criteria over the forecast period.

Powercor noted that we have, in decisions for AusNet Services' transmission network and Powerlink, used the wage rate increases in EAs.<sup>170</sup> We did not consider the problems arising from hybrid forecasting approaches in reaching these decisions. In other decisions, such as our decision for Ergon Energy in 2010, we did not use the wage rate increases in EAs. Ergon Energy sought merits review of this decision and the Australian Competition Tribunal adopted labour price growth rates based on Ergon Energy's existing EAs until the expiry of those agreements and thereafter labour price

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<sup>167</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 80.

<sup>168</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 80.

<sup>169</sup> AER, *Preliminary decision*, Attachment 7, pp. 56–57.

<sup>170</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 80.



growth rates based on forecasts prepared by an economic forecaster.<sup>171</sup> However, we had not considered the problems arising from hybrid forecasting approaches at that time. Nor is there any evidence that the Tribunal considered the problems arising from hybrid forecasting methods. We should not now ignore this issue simply because we, and the Australian Competition Tribunal, did not consider it in previous decisions.

Powercor also stated that the stability of EA outcomes over time means that adopting a hybrid forecasting approach is not significantly different from adopting a single forecasting approach.<sup>172</sup> Powercor is correct that the bias introduced by adopting a hybrid forecasting approach is lower the more constant wages are over time. If wage growth was perfectly stable then using a hybrid forecasting approach would result in the same outcome as using a single forecasting approach. This is because the labour price forecast will be the same for the initial years regardless of the forecasting approach adopted.

However, Powercor's approach does not reasonably reflect the opex criteria because we are not satisfied, based on the evidence before us, that the labour market will be stable in the forecast period. Our approach of adopting a single forecasting method, on the other hand, will reasonably reflect a realistic expectation of the labour price growth faced by a prudent and efficient firm in the forecast period because it is unbiased regardless of whether wage growth is flat or not.

***Compliance with an enterprise agreement is not a regulatory obligation or requirement or otherwise required by the NER***

Powercor, in its revised regulatory proposal, submitted that the AER is required to compensate it for the costs of complying with its EAs - in other words for all of its employment costs if those costs are required to be paid under its negotiated EAs. Clause 6.5.6(3)(c) requires the AER to accept a DNSP's forecast of operating expenditure if it is satisfied that the total forecast "reasonably reflects" the three opex criteria. One of the criteria is the "costs that a prudent operator would require to achieve the operating expenditure objectives." One of those objectives is to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services": clause 6.5.6(a)(2).

Powercor submitted that compliance with its EAs amounts to compliance with 'regulatory obligations or requirements' as defined in the NEL because:<sup>173</sup>

- the Commonwealth is a 'participating jurisdiction' so the *Fair Work Act 2009* (Cth) (FW Act) is 'an Act of a participating jurisdiction';
- section 50 of the FW Act prohibits contravention of the terms of an EA so it is an 'obligation or requirement' under the FW Act, or, alternatively, the EAs themselves are 'obligations or requirements' under the FW Act; and

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<sup>171</sup> Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No. 3) [2010] ACompT 11.

<sup>172</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 81.

<sup>173</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 70.

- EAs materially affect the provision of electricity network services.

Powercor further submitted, in a late submission, that the recent consideration of EAs by the Australian Competition Tribunal supports its position that its expenditure forecasts must allow for compliance with its EAs. Powercor submitted that even if EAs are not 'regulatory obligations or requirements', they may reasonably be regarded as required to achieve the clause 6.5.6(a)(4) opex objective (to maintain the safety of the distribution system) and reasonably reflecting the clause 6.5.6(c)(3) opex criterion (a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives).<sup>174</sup>

In our view, nothing in the NEL or NER obliges the AER to compensate DNSPs for the costs of paying wages under its negotiated EAs.

### **EAs and section 50 of the FW Act are not regulatory obligations or requirements**

Powercor relies on the definition of 'regulatory obligation or requirement' in section 2D(1)(b)(v) of the NEL:

an Act of "a participating jurisdiction", or "any instrument made or issued under or for the purposes of that Act"...that "materially affects the provision, by a regulated network service provider, of electricity network services" that are the subject of a distribution determination or transmission determination. [quotes added]

Clause 6.5.6(a) of the NER requires a DNSP to include, in its building block proposal, the total forecast opex the DNSP considers is required in order to:

comply with all applicable regulatory obligation or requirements "associated with the provision of standard control services".

We have examined Powercor's submissions in the context of each of the quoted relevant phrases. Powercor's argument will not succeed unless section 50 of the FW Act satisfies, or its EAs satisfy, every element of these definitions.

#### A participating jurisdiction

In response to Powercor's first point, we observe that the Commonwealth is a participating jurisdiction through the application of the NEL to offshore adjacent areas.<sup>175</sup> This enables uniform application of the electricity legislation but ensures the

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<sup>174</sup> Powercor, Submission on implications of recent Australian Competition Tribunal decisions, 18 April 2016.

<sup>175</sup> *Australian Energy Market Act 2004*, s. 6; Second reading speech, National Electricity (South Australia) (New National Electricity Law—Miscellaneous Amendments) Amendment Bill 2007, Parliament of South Australia, Hansard of the House of Assembly, 27 September 2007, p. 963; Second reading speech, National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, Parliament of South Australia, Hansard of the House of Assembly, 9 February 2005, p. 1451.



jurisdiction of the Commonwealth does not unnecessarily overlap with State or Territory jurisdictions.<sup>176</sup> Section 2D of the NEL should be read in this context.

We accept that section 50 of the FW Act is an obligation under an "Act of a participating jurisdiction." However, for the reason set out below, we do not accept that section 50 of the FW Act materially affects the provision of network services.

#### Any instrument made or issued under or for the purposes of that Act

Powercor argued, in the alternative, that an EA is an "instrument made or issued under or for the purposes of" the FW Act.<sup>177</sup>

We note that an EA is an agreement entered into by the DNSP exercising its business discretion. That is, it is a voluntary commercial agreement. Although an EA is regulated by the FW Act, it is not an instrument 'made' for the purposes of the FW Act. An EA is 'made' when agreement is reached between an employer and a majority of employees.<sup>178</sup>

It is more appropriate to describe the FW Act as regulating EAs (including in relation to their enforcement), in much the same way that the Family Law Act 1975 (Cth) regulates financial agreements (Part VIIIA), the Franchising Code of Conduct regulates franchise agreements and the National Consumer Credit Protection Act 2009 (Cth) regulates consumer credit (Schedule 1). All of these agreements are made by the parties, but regulated by an Act. It is wrong to conflate these two concepts; an agreement made between parties is not made or issued under or for the purposes of an Act simply because it is regulated by the Act.

#### Materially affects the provision...of electricity network services

In response to Powercor's third point, we do not agree that an EA or section 50 of the FW Act materially affects the provision of network services. An EA is simply a type of an employment agreement. Section 50 of the FW Act prohibits contravening an EA.

However, there is no necessary connection between the terms of an EA or section 50 of the FW Act and the provision of network services by a DNSP. The FW Act is an Act of general application. Its purpose is to govern workplace relations between enterprises and their employees, not how a DNSP must provide electricity network services. Labour costs may be higher or lower under an EA and other employment terms and conditions may differ without any impact on the provision of electricity network services.

Even if a bargain struck between a DNSP and employees did materially affect the provision of network services (which is denied), the EA or section 50 of the FW Act is

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<sup>176</sup> The Parliament of the Commonwealth of Australia, House of Representatives, Australian Energy Market Bill 2004, Explanatory Memorandum, pp. 4-6.

<sup>177</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 70-71.

<sup>178</sup> *Fair Work Act 2009* (Cth), s. 182.

not the kind of "obligation or requirement" intended to be covered by section 2D of the NEL. A DNSP can choose to use EAs as a means of employing staff to operate its network. However, there is no externally imposed obligation on a DNSP to use a particular EA. An EA merely records the bargain struck between a DNSP and its employees. It is an agreement voluntarily entered into and negotiated by the DNSP. Section 50 ensures that the agreement is enforceable under the FW Act. If anything materially affects the provision of network services (which is denied), it is the DNSP's own decision to enter into the agreement.

#### Associated with the provision of standard control services

The relevant opex objective is to "comply with all applicable regulatory obligations or requirements associated with the provision of standard control services". Even if section 50 of the FW Act or EAs are "regulatory obligations or requirements"(which is denied) they must also satisfy the criterion that they be associated with the provision of standard control services.

For similar reasons as stated above, an obligation under an EA or the FW Act is not a regulatory obligation or requirement 'associated with the provision of standard control services'. The obligations under an EA or the FW Act have no particular association with the provision of standard control services. With respect to the FW Act, it is of general application. With respect to EAs, the EA, as an obligation, has no association with standard control services. The association is with the enterprise, the DNSP, that entered into the agreement.

#### **Enterprise agreements and the opex objectives and criteria**

We do not consider the compliance with EAs is a part of the opex objectives. As discussed above, the obligation to comply with EAs is not a regulatory obligation or requirement associated with the provision of standard control services for the purposes of clause 6.5.6(a)(3). EAs may be a means of engaging labour in order to achieve the opex objective of maintaining safety under clause 6.5.6(a)(4). However, the safety objective or other opex objectives do not mandate specific EAs or specific employee numbers. Rather, costs associated with EAs need to be assessed against the opex criteria.

We cannot automatically accept costs associated with EAs as a part of the expenditure allowance. For those costs to be included in the expenditure allowance, we must be satisfied that the total opex for the entire 2016–20 regulatory control period reasonably reflects a realistic expectation of cost inputs required to achieve the opex objectives, and the efficient costs that a prudent operator would require to achieve the opex objectives.

As discussed above, we consider Powercor's hybrid forecasting approach does not produce a realistic forecast of labour costs for the entire 2016–20 regulatory control period. It is backward looking and does not take account of the broader market conditions expected to prevail during the period. Therefore, Powercor's forecast does not reasonably reflect a realistic expectation of cost inputs required to achieve the opex objectives. We also consider that Powercor's forecast would not provide it with

effective incentives in order to promote economic efficiency<sup>179</sup> and would not be in the long term interest of consumers.<sup>180</sup>

## Determining our substitute forecast

When we are not satisfied a DNSP's total forecast opex reasonably reflects the opex criteria, the NER require that we develop our own estimate. Given we disagree with Powercor's proposed rate of change, we must estimate a forecast of labour price growth that reasonably reflects a realistic expectation of the cost inputs that a prudent and efficient operator would require.

### *Labour price growth based on growth in the wider utilities industry is the appropriate measure*

Consistent with our preliminary decision we are satisfied that forecast growth in the WPI for the Victorian utilities industry reasonably reflects a realistic expectation of the labour price growth faced by a prudent and efficient service provider in the 2016–20 regulatory control period. This is our standard approach to forecasting labour price growth. Many DNSPs, including AusNet Services, Jemena and United Energy, also use forecast growth in the utilities WPI to forecast labour price growth in their regulatory proposals.

Similarly, we also note that the AEMC engaged Frontier Economics to forecast wholesale energy costs in the NEM for the 2015 *Residential electricity price trends* report.<sup>181</sup> To do so, Frontier Economics escalated labour costs based on the average real increase in the labour price index for workers in the utilities industries.<sup>182</sup> This is consistent with our approach to forecasting labour price growth.

We are satisfied that the forecast growth in the WPI for the utilities industry reasonably reflects the labour price increases that a prudent and efficient DNSP would face because:

- the utilities industry, as classified by the ABS, includes electricity distribution
- enterprise agreement wage rate growth has been similar to utilities WPI growth when both publicly and privately owned networks are considered.

The forward looking forecasts of WPI growth for the Victorian utilities sector that we have used draw on available current market information from multiple sources, including from EAs. This is particularly important when labour drivers have changed significantly in recent times and wage price growth, for both the economy as a whole, and the utilities industry more specifically, is at the lowest level on record.<sup>183</sup>

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<sup>179</sup> NEL, s. 7A(3).

<sup>180</sup> NEL, s. 7.

<sup>181</sup> Frontier Economics, *2015 residential electricity price trends report*, November 2015, p. 7.

<sup>182</sup> Frontier Economics, *2015 residential electricity price trends report*, November 2015, p. 79.

<sup>183</sup> ABS, *6345.0 Wage price index*, Table 9b.

DAE considered that electricity labour is a large component of the utilities sector and therefore it has a notable impact on the WPI series.<sup>184</sup> It also considered that a difference between electricity labour and non-electricity labour, if true, is neutral as to wage implications. It may point to wage pressures being either higher or lower than the utilities industry more generally.<sup>185</sup>

Powercor, however, stated that growth in the utilities WPI was not reflective of the labour price growth it faces.<sup>186</sup> Powercor is correct that it is not possible to determine the weight given to electricity distributors within the utilities WPI. The important question, however, is not whether the composition of the utilities labour force is similar to the electricity distribution labour force, but whether the efficient labour price growth of a prudent firm is similar to labour price growth for the utilities industry.

Frontier Economics have shown that, historically, the wage increases in EAs for privately owned networks have differed from growth in the Australian utilities WPI. However, they have not considered why the drivers of wage growth were different for privately owned networks and whether it is reasonable to assume that these differences will persist. In our view those differences will not persist given expected market conditions. As discussed above, when publicly owned networks are included, enterprise agreement wage rate growth has been similar to utilities WPI growth. We also discuss above the impact of broader labour market conditions on the wages of a prudent and efficient benchmark electricity distribution network. This includes the influence that wage negotiations of the publicly owned electricity distribution networks will have on the wage negotiation of a prudent and efficient benchmark firm.

Powercor also noted that analysis conducted by Frontier Economics suggested the occupation mix of utilities businesses other than electricity distributors is generally very different to the labour mix of electricity distributors.<sup>187</sup> Frontier Economics concludes that the utilities WPI is very unlikely to be representative of the labour costs of electricity distributors.<sup>188</sup> We agree that a different occupation mix could lead to absolute wage levels, as reflected by the WPI, not being reflective. However, it does not necessarily follow that a different occupation mix will result in wages for electricity distribution workers growing at a different rate than workers in the wider utilities industry. The key drivers of wage growth are inflation, wage growth over the broader economy and labour supply and demand for the industry. All three of these suggest labour price growth over the forecast period will be lower than the historic average. While the occupation mix will have some impact on labour supply, there is no persuasive evidence that it is a key driver. We consider that, even if the occupation mix

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<sup>184</sup> DAE, *A response to submissions on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 11.

<sup>185</sup> DAE, *A response to submissions on AER's preliminary decision for a regulatory proposal*, 11 September 2015, p. 11.

<sup>186</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 76.

<sup>187</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 78.

<sup>188</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 78.

of other utilities is different to that of electricity DNSPs, the drivers of wage growth will be similar.

We also note that Powercor stated in its regulatory proposal that consultants' utilities WPI forecasts have tended to be lower than the industry average EA wage increases.<sup>189</sup> We stated in our preliminary decision, however, that Australian utilities WPI wage increases are comparable to the EAs for electricity network service providers when public sector EAs are included.<sup>190</sup> Powercor stated that analysis by Frontier Economics indicates that there is a divergence between EA rates and the utilities WPI, even if the EA outcomes of publicly-owned networks are included in the analysis.

Powercor noted that Frontier Economics stated in a report for SA Power Networks that the average EA wage growth rate in 2013-2014 (measured on a financial year basis) for all electricity networks in Australia was 3.6 per cent, compared to the rate of change in the national EGWW WPI over that period of 3.2 per cent.<sup>191</sup> However, Frontier Economics calculated the average EA wage growth rate using a simple average. It failed to account for the fact that the publicly owned networks are larger than the privately owned networks. If it had weighted the EA wage increases to reflect the size of the networks, this gap would be significantly narrower.

### **Our approach is consistent with our expenditure forecasting principles**

Consistent with our preliminary decision we consider our forecast of labour price growth is appropriate and reasonably reflects the opex criteria, having regard to the following principles for the assessment of forecasting methods, which are set out in *Expenditure forecast assessment guideline*:

- valid
- accurate and reliable
- robust
- transparent
- parsimonious
- fit for purpose.

We agree with Powercor that the labour price forecasting method it adopted is simpler (more parsimonious) and more transparent than the forecasting methods adopted by DAE and CIE. However, the consideration of the assessment principles is a matter of balance as they may be competing. We consider that Powercor's forecasts of labour price growth are simpler and more transparent because it has used an oversimplified forecasting approach that fails to account for important drivers of labour price growth.

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<sup>189</sup> Powercor, *Regulatory proposal*, 30 April 2015, p. 80.

<sup>190</sup> AER, *Preliminary decision*, Attachment 7, p. 60.

<sup>191</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 84.

Consequently, parsimony (or simplicity) and transparency have come at the expense of validity, accuracy, robustness and fitness for purpose. Forecasting methods based on historical averages cannot account for changes in labour market conditions that will prevail in the forecast period. Having regard to these principles, therefore, we consider Powercor's approach is not appropriate and does not reasonably reflect the opex criteria.

We also do not share Powercor's concerns about the lack of transparency of the forecasting techniques used by expert economic consultants who forecast WPI growth. While reviewing the forecasting techniques used to forecast WPI growth will provide some insight into the robustness of a forecast the ultimate test is to compare the forecast against actual WPI growth when it eventuates. Having previously considered the historic forecasting performance of WPI forecasts we are satisfied that our averaging approach produces robust labour price growth forecasts.<sup>192</sup>

We also note that Powercor's transparency concerns apply equally to its own proposal given it used WPI growth forecasts from CIE to forecast capex contracts price growth and forecasts from Jacobs to forecast materials price growth for both capex and opex.

### ***Which forecasts should we include in our average?***

Where a consultant has previously forecast labour prices, we consider an averaging approach that takes into account the consultant's forecasting history, if available, to be the best method for forecasting labour price growth. We, and DAE, have previously undertaken analysis that found that DAE under-forecast utilities labour price growth at the national level. The analysis also found that BIS Shrapnel over-forecast price growth and by a greater margin.<sup>193</sup> For our preliminary decision we used an average of the WPI growth rates forecast by DAE and BIS Shrapnel.

However, none of the Victorian DNSPs provided updated WPI forecasts from BIS Shrapnel. Consequently the only forecasts we have from BIS Shrapnel were those it produced in November 2014.

As a result, we considered alternative sources of WPI forecasts. CitiPower, Powercor and AusNet Services all included WPI growth forecasts from CIE with their revised regulatory proposals, as they did with their initial proposal. In our preliminary decision for AusNet Services we raised a number of concerns with CIE's WPI growth forecasts. Specifically, we stated that CIE WPI growth forecasts looked inconsistent with the prevailing labour market conditions in that they peaked in 2016 and remained above the historic average over the entire forecast period.<sup>194</sup> However CIE has addressed these concerns in its revised forecasts. We compare the Victorian utilities WPI forecasts from all three forecasters in Table B.3.

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<sup>192</sup> AER, *Powerlink Final decision*, p. 54, April 2012.

<sup>193</sup> AER, *Powerlink Final decision*, p. 54, April 2012.

<sup>194</sup> AER, *Preliminary decision: AusNet Services*, Attachment 7, October 2015, p. 56



**Table B.3 Forecast annual WPI growth, Victoria, EGWWS (per cent)**

	2016	2017	2018	2019	2020	Average
BIS Shrapnel (November 2014)	0.9	1.3	1.8	2.1	1.8	1.6
CIE (November 2015)	0.7	1.0	1.1	1.0	1.0	0.9
DAE (February 2016)	0.1	-0.2	0.5	0.9	1.1	0.5

Source: DAE, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 8; CIE, *Labour price forecasts*, 23 November 2015, p.76; BIS Shrapnel, *Real labour and material cost escalation forecasts to 2020*, November 2014, p. ii.

The forecast Victorian utilities WPI growth rates from BIS Shrapnel are higher on average than the historic average rate at the national level of 1.2 per cent per annum.<sup>195</sup> By contrast, the forecast utilities WPI growth rates from both DAE and CIE are lower, on average, than the historic average rate. We noted in our preliminary decision that WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, were at their lowest level on record.<sup>196</sup> WPI growth rates, both at the Australian all industries level and for the utilities industry more specifically, have since fallen further.<sup>197</sup>

We note that CIE's revised forecasts are significantly lower than its initial forecasts from December 2014. Its revised average annual WPI growth forecasts are 0.8 per cent lower. CIE stated that the primary driver of this reduction was a downgrade to its forecast GDP growth and an upgrade to its forecast labour supply growth.<sup>198</sup> Consequently it is clear that CIE considered changes in economic conditions between December 2014, when it released its initial forecasts, and November 2015, when it released its revised forecasts, have had a significant impact on wage growth expectations. BIS Shrapnel's December 2014 forecasts do not account for these changed conditions. Consequently we consider BIS Shrapnel's outdated forecasts should not be included in our average.

Powercor also stated that we had not placed any weight on its EA based forecasts. It considered that, in doing so, we had disregarded that EAs provide the most direct indication of labour costs faced by distributors.<sup>199</sup> Frontier Economics stated that, in the event we do not apply EA based forecasts as the measure of labour price growth, we should recognise that those forecasts contribute valuable information on labour price growth. It recommended that we should assign at least as much weight to EA based forecasts as we do to utilities WPI growth forecasts.<sup>200</sup>

<sup>195</sup> ABS, *6345.0 Wage price index* Table 9b.

ABS, *6401.0 Consumer price index*, Tables 3 and 4.

<sup>196</sup> AER, Preliminary decision, Attachment 7, p. 58.

<sup>197</sup> ABS, *6345.0 Wage price index*, Table 9b.

<sup>198</sup> CIE, *Labour price forecasts*, 23 November 2015, p. 25.

<sup>199</sup> Powercor, Revised regulatory proposal, p. 89.

<sup>200</sup> Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 39–40.

However, it is incorrect to say that we disregarded EAs. DAE use EA wage growth as an input into its forecasts, particularly in the short term.<sup>201</sup> As noted by DAE, the Department of Employment provides quarterly information on EAs for each industry in its *Trends in federal enterprise bargaining* reports.<sup>202</sup> The 'all current' EAs series depicts wage growth under all agreements current during the quarter. This series broadly follows the WPI series. The 'new in quarter' EAs series shows annual wage growth under any new agreements commencing in the quarter. Thus, this series predicts future trends in the 'all current' agreements series. Recent agreements lodged with the Department of Employment indicate that wage growth is trending back down towards WPI growth.<sup>203</sup>

Consequently, we agree that EAs do provide valuable information on labour price growth. However, we disagree that including the Frontier Economics forecasts in our average would contribute additional information on labour price growth that is not already captured in the forecasts we have from expert economic forecasts. Consequently, we have not included the Frontier Economics forecasts in our average forecast of labour price growth.

## B.4.2 Forecast non-labour price growth

As noted above we have forecast real non-labour price growth to be zero. That is, we forecast non-labour price growth to match the growth of the CPI. We consider this represents a realistic expectation of the cost inputs required to achieve the opex objectives.

Powercor initially proposed a material price growth rate of zero. However, it stated that since it submitted its regulatory proposal the Australian dollar has fallen considerably against the United States dollar. It stated that, as a result, it now expected real price growth in materials over the 2016–20 regulatory control period. Accordingly it proposed real price growth for its 'non-labour' component that is a weighted average of the real price growth rate for materials forecast by Jacobs and a zero price growth rate for all other expenditure in its 'non-labour' component. This equates to a forecast annual non-labour price growth of 0.1 per cent.

By contrast, VECUA expressed concern that the prices of a number of the DNSPs' non-labour inputs were trending downwards and that the application of CPI is likely to over-estimate their costs. It stated that recent trends demonstrated that commodities prices (including copper, aluminium and steel) have fallen considerably. For example, the RBA commodities price index had dropped by around 20 per cent over the previous 12 months.<sup>204</sup>

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<sup>201</sup> DAE, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 41.

<sup>202</sup> See [www.employment.gov.au/trends-federal-enterprise-bargaining](http://www.employment.gov.au/trends-federal-enterprise-bargaining).

<sup>203</sup> DAE, *Forecast growth in labour costs in NEM regions of Australia*, 22 February 2016, p. 41.

<sup>204</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 66.



The real price growth rate for materials forecast by Jacobs that Powercor has used is Jacobs' forecast growth in the price of the 'overall material capital asset base'. Powercor did not provide any reasons why this forecast price change is appropriate for opex. We would expect different materials will be used by Powercor to operating and maintaining its network compared to those used when installing new assets. Regarding this, Powercor did not identify the materials it uses for the operation and maintenance of its network.

Importantly the CPI is made up of a basket of goods and services. The price of each of these goods and services will grow at different rates. Powercor have not provided any evidence that the price of non-labour inputs overall will grow at a different rate to the CPI. It did not demonstrate that the CPI growth will not compensate it for the price growth of materials it will purchase, which it did not identify. Similarly, VECUA did not provide any evidence that the CPI would overcompensate Powercor for the materials it purchases. For example, we would expect fuel costs to be a significant materials expense for Powercor. Automotive fuel accounts for 3.55 per cent of the CPI basket.<sup>205</sup> We note that materials accounts for 7.13 per cent of Powercor's proposal non-labour price growth.<sup>206</sup> We consider CPI growth will compensate Powercor for the growth in the price of fuel, even if fuel prices grow at a significantly different rate to the CPI.

Further, it is not reasonable to assume some non-labour prices will increase by more than CPI, while all other non-labour prices will increase by CPI. This is because while the real price of some items will increase, others will decrease. Adjusting only for real cost increases, and not decreases, produces upwardly biased price forecasts. In order to establish that compensation for non-labour real price escalation is necessary, there must be evidence the entire basket of non-labour prices will increase by more than CPI. Consequently, even if there is evidence the price of particular materials will increase more than CPI this does not necessitate that Powercor's non-labour prices will increase by more than CPI. Regarding VECUA's submission, the inverse equally applies. Even if there is evidence the price of particular materials will increase less than CPI this does not necessitate that Powercor's non-labour prices will increase by less than CPI.

We also have a number of concerns with Jacobs' approach to forecasting the price growth of materials:

- Jacobs' forecasting method does not account for the forecast price change in all factors of production, including the change in the price of capital, energy or services. Importantly, it does not include forecast productivity change in the manufacture of the materials Powercor purchases.
- Neither Powercor nor Jacobs provided evidence of how the prices of the materials Powercor purchases have changed over time.

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<sup>205</sup> ABS, catalogue 6470.0, *Information Paper: Introduction of the 16th Series Australian Consumer Price Index*, Appendix 2, 22 September 2011.

<sup>206</sup> Powercor, MOD 1.40 PAL Opex Non-Labour Escalation.

- Jacobs did not demonstrate how its forecasting model fits the historic price of materials. It provided no evidence that its forecasting method produces price forecasts more accurate than the no-change forecast.

We also note the most significant input price increase was for oil. Jacobs forecast that the price of oil in Australian dollars would increase by 20.9 per cent in real terms in 2016. The average price of oil in January and February of 2016 has been \$44 compared to an average of \$67 in 2015, a fall of 34 per cent. These results demonstrate the difficulty in forecasting the price of oil. Many oil experts consider forecasting oil prices extremely difficult, if not impossible, to forecast. For example, Peter Davies, chief economist of British Petroleum, has stated that 'we cannot forecast oil prices with any degree of accuracy over any period whether short or long'.<sup>207</sup> The US Federal Reserve has previously found that over horizons of several years the no change forecast adjusted for expected inflation was a better predictor of nominal oil prices than futures, expert economic forecasts, and the unadjusted current price of oil.<sup>208</sup> We note that while Jacobs tested the accuracy of three different oil price forecasts, it did not compare these to the no-change forecast.<sup>209</sup>

For these reasons we are not satisfied that Powercor's forecast materials price growth represents a realistic expectation of the cost inputs required to achieve the opex objectives.

### B.4.3 Price weights

We have weighted the forecast price growth to account for the proportion of opex that is labour and the proportion that is non-labour. We have adopted a 62 per cent weighting for labour and 38 per cent for non-labour. We have forecast the labour component based on the utilities WPI and we base the non-labour component on the CPI. These weights are consistent with those used in Economic Insights' benchmarking analysis. They are also consistent with the weights we used for our preliminary decision.

We consider that we should base the price weights we use to forecast price growth on a prudent and efficient benchmark network service provider. Using benchmark price weights provides service providers an incentive to make efficiency gains by adopting the most efficient input mix. Weights of 62 per cent for labour and 38 per cent for non-labour represent the best available estimate available for the benchmark efficient firm. We also note that once we adjusted Powercor's weights to reflect our definitions of labour, its revealed firm specific weight for labour is likely to be less than our benchmark weight.

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<sup>207</sup> Alquist, R., Kilian, L. And Vigfusson, J., Forecasting the Price of Oil, Board of Governors of the Federal Reserve System International Finance Discussion Papers, Number 1022, July 2011, p. 26.

<sup>208</sup> Alquist, R., Kilian, L. And Vigfusson, J., Forecasting the Price of Oil, Board of Governors of the Federal Reserve System International Finance Discussion Papers, Number 1022, July 2011, p. 2.

<sup>209</sup> Jacobs, *Escalation indices forecast 2016–2020*, 17 November 2015, p. 23.

Powercor did not use the same weights as us, although it did revise its price weights in its revised regulatory proposal. Like us, it divided opex price growth into 'labour' and 'non-labour' components. However, it included more expenses in its labour component, including:<sup>210</sup>

- its labour costs as reported in its category analysis RIN response, which includes its employees and labour hire contracts
- field services contracts for maintenance services (including line inspection).

Powercor's 'non-labour' component included all other opex.<sup>211</sup>

Powercor proposed input price weightings based on an average of its actual expenditure on labour and non-labour over the three year period 2012 to 2014. This resulted in weights of 72.1 per cent for labour and 27.9 per cent for non-labour.<sup>212</sup>

Consequently, there are two key differences between our input price weights and Powercor's:

1. we only included the labour component of field services contracts in our labour component whereas Powercor included all field services contracts costs
2. we used benchmark weights whereas Powercor proposed weights based on its firm specific expenses.

We discuss both of these differences below.

### ***Components of price growth***

In order to forecast the rate of change under the opex forecasting method set out in our *Expenditure forecast assessment guideline*, we need to define our inputs. This is required to forecast price change and productivity change. Opex inputs are generally classified as labour, services or materials.

In our preliminary decision we included both labour directly employed by a benchmark efficient service provider and labour employed by contractors to provide field services as labour. We stated that:<sup>213</sup>

We define labour 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 growth and the forecast productivity growth in our opex forecast. We do this because when we measure historic productivity growth we are interested in the productivity growth achieved by the service providers rather than the productivity growth achieved by contractors providing services that are not unique to electricity distribution.

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<sup>210</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 66.

<sup>211</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 66.

<sup>212</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 66.

<sup>213</sup> AER, *Preliminary decision*, Attachment 7, p. 61.

Powercor and Frontier Economics misinterpreted this statement. Frontier Economics interpreted our statement as meaning ‘that productivity improvements contributed by contract labour providing non–field services should be ignored’.<sup>214</sup> However, it is important to make the distinction between the efficiency with which the DNSP uses contracted services versus the efficiency improvements the contractor might achieve in supplying the specified services. Economic Insights provide an example that clarifies this distinction.<sup>215</sup>

Take the example where a DNSP purchases non–field services from a contractor and the quantity and price of the services it purchases does not change. If the DNSP’s outputs delivered and the other inputs used by the DNSP also remain constant then the DNSP’s productivity will not change. But if the contractor has been able to deliver those services to the DNSP with less labour (or any other input) then the contractor’s productivity will have grown. However, the contractor’s productivity growth is not reflected in the productivity change measured for the DNSP, at least not in the short run.

This is because what we are measuring for the DNSP is the quantity of services the DNSP uses—in this example this is the quantity of the output the contractor supplies which is in turn the input used by the DNSP. We attempt to measure this service quantity by deflating the cost of the service (or contract in this case) by the closest producer price index. If the contractor achieves productivity gains then his profits will increase in the short run. If the market for these services is reasonably competitive then we would expect the price of the service to subsequently fall (or increase less rapidly). We would expect that to subsequently be reflected in a lower cost of the contract for the DNSP which would in turn be deflated by a lower PPI, leaving the quantity of the service used by the DNSP unchanged, assuming the DNSP has not achieved productivity gains in the use of the service itself.

Economic Insights’ example equally applies to our opex forecasting approach. The forecast rate of change is a function of the forecast growth in price, output and productivity. By not including contract labour providing non–field services in our definition of labour we are not ignoring productivity improvements contributed by that labour. Rather productivity improvements contributed by that labour will be included in the price of non-field services, to the extent the contractor passes on those productivity improvements in the prices it charges Powercor.

Despite Powercor’s concerns with our definition of labour expenditure, its definition is broadly consistent with ours. The only difference is that it included all field services contracts expenditure in its labour weight. We only included the labour component of field services contracts in our labour weight. It considered defining labour in this way would yield opex forecasts that reasonably reflect the opex criteria because.<sup>216</sup>

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<sup>214</sup> Frontier Economics, *Review of AER’s Preliminary Decision on opex input weights*, December 2015, p. 12.

<sup>215</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, pp. 6–7.

<sup>216</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 62.

- it allows expenditure with the same cost drivers, or the same overall level of growth, to be grouped together
- the proportion of opex falling within each component can be robustly measured.

It considered that failure to meet either of these criteria may suggest it is necessary to reconsider redefining the components of real price growth.<sup>217</sup> We agree these are relevant considerations when defining the components of real price growth.

We stated in our preliminary decision that it had become increasingly difficult to determine the exact split between the labour component and the materials and services component of operating expenditure, as we had defined them.<sup>218</sup> Powercor stated that it had undertaken the exercise of allocating its actual expenditure between labour and non-labour components, thus demonstrating that the difficulties were surmountable. However, Powercor allocated expenditure to labour and non-labour according to its definition, which allocates all field services contracts expenditure to labour. The lack of evidence on the split of field services contract expenditure between labour and non-labour prices is one of the key reasons why we stated it had become increasingly difficult to determine the exact split between the labour and non-labour components.

So we agree that defining labour costs the way Powercor has makes it easier to measure the labour weight. But we do not agree that the price of internal labour and labour hire contracts is subject to the same cost drivers as contracted field services. This is because it is not appropriate to assume the price of field-services contracts will change at the same rate as labour prices. Field services contractors have inputs other than labour. These will include inputs such as the costs of:

- tools and other equipment used to provide the field services
- materials used to provide the field services
- vehicles including insurance, registration, fuel and servicing
- owning or leasing offices and other buildings and maintaining them.

Powercor's assumption ignores the price change of these other inputs. Consequently Powercor's definition of its opex inputs fails to meet its first criterion. It does not allow expenditure with the same cost drivers, or the same overall level of growth, to be grouped together.

Powercor effectively assumed that field services contractors have only one input, which is labour. This is not a reasonable assumption. A more reasonable assumption is to assume that the labour to non-labour input mix is the same regardless of whether Powercor provides field services in-house or outsources them. This is reasonable because the same tasks will be undertaken regardless of whether they are outsourced

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<sup>217</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 60.

<sup>218</sup> AER, *Preliminary decision*, Attachment 7, October 2015, pp. 62–63.

or not. This is equivalent to assuming that the input mix of the field services contractor is the same as Powercor. If we make this assumption Powercor's opex over the period 2012 to 2014 was 58.6 per cent labour and 41.4 per cent non-labour. Thus under this assumption the labour weighting based on Powercor's actual expenditure would be less than our benchmark weighting of 62 per cent. It is also worth noting that this assumption results in the same forecast price change regardless of the level of field services contracting.

### ***Benchmark versus firm specific weights***

We have used benchmark input price weights to derive our alternative estimate of opex. We consider the benchmark weights produce an opex forecast consistent with the opex criteria. We also consider that using a firm's revealed rate of change, for example by using its firm specific input weights, diminishes its incentive to reduce opex by reducing its rate of change. We discuss above the incentive impacts of using a firm's revealed rate of change.

Powercor stated that there was no sound basis to argue that its proposed opex input mix was inefficient if we found its base opex to be efficient.<sup>219</sup> Frontier Economics made this point in a report it prepared for Powercor.<sup>220</sup> Frontier Economics presented what it called a stylised representation of a production possibility frontier.<sup>221</sup>

It stated that:

- the line represented all combinations of the two inputs that maximise production outputs
- any combinations that lie above the line are infeasible
- any combination below the red line represents an inefficient combination of inputs.

It stated that a DNSP that lies on the line would be productively efficient as it would be maximising outputs with the inputs available.<sup>222</sup>

It stated that finding an NSP's base opex to be efficient, but its base year input mix to be inefficient was akin to saying a that an NSP was on the line and below it at the same time. It did not consider this feasible.<sup>223</sup>

We disagree with Frontier Economics' assessment. Firstly, and as pointed out by Economic Insights, Frontier Economics ignored the fact that the efficiency assessment used an opex price index that had a 62 per cent weight applied to the EGWWS WPI. It is technically possible that a DNSP could in fact have used a higher share of an opex

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<sup>219</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 65.

<sup>220</sup> Frontier Economics, *Review of AER's Preliminary Decision on opex input weights*, December 2015.

<sup>221</sup> Despite calling it a production possibility frontier the chart presented by Frontier Economics looks more like an isoquant. Firstly, the axes were the inputs, not the outputs. Secondly, the curve was convex not concave.

<sup>222</sup> Frontier Economics, *Review of AER's Preliminary Decision on opex input weights*, December 2015, p. 15.

<sup>223</sup> Frontier Economics, *Review of AER's Preliminary Decision on opex input weights*, December 2015, p. 16.



input whose price increased less rapidly than, say, the WPI. If Economic Insights had used these weights in its efficiency assessment then the DNSP's estimated opex quantity would increase relative to the current assessment and Economic Insights could have found the DNSP to be inefficient. Economic Insights admitted this scenario was unlikely to occur in practice but it was technically possible. What this highlights is the need to use a consistent price index in the efficiency assessment and the opex real price growth component of the rate of change when applying the base–step–trend method.<sup>224</sup>

Secondly, Frontier Economics' assessment only considered productive efficiency. It did not consider cost. Productive efficiency means that the firm is producing the most output it can produce with a given combination of inputs. It does not mean that the firm is producing a given level of output at the lowest cost.

Powercor's proposal that we should use its revealed input mix because we found it not to be materially inefficient ignores the input mixes of other DNSPs we also found to not be materially inefficient. The input mixes of the DNSPs we found not to be materially inefficient varied. Some used a lower proportion of labour than others. All else equal a lower labour proportion will result in a lower opex forecast because we forecast the labour price to increase more than the non-labour price.

In our preliminary decision we raised concerns that using a firm's revealed input mix to forecast opex would provide an incentive for that firm to adopt an inefficient input mix. Powercor did not share our concerns.<sup>225</sup> Powercor referred to Frontier Economic, who stated that:<sup>226</sup>

- our use of benchmarking encourages the pursuit of efficiency
- under the regulatory framework, distributors face incentive mechanisms that provide incentives to make savings whenever the opportunity arises, rather than deferring savings strategically
- we have overstated how easy it is in practice to change the input mix and assumed away the significant costs associated with doing so.

As also discussed by Economic Insights, Frontier Economics failed to recognise the distinction between the dollar value of opex and its composition.<sup>227</sup> The incentives to which Frontier Economics referred all operate at the total opex level. With all of these incentives in place, if a DNSP knows we will use its revealed input mix to forecast opex then it has an incentive to use more of the input in the base year that will increase in price more rapidly. As noted by Economic Insights, using the best estimate available of the appropriate weights of labour and non–labour components of opex and applying

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<sup>224</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, p. 8.

<sup>225</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 65.

<sup>226</sup> Frontier Economics, *Review of AER's preliminary decision on opex input weights*, December 2015, pp. vii, 14–17.

<sup>227</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, pp. 7–8.

these to all DNSPs, removes the incentive to skew either actual, or reported, opex composition towards components with faster growing prices.<sup>228</sup>

We note that Powercor has proposed determining the weightings by reference to an average of its input mix over a numbers of years. Powercor considered this would remove any incentive to adopt an inefficient input mix in the base year by ensuring there is no reason to distort the input mix in any given year.<sup>229</sup> However, we remain concerned that using an historic average of Powercor's input mix would diminish its incentive to reduce opex by adopting a more efficient input mix. Using an industry benchmark instead would provide an incentive to adopt the most efficient input mix.

As we have discussed above, analysis previously undertaken by Jeff Balchin, and submitted to the AER by ElectraNet, shows that:<sup>230</sup>

...it is inappropriate and inconsistent with the incentive framework for the assumed trend or trajectory after the base year to be based upon the observed performance in the preceding regulatory period.

Thus we can see that using a firm's revealed input mix would provide a disincentive to use less of an input that is increasing more rapidly in price because it would reduce the forecast rate of change. This would not be in the long term interest of consumers.

Powercor raised four concerns with our use of the input price weights derived by Pacific Economics Group (PEG).<sup>231</sup>

1. the data PEG based its analysis on is now over ten years old
2. PEG did not derive weightings for 'labour' and 'non-labour'
3. the mapping exercise conducted by PEG does not align with the components of opex defined by us
4. we did not review the veracity of the data underpinning PEG's weights.

As discussed by Economic Insights, there are a number of challenges in identifying the input mix of a prudent and efficient DNSP.<sup>232</sup> However, like Economic Insights, we are satisfied that the PEG input weights remain the best available estimate of the labour and non-labour component weights of opex. As noted by Economic Insights they are consistent with the widely varying reported information currently available from the Victorian and South Australian DNSPs.<sup>233</sup> We also note that Jemena and United Energy adopted these weights in their revised regulatory proposals.<sup>234</sup>

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<sup>228</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, p. 8.

<sup>229</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 65.

<sup>230</sup> PWC, *Operating expenditure efficiency assumption and the efficiency benefit sharing scheme*, 16 January 2013, p. 6.

<sup>231</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 62–63.

<sup>232</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, pp. 2–4.

<sup>233</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, pp. 4–5.

<sup>234</sup> Jemena, *Revised regulatory proposal*, 6 January 2016, p. 52.

United Energy, *Revised regulatory proposal*, 6 January 2016, p. 63.



We also note that Powercor's second and third concerns, which are closely related, have an immaterial impact. Powercor is correct that PEG did not disaggregate opex into labour and non-labour. As discussed by Economic Insights, PEG allocated what it considered to be the most appropriate available price index from the ABS to each opex cost category.<sup>235</sup> Regardless of the way opex was disaggregated, PEG considered the most appropriate available price index for 62 per cent of opex was a labour price index. Similarly it considered five producer price indexes were the most appropriate available price index for the remaining 38 per cent of opex. Economic Insights also showed that aggregating the five producer price indexes using the relative weights listed above and the Fisher index method produces a non-labour price index which closely tracks the CPI. This indicates the CPI is likely to be a good proxy for the non-labour price component for forecasting purposes.<sup>236</sup> Consequently there is no material inconsistency between PEG's approach to allocating price indexes to opex inputs and our own.

#### **B.4.4 Forecast output growth**

We have applied a forecast output growth rate of 1.7 per cent per annum in our estimate of the overall rate of change. We consider this reasonably reflects the increase in output a prudent and efficient service provider would require to achieve the opex objectives. There is a small difference between Powercor's forecast output growth rate, which averaged 1.6 per cent per annum, and our forecast because:

- we updated our output weights to match those in our latest benchmarking report
- Powercor did not ratchet its peak demand forecast.

##### ***Our approach to forecasting output growth***

We have maintained our preliminary decision method to forecast output growth.<sup>237</sup> We updated our output weights to match those in our latest benchmarking report. The output growth factors we used and their respective weights are:

- customer numbers (73.9 per cent)
- circuit line length (8.7 per cent)
- ratcheted maximum demand (17.4 per cent).

Powercor stated that it adopted our approach to forecasting output growth in its revised regulatory proposal. It also adopted the customer numbers and circuit line length growth forecasts in our preliminary decision, which were consistent with those in its initial proposal.

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<sup>235</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, pp. 2–3.

<sup>236</sup> Economic Insights, *Memorandum to AER, Opex input price index weights*, 19 February 2016, p. 4.

<sup>237</sup> AER, *Preliminary decision*, Attachment 7, October 2015, p. 66.

We used the forecast customer numbers and circuit length adopted by Powercor in its revised regulatory proposal opex model, which were consistent with our preliminary decision. This produces an average annual growth rate of 1.79 per cent for customer numbers and 0.45 per cent for circuit length.

### ***Forecast growth in peak demand***

For the reasons discussed in attachment 6, appendix C, we are satisfied that Powercor's forecasts of maximum demand reflect a realistic expectation of the demand forecast required to achieve the opex objectives. However, Powercor did not ratchet its maximum demand forecasts.

We ratcheted the maximum demand we use as an output measure in our output specification. Ratcheted maximum demand is the highest value of maximum demand observed up to the year in question. It recognises capacity Powercor used to satisfy demand and gives it credit for this capacity in subsequent years, even if annual maximum demand is lower in subsequent years.

Powercor's forecast peak weather corrected demand to be 2470.0 MW in 2015.<sup>238</sup> It forecast peak demand to be lower than this in 2016. Consequently we set ratcheted peak demand to this level for 2016.

### **B.4.5 Forecast productivity growth**

We have applied a zero per cent productivity growth forecast in our estimate of the overall rate of change. This reflects our expectations of the forecast productivity for an efficient service provider in the short to medium term. This is consistent with Economic Insights' recommendation to apply zero forecast productivity growth for other distribution network service providers such as Ergon Energy.<sup>239</sup> This is also consistent with our preliminary decision.

Powercor also included forecast productivity growth of zero in its rate of change.

The Guideline states that we will incorporate forecast productivity in the rate of change we apply to base opex when assessing opex. Forecast productivity growth will be the best estimate of frontier shift.<sup>240</sup>

We consider past performance to be a good indicator of future performance under a business as usual situation. We have applied forecast productivity based on historical

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<sup>238</sup> Consistent with our preliminary decision and Powercor's revised regulatory proposal we used non-coincident summated weather adjusted system annual maximum demand with a 50 per cent probability of exceedance measure at the transmission connection point in MW. We sourced the historic peak demand values from Powercor's annual benchmarking RINs.

<sup>239</sup> Economic Insights, *Response to Ergon Energy's Consultants' Reports on Economic Benchmarking*, 7 October 2015, p. 29.

<sup>240</sup> AER, *Better regulation explanatory statement expenditure forecast assessment guideline*, November 2013, p. 65.

data for the electricity transmission and gas distribution industries where we consider historical data to be representative of the forecast period.

To reach our best estimate of forecast productivity we considered Economic Insights' economic benchmarking, Powercor's proposal, our expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries. We discuss these further in our preliminary decision.<sup>241</sup>

VECUA, however, stated that our decision to apply zero productivity growth 'is illogical and is not supported by the evidence'. It stated that we need to forecast positive productivity growth for the Victorian distributors to bring their productivity back into line with their previous productivity levels and into line with the levels the electricity transmission, gas distribution and other asset intensive industry sectors achieve.<sup>242</sup>

VECUA claimed that a key reason for the distributors' productivity declines during the previous regulatory period was our provision of excessive opex allowances. It considered this was a strong driver of the networks' inefficient labour practices. It stated that such factors must not be used to justify poor productivity outcomes in future years.<sup>243</sup> VECUA, however, provided no evidence to support these claims. We note that productivity declines have not been unique to Australian electricity distribution networks. We have seen similar declines in productivity in Ontario and New Zealand,<sup>244</sup> which operate under different regulatory frameworks. Further, we are unaware of any incentive for the Victorian DNSPs to increase their actual opex when it is not efficient to do so. We consider the drivers of recent productivity declines in our assessment of Powercor's base opex in appendix A.

Although it stated that forecast productivity growth should be positive, VECUA did not suggest a basis on which to forecast positive productivity growth. VECUA did state that some of its participants operate in asset intensive industries that have delivered positive productivity growth during the 2006–13 period.<sup>245</sup> However it did not identify which industries it was referring to or why those industries would be an appropriate benchmark for electricity distribution. The CCP also considered forecast productivity should be positive. However, it did suggest we should consider the approach IPART uses to forecast productivity growth for the industries it regulates.<sup>246</sup> The approach the CCP referred to was the approach used by IPART to regulate rural and regional buses and local council rates. IPART forecast productivity based on the 15-year average of the ABS market sector value-added multifactor productivity (MFP) based on quality adjusted hours worked. It sets forecast productivity growth to zero when the 15 year

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<sup>241</sup> AER, *Preliminary decision*, Attachment 7, October 2015, pp. 69–73.

<sup>242</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 5.

<sup>243</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 67.

<sup>244</sup> Economic Insights, *Electricity distribution industry productivity analysis: 1996–2014*, 30 October 2014, p. iii.

<sup>245</sup> VECUA, *Submission to the AER*, 6 January 2016, p. 67.

<sup>246</sup> CCP, *Submission*, 25 February 2016, p. 30.

average is negative.<sup>247</sup> The 15 year average productivity growth for the utilities industry is –3.3 per cent. Consequently IPART’s approach to forecasting productivity also results in forecast productivity growth of zero.

Consistent with previous submissions, the Victorian Department of Economic Development, Jobs, Transport and Resources (DEDJTR) stated that:<sup>248</sup>

... with the rollout of smart meters in Victoria substantially complete, the AER should expect the Victorian DNSPs to realise efficiency gains from the rollout. These efficiency gains should be passed through to customers as the benefits are realised, as it is their customers, rather than the DNSPs, that have funded the investment in smart meters through a cost recovery regulatory regime.

We stated in our preliminary decision that DEDJTR had not identified or quantified the 'value added benefits' or the further benefits it expected to be realised over the 2016–20 regulatory control period. We stated that without this information we could not incorporate them into our opex forecast. We also note that DEDJTR had not provided us the independent assessment of the benefits of the AMI program that it had referred to.<sup>249</sup>

DEDJTR stated in its submission on our preliminary decisions that Deloitte forecast the benefits associated with the rollout of smart meters in a public report it prepared in 2011 for the Department of Treasury and Finance.<sup>250</sup> The most significant benefits identified in this report relate to capex and metering expenditure. Deloitte also identified some 'other smaller benefits' that may be relevant to standard control services opex. Of these smaller benefits, the most material reductions in standard control services opex are from:<sup>251</sup>

- the avoided cost of investigation of customer complaints about voltage and quality of supply
- the avoided cost of investigation of customer complaints about loss of supply which turn out to be not a loss of supply
- reduction in calls to faults and emergencies lines
- reduced cost of network loading studies for network planning.

DEDJTR stated that a recent review it undertook indicates that the DNSPs are in the early stages of realising these benefits and therefore their revealed 2014 operating expenditure would not reflect them.<sup>252</sup> DEDJTR did not provide this review. It also did not identify how the savings are allocated across the DNSPs and the extent to which these savings are reflected in base opex.

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<sup>247</sup> IPART, *IPART cost indices—productivity factor*, Fact sheet, October 2014, pp. 1–2.

<sup>248</sup> DEDJTR, *Submission*, 14 January 2016, p. 1.

<sup>249</sup> AER, *Preliminary decision*, Attachment 7, p. 72.

<sup>250</sup> Deloitte, *Advanced metering infrastructure cost benefit analysis*, 2 August 2011.

<sup>251</sup> DEDJTR, *Submission*, 14 January 2016, p. 3.

<sup>252</sup> DEDJTR, *Submission*, 14 January 2016, p. 3.

Powercor stated in its revised regulatory proposal that the benefits of the Advanced Metering Infrastructure (AMI) rollout that it has realised to date have largely been realised through savings in alternative control services opex and are already reflected in its base metering operating expenditure. It stated the same was true of standard control services opex and thus its standard control services opex forecast already reflected the productivity benefits of AMI.<sup>253</sup>

Powercor further stated that it expects the future benefits of the AMI rollout will relate to capex, rather than opex. It stated access to AMI data mostly provides future capital expenditure savings, for example by enabling improved network and community safety and improved network investment decisions, including the potential to defer network augmentation.<sup>254</sup>

In response to DEDJTR's submission, Powercor set out its progress to date on each of the categories of smart meter benefits identified and how it is sharing the benefits with its customers. It noted that it undertook its smart meter rollout within the timeframes set out by the Victorian Government. Further, the rollout was 96 per cent complete by 31 December 2013.<sup>255</sup>

Powercor stated that once it reached a critical mass of smart meter coverage it commenced implementation of business initiatives aimed at leveraging smart meter benefits.<sup>256</sup> These included business initiatives implemented to achieve the smaller benefits identified by Deloitte. Powercor described each of these initiatives and when it implemented the initiatives. In each case Powercor implemented the initiative prior to the commencement of the 2014 base year.<sup>257</sup>

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<sup>253</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 159.

<sup>254</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, p. 159.

<sup>255</sup> Powercor, *Submission*, 4 February 2016, p. 6.

<sup>256</sup> Powercor, *Submission*, 4 February 2016, p. 6.

<sup>257</sup> Powercor, *Submission*, 4 February 2016, pp. 9–12.

## **C Step changes**

In assessing a service provider's total opex 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 Powercor for the 2016–20 regulatory control period.

### **C.1 Final position**

In our final decision opex forecast we have included step changes for the following proposals:

- mobile devices
- customer information system and customer relationship management
- RIN compliance
- introduction of chapter 5A.

In total these step changes contribute \$10.2 million (\$2015) to our total opex forecast for Powercor for the 2016–20 regulatory control period.

**Table 7 Powercor step changes (\$ million, 2015)**

	Initial proposal	Preliminary decision	Revised proposal	Final decision
Customer charter	0.5	–	-	-
Superannuation - accumulation members	4.6	–	-	-
Monitoring IT security	2.0	–	2.0	-
Mobile devices	4.1	–	3.5	3.5
Customer Information System and Customer Relationship Management	5.2	3.1	3.1	3.1
Introduction of cost-reflective tariffs	-	-	5.5	-
RIN compliance	-	-	2.5	2.5
Introduction of chapter 5A	-	-	1.0	1.0
<b>Total</b>	<b>18.3</b>	<b>3.1</b>	<b>17.7</b>	<b>10.2</b>

Source: Powercor, *Regulatory proposal*, April 2015; AER preliminary decision opex model; Powercor, *Revised regulatory proposal*, January 2016; AER final decision opex model.

## C.2 Powercor's initial proposal and preliminary position

In its initial proposal, Powercor proposed five step changes to its base level of standard control services opex. Powercor stated the step changes reflect new or increased activities, or new or increased costs.

In addition, Powercor also forecast several categories of opex using a category specific forecasting approach (defined benefits superannuation, regulatory reset costs, GSL payments). The effect of this approach was a forecast incremental increase in opex in one category (defined benefits superannuation) and a decrease in two categories (reset costs/GSL payments).

In our preliminary decision, we included one step change in our opex forecast. We were satisfied that additional opex associated with Powercor's customer relationship management system arises due to new regulatory requirements, although we included a lower amount than Powercor had forecast.

## C.3 Powercor's revised proposal and submissions

In its revised proposal, Powercor accepted our revised forecast for the costs of its customer relationship management system. It did not re-propose step change for its

customer charter and superannuation (accumulation members) or category specific forecasts for defined benefits superannuation and regulatory reset costs.

Powercor re-proposed step changes for monitoring IT security and mobile devices. It revised its estimate for its mobile devices step change.

Powercor proposed new step changes for:

- the introduction of cost reflective tariffs
- RIN compliance
- introduction of chapter 5A.

We received general comments about our consideration of step changes from VECUA and the CCP. While VECUA has some residual concerns with the step changes we allowed in our preliminary decision, overall, it agreed with our assessments of the Victorian service providers' proposed step changes.<sup>258</sup> The CCP considered we were correct to reject most of the step changes in the Victorian service providers' proposals. It considered there is a tendency for the service providers to present a range of small cost increases without considering the overall ups and downs from year to year. It considered this results in a cumulative bias in the DNSPs' proposals.<sup>259</sup>

The Victorian Government submitted that in our preliminary decisions we did not accept step changes in operating expenditure that were not considered material. It stated it expects us to adopt the same approach in assessing the operating expenditure forecasts in the revised regulatory proposals.<sup>260</sup>

## C.4 Assessment approach

We have adopted the same assessment approach we used in our preliminary decision. This was set out in section C.3 of the preliminary decision.

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>261</sup> Our assessment approach specified in the Guideline<sup>262</sup> and is more fully described in section 7.3 of this attachment.

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<sup>258</sup> VECUA, *Submission to the AER Preliminary 2016–20 Revenue Determinations for the Victorian DNSPs*, 6 January 2016, p. 63.

<sup>259</sup> Consumer Challenge Panel Sub Panel 3, *Response to Preliminary Decisions made by the AER in response to proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016–20 regulatory period*, 10 February 2016, p. 17.

<sup>260</sup> Victorian Government, *Submission on the revised regulatory proposals, Victorian EDPR 2016–20*, 12 February 2016, p. 4.

<sup>261</sup> NER, cl. 6.5.6(c).

<sup>262</sup> AER, *Expenditure forecast assessment guideline*, November 2013, pp. 11, 24.



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 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 new office space required due to the service provider's expanding network. The opex forecast has already been increased (from the base year) to account for forecast network growth.<sup>263</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 opex items 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.

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<sup>263</sup> AER, *Explanatory statement: Expenditure forecast assessment 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. 164-165.

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>264</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
- 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>265</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>266</sup> For example, it may choose to lease vehicles when it previously purchased them. For these capex/opex

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<sup>264</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 11.

<sup>265</sup> AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

<sup>266</sup> AER, *Expenditure forecast assessment guideline*, November 2013, pp. 24 and 51–52.

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.

## C.5 Reasons for position

### C.5.1 Monitoring IT security

We have not included a step change for monitoring IT security in our opex forecast.

Powercor proposed a step change of \$2.0 million (\$2015) to monitor IT security. Powercor only undertakes active monitoring of security threats during business hours. It considers that as technology has matured, the risk and its exposure to this risk have increased. It proposed 24 hour active monitoring by an external service provider.<sup>267</sup> The forecast cost is shared equally between Powercor and CitiPower which has also proposed a step change of \$2.0 million (\$2015).<sup>268</sup>

In our preliminary decision we noted that IT security monitoring Powercor undertakes is a discretionary business decision. We would typically consider a service provider should be able to fund relatively small increases in discretionary opex without forecasting an increase in total opex. We did not see why this proposed expenditure should be treated differently.<sup>269</sup>

In response to our preliminary decision, Powercor repropoed the same amount for the step change. It referred to the reasons for the step change it outlined in its initial proposal. Powercor considered:

- The prevalence and risk of cyber attacks had increased along with Powercor's exposure to these attacks
- It is only recently that its incumbent IT providers have begun to propose 24 hour monitoring at competitive rates
- In late 2014, its security information and event management systems became operational. It considers this provides a framework that facilitates effective external monitoring, management and mitigation.
- The advance of technology means that what may have been prudent and efficient in 2014 is not sufficient to manage risk in 2016 and beyond.
- As its costs are already efficient, the disallowance of material prudent and efficient cost increases above its base year expenditure would result in an operating expenditure forecast that does not reflect efficient and prudent costs or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.

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<sup>267</sup> Powercor, *Regulatory proposal*, April 2015, pp. 188-189.

<sup>268</sup> CitiPower, *Regulatory proposal*, April 2015, p. 178.

<sup>269</sup> AER, *Preliminary decision, Attachment 7*, October 2015, p. 82.

- Opex is a more efficient solution than capex, and
- The AER's decision to reject this proposed step change is likely to result in higher prices for customers over the medium to long term. It considers if it is not allowed operating expenditure to monitor the security of its IT systems, it will have to inefficiently provide a capital expenditure solution to the issue which, due to the higher cost of such a solution, would result in higher prices for customers over the medium to long term;<sup>270</sup>

We have not changed our position on this step change.

As discussed above in section C.4 in most cases, we do not forecast step changes in opex for discretionary changes in inputs. By discretionary we mean a service provider has significant flexibility about what expenditure it carries out to address a particular issue. A service provider makes a wide range of discretionary decisions in carrying out its functions. We generally expect that discretionary opex should be funded by a service provider without increasing the revenue it recovers from consumers. In particular, where a change in discretionary expenditure is relatively small, we would expect a service provider would be able to make other small adjustments to other expenditure to accommodate these changes. Between Powercor and CitiPower, the forecast annual impact of this additional expenditure is 0.3 per cent of 2014 opex. While both service providers argue this is material<sup>271</sup> and cannot be funded without a step change, we disagree. We would expect that a discretionary expenditure increase of this magnitude can be accommodated by a service provider without forecasting increases in total opex.

Powercor also considers the prevalence and risk of cyber attacks have increased. It has referred to recent cyber security threats - for instance to Target, the Bureau of Meteorology and Sony Pictures.<sup>272</sup> It also provided information from the Australian Government Security Centre's Cyber Threat Report which reported that cyber security incidents have grown since 2011.<sup>273</sup>

While the Target, Bureau of Meteorology and Sony cyber attacks highlight some recent known cyber security breaches, information security threats to the utilities industry are not new. For instance in 2008, a CIA official reported that cyber attackers had hacked into the computer systems of utility companies outside the United States and made demands, in at least one case causing a power outage that affected multiple cities.<sup>274</sup> In 2003 a software flaw contributed to a widespread blackout across Northeastern USA and Canada.<sup>275</sup> The Australian Government recognised the threat of cyber security to

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<sup>270</sup> Powercor, *Regulatory proposal, Appendix G*, April 2015, pp. 10–12.

<sup>271</sup> Powercor, *Revised Regulatory Proposal*, January 2016, p. 164.

<sup>272</sup> Powercor, *Revised Regulatory Proposal*, January 2016, p. 165.

<sup>273</sup> Powercor, *Revised Regulatory Proposal*, January 2016, pp. 166–168.

<sup>274</sup> Washington Post, *Hackers Have Attacked Foreign Utilities*, CIA Analyst Says, January 19 2008.

<sup>275</sup> US-Canada Power System Outage Task Force, *Final Report on the August 14 2003 Blackout in the United States and Canada: Causes and Recommendation*, April 2004, pp. 51–57; Associated Press, *GE Acknowledges Blackout Bug*, 24 February 2004.

national information infrastructure as early as 1999.<sup>276</sup> This suggests that information security risks have presented a risk to utility providers for some time. The recent attacks Powercor highlighted in its proposal do not provide insight as to why it has become prudent and efficient for Powercor to only begin IT security monitoring 24 hours 7 days a week in the forthcoming regulatory control period.

We have also not put much weight on the Australian Government Security Cyber Security Threat report. This report does not identify the cyber security risks facing electricity distributors or identify the specific measures an electricity distributor should take to address these risks.

Powercor also considers its exposure to IT risks have increased with the growing convergence of its IT and operating systems. This, in our view, is also not a reason to increase the revenue it can recover from consumers. Powercor has made a discretionary business decision to converge its IT and operating systems. Consistent with all discretionary business decisions that Powercor makes, if this has been an efficient decision, it will receive commensurate financial benefits of this decision through the incentive framework. It would be inconsistent with the overall incentive framework if Powercor received some benefits of its technological convergence but did not bear the costs of such a decision.

We also do not consider it is relevant that Powercor's incumbent IT provider has only reportedly began offering 24 hour monitoring services. Powercor could have potentially engaged other external service providers or employed internal resources in or prior to the base year to monitor IT risks outside of business hours. If the risks of cyber attack are as extreme<sup>277</sup> as Powercor claims, then we would expect that some resources would have already been devoted to monitoring IT security outside of business hours.

Finally do we also do not see why in the absence of specific funding for this step change, Powercor would invest in a higher cost capex solution. Consistent with the incentive framework, Powercor is incentivised to seek the most efficient solution regardless of whether it is opex or capex and regardless of what funding it is provided with. If Powercor's opex is not adjusted for this program of expenditure, then as a profit maximising business, it is unclear why it would then go and invest in a higher cost capex solution.

## **C.5.2 Mobile devices**

We have included a step change for mobile devices in our final decision.

Powercor's existing approach for accounting for these devices is a mixture of capital and operating expenditure. It states that it capitalises costs of mobile devices (phones and tablets) and protective accessories, as well as the labour component associated

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<sup>276</sup> Australian Government, *Defence 2000 - Our Future Defence Force*, December 2000, p. 13; Australian Federal Police, *Protecting the national information infrastructure*, November 2000.

<sup>277</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 165.

with formatting and setting up these devices. The corresponding data and repair requirements are expensed. It considers that moving to an operating expenditure only model is a more efficient alternative.<sup>278</sup> In its initial proposal it estimated this will cost an additional \$4.1 million in opex.

We did not include this step change in our preliminary decision opex forecast. Powercor provided a benefit cost analysis to support its business approach with respect to mobile devices. However, in estimating the cost of this option, Powercor assumed that it would incur the capex associated with replacing all of its phones and tablets every two years. Powercor stated that the two year asset replacement cycle reflects the length of the maximum available warranty period from the manufacturer.<sup>279</sup>

On the basis of the evidence presented by Powercor, we did not consider it would be prudent to replace all smart devices every two years. The end of a warranty on a mobile device does not mean it would be efficient to replace that device. If a business owns its own phones and tablets, it can replace them when the devices fail. The useful life of many phones and tablets will extend beyond the warranty. We considered this assumption overstates the NPV of the capex that would likely to be required in the next regulatory control period if Powercor maintained its current approach to purchasing and leasing mobile devices. As we did not have confidence in the counterfactual estimate, we were not convinced its proposed change in approach would be efficient.<sup>280</sup>

We also noted that there were interactions between this proposed step change and Powercor's proposed capitalisation of corporate overheads. Powercor proposed to expense all of its corporate overheads in the next regulatory control period. Its methodology is to roll all the capitalised corporate overheads it incurred in 2014 into its base opex. We understood that its capitalised corporate overheads included the cost of purchasing new mobile devices. As Powercor also proposed a step change in opex for the cost of leasing mobile devices, we considered its forecast opex effectively included the cost associated with purchasing new mobile devices in 2014 (as a base year adjustment) plus the forecast cost of leasing new mobile devices (as a step change). We did not consider this approach was consistent with the opex criteria.<sup>281</sup>

In response to our preliminary decision, Powercor reconsidered the assumptions it had used for the life of its phones and tablets, based on a report by Gartner, an IT research and advisory company. It used a two year replacement cycle for field mobile phones and three years for office mobile phones and tablets.<sup>282</sup> The split of its field and office tablets is approximately 85 per cent field and 15 per cent office and the split of field and office mobile phones is approximately 55 per cent field and 45 per cent office.

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<sup>278</sup> Powercor, *Revised regulatory proposal, Appendix G step changes*, January 2016, p. 14.

<sup>279</sup> Powercor, *Response to information request: Vic EDPR – PC - #IR011 – 8 July 2015* [email to AER], 22 July 2015, p. 2.

<sup>280</sup> AER, *Preliminary decision, Attachment 7*, October 2015, p. 83.

<sup>281</sup> AER, *Preliminary decision, Attachment 7*, October 2015, p. 83.

<sup>282</sup> Gartner, *Recommended life spans for mobile, PC and other endpoint-computing devices*, 11 September 2015.



After its revised assumptions, its benefit cost analysis still shows it would be more efficient to move to an opex only mobile device strategy.<sup>283</sup> The changes in assumptions reduced the step change to \$3.5 million (\$2015).

Powercor also clarified how it had accounted for the cost of mobile devices purchased in the base year. The mobile costs included in 2014 capitalised corporate overheads were not the actual devices but data and telecommunications costs associated with increases in mobile devices.<sup>284</sup>

Based on the further information Powercor has provided in its revised proposal we are now satisfied that the proposed increase in opex for mobile devices does reflect an efficient capex/opex trade-off and there is no double counting of costs.

We are also satisfied with the assumptions underlying the forecast. These are based on the actual unit costs of replacing mobile devices in 2014 and the actual volumes replaced. We consider that basing the forecast step change on historical unit costs and volumes is a reasonable forecasting approach.

### **C.5.3 RIN compliance**

We have included a step change of \$2.5 million (\$2015) in our final decision opex forecast for RIN compliance. We are satisfied this step change is driven by a regulatory change.

As of 2015, we require economic benchmarking (EB) and category analysis (CA) regulatory information notice (RIN) reporting to be based on actual rather than estimated data. All the Victorian network service providers, except AusNet Services, proposed increases in opex and capex to make changes to their IT systems and business processes to meet our requirements for actual data.

Powercor's forecast RIN compliance costs represented 50 per cent of total RIN compliance costs for the combined CitiPower/Powercor project, allocated equally across both businesses.

In its initial proposals, CitiPower/Powercor proposed a capex only solution of \$28.8 million (\$2015) for both businesses to comply with the requirement to provide actual RIN data.<sup>285</sup> This option proposed meeting the RIN reporting requirement via automated reporting with the ability to adapt to changing RIN reporting requirements over time.

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<sup>283</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 171.

<sup>284</sup> CitiPower, *Revised regulatory proposal*, January 2016, p. 171.

<sup>285</sup> Powercor, *Regulatory proposal, KPMG on behalf of CitiPower and Powercor, Business Case for expenditure to meet RIN requirements*, April 2015, p. 7.

In our preliminary decision, we were not satisfied the magnitude of Powercor's proposed capex for RIN compliance costs was prudent and efficient.<sup>286</sup>

In its revised proposals, CitiPower/Powercor proposed an alternative RIN compliance solution for both businesses involving a mix of both capex and opex. The revised project relies less heavily on automated reporting and more on manual processes. It also no longer includes the capacity to adapt to changing RIN requirements in the future.

CitiPower/Powercor proposed a total project capex forecast of \$10.6 million together with an opex step change of \$5.0 million (or \$2.5 million per business).<sup>287</sup> On a total project basis, the revised RIN compliance cost of \$15.6 million (\$2015) reflects a reduction of \$12.3 million or 44 per cent from the initial proposal.

In assessing the need for any RIN compliance costs, we must be satisfied that they reflect the efficient costs that a prudent operator would require to comply with its regulatory obligations.<sup>288</sup> This will maximise the net benefits of RIN reporting to consumers in terms of enhanced industry efficiency, transparency, governance and data availability. We have assessed the proposed opex and capex together as a total project. We discuss Powercor's forecast RIN compliance capex in more detail in attachment 6 of this final decision.

CitiPower/Powercor submitted a business case and detailed costing model in support of its revised forecast RIN compliance costs.<sup>289</sup> This business case addressed a number of factors relevant to assessing the prudence and efficiency of this project:

- a description of the need for investment, with supporting evidence setting out the current capabilities of CitiPower/Powercor's systems to report actual data<sup>290</sup>
- evidence that CitiPower/Powercor considered a suitable range of options<sup>291</sup>
- an analysis of costs and benefits of the proposed options<sup>292</sup>
- evidence that CitiPower/Powercor selected the lowest cost option which meets regulatory requirements.<sup>293</sup>

The business case CitiPower/Powercor submitted supports the proposed option for achieving RIN compliance at a lower cost than its initial proposal through a more

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<sup>286</sup> AER, *Preliminary decision, Powercor distribution determination 2016–20 Attachment 6 - Capital expenditure*, October 2015, pp. 6-102 to 6-135.

<sup>287</sup> Powercor, *Attachment 1.56 - PAL RIN Compliance Expenditure*, 'Summary of Costs' tab, January 2016. Excludes escalation.

<sup>288</sup> NER, cl. 6.5.7(c).

<sup>289</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015; and Powercor, *Attachment 1.56 - CP RIN compliance expenditure*, January 2016.

<sup>290</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 6–14.

<sup>291</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 15–16.

<sup>292</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, pp. 17–18.

<sup>293</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.



efficient mix of both capex and opex.<sup>294</sup> This is evident in the 44 per cent reduction in total costs compared with the initial capex only option.<sup>295</sup> It delivers the overall least cost solution to comply with the new RIN reporting requirements.

CitiPower/Powercor stated during the 2016–20 regulatory control period it will incur additional opex above its base year operating expenditure on:

- RIN governance
- data element maturity
- increased auditing.

We are satisfied these increased costs reflect the efficient costs to comply with the new requirement to report actual data and are not already accounted for in the base opex forecast.

CitiPower/Powercor sought advice from its RIN auditors who advised that the increase in data classified as actual data will result in an increase in audit effort. This is because a higher level of assurance is required under the prescribed auditing standards. Actual data is required to be subject to an 'audit' which is a higher level of assurance than the 'review' required for estimated data. We accept the auditor's advice on this matter.

In part, the reduction in CitiPower/Powercor's forecast RIN compliance costs arises from focussing on delivering existing RIN reporting obligations rather than the capacity to adapt to future RIN requirement changes.<sup>296</sup> We agree that it is prudent for Powercor to seek to comply with applicable regulatory obligations, rather than unspecified possible future obligations which may or may not arise.<sup>297</sup>

In our assessment of the capex component of this step change we assess CitiPower/Powercor's revised proposal in the context of similar costs proposed by other network service providers. In that assessment we consider the combined total capex and opex costs for CitiPower/Powercor are approximately equivalent to the prudent and efficient level of costs for RIN compliance included in our final regulatory determination for SA Power Networks.<sup>298</sup>

Having reviewed the information submitted by Powercor in support of a step change of \$2.5 million (\$2015) for new RIN reporting requirements, we are satisfied it reflects the efficient costs of a prudent operator.<sup>299</sup>

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<sup>294</sup> NER, cl. 6.5.7(e)(7).

<sup>295</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 18.

<sup>296</sup> Powercor, *Attachment 6.20 - CitiPower and Powercor RIN reporting compliance*, December 2015, p. 16.

<sup>297</sup> NER, cl. 6.5.7(a)(2).

<sup>298</sup> AER, *Final decision, SA Power Networks distribution determination 2015-20*, October 2015, p. 7-75.

<sup>299</sup> NER, cl. 6.5.7(c).

## C.5.4 Vegetation management

We have not included a step change for Powercor's vegetation management costs in our opex forecast.

Powercor did not propose a step change related to vegetation management.

In our preliminary decision, we identified the potential for a negative step change for Powercor's vegetation management. We noted that Energy Safe Victoria (ESV) reintroduced exceptions in the *Electricity Safety (Electric Line Clearance) Regulations 2015* (ELC 2015) for reduced clearance distances for structural branches. ESV noted that the removal of these exceptions in the 2010 version of the ELC increased costs over time and expects that the reintroduction of these exceptions in ELC 2015 should decrease pruning costs over time.<sup>300</sup>

Based on this we considered there was scope for Powercor to reduce its costs to comply with its vegetation management obligations in the 2016–20 regulatory control period. However, we noted that the net impact of changes to ELC 2015 on Powercor's vegetation management costs was unclear and expected Powercor to address this after receiving guidance from ESV.<sup>301</sup>

In its submission to our preliminary decision, the Victorian Government identified increases in vegetation management expenditure under ELC 2010 compared to ELC 2005 for AusNet, Powercor and United Energy. It considered that the AER should assess both negative and positive step changes associated with the introduction of ELC 2015.<sup>302</sup>

In its revised proposal and response to submissions, Powercor considered its vegetation management costs for the 2016–20 regulatory control period would not decrease relative to base year vegetation management expenditure. To support this, Powercor noted:

- It received exemptions from ESV to comply with tree pruning requirements.
- As a result of these exemptions, Powercor did not undertake extra vegetation management to be compliant with structural tree branches pruning requirements in ELC 2010.
- It considers its existing practices and 2014 base year operating expenditure for vegetation management are consistent with ELC 2015.<sup>303</sup>

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<sup>300</sup> Energy Safe Victoria, *Response to AER email on electricity distribution proposals – ESV audit intent*, 28 July 2015, p. 4.

<sup>301</sup> AER, *Preliminary decision*, October 2016, p. 86.

<sup>302</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016–20*, 14 January 2016, p. 7.

<sup>303</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 178. Powercor, *Further submission to the AER regarding preliminary determination*, 4 February 2016, p. 22.

The CCP also asked us to assess the impact of changes to ELC 2010 and ELC 2015 on the 2014 base year.<sup>304</sup>

Based on the information provided by Powercor, we are satisfied that changes to ELC regulations to apply in the forecast period would not have a material impact on Powercor's vegetation management costs in the base year and the forecast period. Due to the exemptions granted to Powercor by ESV, Powercor's obligations for ELC 2015 are largely the same for Powercor as its current vegetation management practices reflected in the base year. Therefore, we do not consider the removal of the structural branches exceptions in ELC 2015 would have an impact on Powercor's forecast vegetation management costs relative to its 2014 base year.

The CCP also queried whether, if ESV did not enforce its ELC requirements as a result of providing exemptions to the DNSPs, the DNSPs would receive EBSS payments.<sup>305</sup>

The EBSS applies to total opex rather than the opex for individual regulatory obligations. Although in this circumstance the CCP have identified the costs to comply with an obligation has decreased, the costs of complying with other obligations may have increased. Under an incentive based regulatory regime, therefore, it would generally not be reasonable to make an ex-ante adjustment for the actual costs of complying with each individual regulatory obligation.

### **C.5.5 Introduction of cost-reflective tariffs**

We have not included a step change in our opex forecast for Powercor's cost-reflective tariffs step change.

In its revised proposal, Powercor proposed a new \$5.5 million (\$2015) step change for operating expenditure related to the introduction of cost-reflective tariffs in Victoria.<sup>306</sup>

In November 2014, the Australian Energy Market Commission (AEMC) made a new rule to require network businesses to set prices that reflect the efficient cost of providing network services to individual consumers.<sup>307</sup> Prices based on these new rules were to apply in Victoria from 1 January 2017.

Powercor forecast the following cost drivers to comply with its cost-reflective tariff obligations:

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<sup>304</sup> Consumer Challenge Panel sub-panel 3, *Response to the AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 32.

<sup>305</sup> Consumer Challenge Panel sub-panel 3, *Response to the AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 32.

<sup>306</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 174.

<sup>307</sup> AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

- It was required to undertake mass market mail-outs to help ensure its customers are aware of the introduction of the network tariff structure change and further mass mail-outs to further engage with its customers after the proposed tariffs have come into effect.
- Respond to customer enquiries regarding the new tariffs.<sup>308</sup>

### **Jemena's preliminary decision**

Powercor noted that its proposed step change was consistent with our preliminary decision for Jemena where we approved a similar cost-reflective tariff step change.<sup>309</sup>

As a part of final decision assessment, we have reassessed our position for Jemena's step change and we have not included Jemena's proposed costs related to mail outs and customer enquiries.

The new rule requires distribution businesses to consult with consumers and retailers to develop a tariff structure statement that outlines the price structures that they will apply for the regulatory period. The businesses will also publish an indicative pricing schedule each year to provide consumers and retailers with up to date information on likely price levels throughout the regulatory control period.

However, the AEMC rule change does not oblige Powercor to conduct mail-outs to notify customers of the new tariffs. Rather, the onus will be on the retailers to offer the new tariff structures as part of their product offerings. Similarly customers will direct most of their inquiries to retailers. Nor does the rule change require Powercor to promote the new tariffs to its customers.

For the reasons outlined above, we have reassessed our position for Jemena's step change and we have not included costs related to mail outs and customer enquiries.

### **Information request response**

In response to our information request notifying Powercor of our change in position for Jemena, Powercor maintained its forecasting approach for the following reasons:

- Although the AEMC rule change does not explicitly state that distributors must undertake mass mail-outs to all customers, this does not imply that mail-outs and ongoing customer engagement are not required.
- Its customers support the introduction of cost-reflective tariffs and the opex criteria includes expenditure to address the concern of electricity consumers.
- Cost reflective tariffs will benefit a material percentage of its consumers and high levels of customer enquiries are expected following the introduction of the tariffs.

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<sup>308</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 181.

<sup>309</sup> Powercor, *Revised regulatory proposal*, January 2016, p. 181.

- Without actively promoting its new tariffs, the benefits to Powercor's customers of cost reflective tariffs will not be realised.
- The AER has previously accepted step changes for Envestra's Victorian Network where the benefits of a discretionary project do not accrue to the distributor but may result in lower prices to consumers.<sup>310</sup>

We agree with Powercor on the importance of consumer awareness regarding cost-reflective tariffs. However, Powercor did not explain why it had to undertake these activities when it is the responsibility of retailers to pass on these tariffs to their customers. We consider distributors are not best placed to promote the take-up of cost reflective tariffs for the following reasons:

- The cost reflective tariff will not necessarily be reflected in retail electricity offers. Consequently, it is uncertain whether or not the distributor's cost reflective tariffs will have the impact on the retail offers that the distributor claims.
- The way in which consumers will see the networks tariffs will depend on how energy retailers choose to represent the new tariffs in their bills.

We note that Powercor conducted extensive stakeholder consultation with customers in developing its Tariff Structure Statement (TSS).<sup>311</sup> This process would ensure that retailers and customers would be able to understand Powercor's new tariffs.

However, the AEMC in its final determination noted retailers rather than distributors are the key stakeholder in consumer awareness. It stated:

Most consumers will gain an understanding of pricing signals through the retail tariffs they are charged. This is because for most consumers, their primary relationship will be with the retailer. As such, the role of retailers in providing information to facilitate understanding of pricing signals is critical.<sup>312</sup>

The AEMC also noted that retailers have a significant incentive to pass on network price signals in some form when deciding how to structure their retail prices.<sup>313</sup>

As noted above, Powercor identified a step change we approved for Envestra Victoria which included discretionary expenditure. We made this decision in the context of the gas market and increased consumer take up of gas products. This is a different circumstance to Powercor's proposed cost-reflective tariff expenditure. In the case of electricity, the AEMC has identified that it expects retailers to provide the relevant cost reflective tariff information. In this context, Powercor has not provided any substantive

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<sup>310</sup> Powercor, *Response to information request 42* [email to AER], 8 March 2016, pp. 1–2.

<sup>311</sup> Powercor, *Tariff structure statement 2017–2020: Overview paper*, 25 September 2015, p. 6.

<sup>312</sup> AEMC, *Rule determination National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. 67.

<sup>313</sup> AEMC, *Rule determination National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. viii.

analysis or evidence to suggest that its proposed step change in opex would provide broader market benefits that would advance the NEO.

As noted above Powercor is not obligated to notify its customers and we consider the retailer has primary responsibility to pass on changes in tariffs through their own retail tariffs.

### **Other submissions**

The Victorian Government submitted that customers must opt in to, rather than opt out from, cost reflective network tariffs and that the AER must assess whether the DNSPs' proposals are consistent with an opt-in approach.<sup>314</sup>

In response to the Victorian Government's submission, Powercor noted that its proposal did not explicitly consider the impact of an opt-in approach.<sup>315</sup>

The impact of an opt-in approach on Powercor's cost reflective tariff step change is not a relevant consideration in our assessment of this step change. This is because we have not included any of Powercor's proposed costs for this step change in our opex forecast.

## **C.6 Other costs not included in the base year**

### ***Guaranteed Service Levels***

We have forecast guaranteed service level (GSL) payments for the 2016–20 regulatory control period using an average of GSL payments made by Powercor between 2010 and 2014. Our forecast also reflects changes in the Electricity Distribution Code (EDC).<sup>316</sup>

We have included \$15.6 million (\$2015) for GSL payments in our opex forecast.

In its initial proposal, Powercor forecast GSL payments of \$ 11.6 million (\$2015). Powercor used a single base year to forecast GSL costs over the forthcoming regulatory control period.<sup>317</sup> Powercor did not account for regulatory changes to GSL obligations because the new EDC rules were not finalised at the time.

In our preliminary decision, we included in total forecast opex \$ 11.0 million (\$2015) for GSL payments over the 2016–20 regulatory control period. We forecast GSL payments as the average of GSL payments made by Powercor between 2010 and 2014. We adopted the historical averaging approach to maintain consistency with our GSL payment forecasting methodology for previous regulatory control periods. Further, the

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<sup>314</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016–20*, p. 6.

<sup>315</sup> Powercor, *Further submission to the AER regarding preliminary determination*, 4 February 2016, p. 17.

<sup>316</sup> Essential Services Commission, *Electricity Distribution Code Version 9*, December 2015, pp. 19–20.

<sup>317</sup> Powercor, *PAL - opex - mod 1.34 PAL GSL step change*, April 2015.

incentives provided by this forecasting approach are consistent with adopting a single year revealed cost approach and applying the EBSS.<sup>318</sup>

In its revised proposal, Powercor forecast GSL payments of \$ 17.1 million (\$2015). Consistent with our preliminary decision Powercor adopted our 2010 to 2014 averaging approach rather than a single base year to forecast GSL payments. However, Powercor:

- Increased its forecast to reflect anticipated increases in the size and the frequency of GSL payments under the new EDC.
- Included spending for Quality of Supply Monitoring and Recording.
- Adjusted GSL payments for forecast output growth.<sup>319</sup>

We discuss each component of Powercor's forecast in the sections below.

### **Electricity Distribution Code**

The Victorian Government submitted that the basis for Powercor's revised proposal was the draft EDC rules rather than the final EDC rules.<sup>320</sup> Powercor responded to our information request stating that it had forecast based on the final EDC rules.<sup>321</sup> We have assessed the likely increase in the size and frequency of GSL payments, due to the changes to the EDC and we consider Powercor's incorporation of these changes into its forecast is reasonable.

### **Quality of supply monitoring and output growth**

However, we do not consider Powercor's proposed costs for Quality of Supply Monitoring and output growth is prudent and efficient.

Powercor included, as new GSL costs, \$ 0.83 million (\$2015) to establish better quality monitoring. However, at present Powercor is under no obligation to perform monitoring as part of the GSL framework. We do not consider Powercor is required to incur such costs under the EDC, and have therefore removed this increment from allowed GSL costs.

Powercor adjusted GSL payments for forecast output growth. We do not consider that output growth can, in isolation, be shown to drive GSL costs which are volatile year to year. GSL payments apply to a small and distinctive subset of poorly served customers. Meanwhile, output growth reflects the changes in ratcheted maximum demand, circuit length and customer numbers. We do not consider output growth is a reasonable measure of growth in Powercor's GSL payments.

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<sup>318</sup> AER, *Preliminary decision Powercor – Opex model*, October 2015.

<sup>319</sup> Powercor, *Revised regulatory proposal*, 6 January 2016, pp. 144–147.

<sup>320</sup> Victorian Government, *Submission on the Victorian electricity distribution network service providers' revised regulatory proposals for 2016–20*, 12 February 2016, p. 4.

<sup>321</sup> Powercor, *Response to AER information request – Powercor - #043 [email to AER]*, 25 February 2016 : Powercor stated that they used the final EDC rules.



We also note that adjusting for output growth without also adjusting for other offsetting factors may distort the forecast. For example, Powercor forecast the size of its GSL payments to individual customers in real terms, even though GSL payments are fixed in nominal terms. This means that Powercor receives the benefit of forecast inflation even though its payments remain constant in nominal dollars for the 2016–20 regulatory control period since we have not adjusted for this in our forecast.

### **Other submissions**

The CCP noted the increased GSL payment forecast and suggested that the AER examine the forecast.<sup>322</sup> The CCP also suggested that GSL costs "could be recovered during the course of the regulatory period".<sup>323</sup> Realised GSL costs may be either higher or lower than forecast as they depend on the frequency of unplanned outages. Recovering GSL costs as the CCP suggests may also remove the incentive for the distributor to maintain service levels.

### ***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.

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<sup>322</sup> Consumer Challenge Panel sub-panel 3, *Response to the AER Preliminary Decisions and revised proposals from Victorian electricity distribution network service providers for a revenue reset for the 2016-2020 regulatory period*, 25 February 2016, p. 33.

<sup>323</sup> Consumer Challenge Panel Sub Panel 3, *Submission to the Australian Energy Regulator (AER) an overview*, 22 February 2016, p. 16.