



Oakley Greenwood

# Review of NSW DBs Regulatory Submission

prepared for:  
Energy Australia, Origin and AGL



## DISCLAIMER

This Report has been prepared for EnergyAustralia, Origin Energy and AGL (the Retailers) in accordance with the scope of work outlined by the Retailers. We note, for completeness, that this scope only sought our advice on:

- Unbundled metering charges, including exit fees, and
- Operating expenditure forecasts.

Further to the above, it should be noted that due to time constraints, in preparing this report, we have not reviewed every available Attachment and model provided by the businesses to the AER as part of their, or in support of their, Regulatory Proposals. Rather, our approach has been to place primary reliance on the businesses Regulatory Proposals, and the descriptions, assumptions and forecasts contained in those Regulatory Proposals. Where time has permitted, and where the issue was of a material nature, we reviewed a selection of relevant detailed Attachments/models, however this review by necessity was not all-encompassing. OGW would also note that this work has been undertaken independently and that no confidential or commercially sensitive information has been source from any of the Retailers for use in this report.

Therefore, this report should be read in this context and OGW disclaim liability for the use of any information in this report by any party for any purpose other than the intended purpose.

## DOCUMENT INFORMATION

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## 1. Objectives of this report

Oakley Greenwood were engaged by a consortium of Retailers - EnergyAustralia, Origin Energy and AGL to undertake analysis of specific aspects of the distribution businesses' initial revenue proposals for the period 1 July 2015 to 30 June 2019 - namely:

- Unbundled metering charges, including exit fees, and
- Operating expenditure.

Oakley Greenwood was asked generally to:

- Analyse and comment on the level of and assumptions underpinning Networks NSW's proposed unbundled meter charges and exit fees for each of the three NSW distribution networks, as specified in their initial regulatory proposals (submitted to the Australian Energy Regulator (AER) on 31 May 2014), and
- Critically assess the proposed operating expenditure for each of the three distribution networks, including its composition and underlying assumptions, and
- Identify those aspects of the proposed expenditure that appear inefficient, drawing on our economic and financial expertise and with reference to appropriate benchmarks, such as expenditure proposals by similar businesses, and
- Also have regard to the expected benefits of the merger of the three network businesses, in terms of operational efficiencies for example, and comment on whether any such benefits are apparent in the expenditure proposals.

A more detailed scope was provided directing OGW's investigations so they were more focused within the time frame allowed for submissions to be received by the AER, and this report responds to that focused scope. Our analysis has been undertaken specifically based on the material supplied publicly by the businesses and with reference to the NEO, NER and NEL, to economic efficiency principles, and has regard to previous determinations and relevant guidance from the AER.

It is clear from our review and this associated report that there are significant issues for the AER to consider related to both the metering fees approach and the operating cost forecasts in the submissions, and various inconsistencies across the three businesses as well in their proposals.

This reports attempts to outline these and where appropriate suggest alternative approaches or resolutions, or identify where the AER needs to focus their attention for consistency and efficiency gains for customers.

OGW would also note that this work has been undertaken independently and that no confidential or commercially sensitive information has been source from any of the Retailers for use in this report.

## 2. Approach to and calculation of Exit Fees

### 2.1. Introduction

This section of the report provides commentary and observations on:

- The approach used by the businesses in setting the Exit Fees proposed in their Regulatory Proposals;
- The specific calculations undertaken in doing so, and
- An alternative approach that is more consistent with economic theory and the NEO.

### 2.2. Overview of the approach used by the NSW distribution businesses

#### 2.2.1. Approach used

The approach the distribution businesses have taken in developing Exit Fees is based on a Depreciated Replacement Cost. It is consistent with - and in the case of Ausgrid they have quoted - the draft criteria for calculating Exit Fees that were included in the AEMC's *Power of Choice Final Report*<sup>1</sup>.

The use of the AEMC criteria is logical, but it should be noted that those criteria (a) are not specified in the NER or any regulation, and (b) are not the only approach that could be seen to be in accordance with the NEO, or in maximising economic efficiency. Further comment on an alternative approach is provided in section 2.4 below.

It is also the case that the criteria proposed in the AEMC's *Consultation Paper on the National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2014*<sup>2</sup> differ somewhat from those in the *Power of Choice Final Report*. The Consultation Paper came out before the Regulatory Proposals were lodged, but Ausgrid's regulatory submission quotes the earlier AEMC version.

There are some discrepancies in the approach taken by the businesses with the draft criteria themselves. For example, the Consultation Paper states that:

- The fee should be based on the average depreciated value of the stock of the distribution business's existing accumulation and manually read interval meters (p 51), and
- The fee for type 5 metering installations may differ from the fee for type 6 metering installations. (p 52).

However, all three of the businesses have proposed a single Exit Fee to apply to both Type 5 and Type 6 meters, despite the fact that they provide information on the annual metering charges to be applied to multiple metering configurations (6 in the case of Essential Energy and 5 in the case of Endeavour Energy). Further, those metering charges vary significantly, presumably reflecting (at least in part) the average depreciated value of each type of meter, plus administrative costs.

<sup>1</sup> AEMC. *Final Report: Power of choice review - giving consumers options in the way they use electricity*, 30 November 2012.

<sup>2</sup> AEMC, Consultation Paper: *National Electricity Amendment (Expanding Competition in Metering and Related Services) Rule 2014* and *National Electricity Retail Amendment (Expanding Competition in Metering and Related Services) Rule 2014*, 17 April 2014.

The use of a single Exit Fee is likely to be particularly problematic in Ausgrid's case, as it has installed a significant number of Type 5 meters and they are likely to be materially newer on average than their Type 6 meters.

Interestingly, where Essential Energy and Endeavour Energy report multiple metering charges, Ausgrid only calculates a single annual metering charge - for Type 6 residential installations.

Finally, we note that each of the businesses state that they have used the asset value included in the Exit Fee in adjusting their respective RAB's. This is the correct thing to do if a RAB approach is used, but the procedure by which the adjustment has been undertaken by the businesses has not been analysed. We note that the use of a single volume-weighted depreciated value across the stock of meters in the forecast of meters to be replaced (and therefore the amount by which the RAB is to be adjusted) makes the assumption that the number of each meter type that is expected to be removed is in proportion to its representation in the meter stock as a whole.

This is not an entirely unwarranted assumption (particularly in the event that a single Exit Fee is used) but could potentially be improved in the event that the use of differentiated Exit Fees is allowed - as this will effectively, through pricing, indicate the types of meters that would be more and less economically efficient for the consumer to change out.

### 2.2.2. Potential improvements to the approach used

In the first instance, we note that while the Consultation Paper states that "*the fee for type 5 metering installations may differ from the fee for type 6 metering installations*" (p 52 - emphasis added):

- The per-unit depreciated value of those two types of meters within any distribution business' meter stock is likely to be significantly different (given the likely meter costs and average age of the two types of meters in particular), and
- The Consultation Paper also states that one of the objectives of the Exit Fee is to provide "*an appropriate, clearly defined and transparent Exit Fee for accumulation or manually read interval meters [which] would be expected to encourage competition and more efficient investment in advanced metering*" (p 51).

The economic efficiency of the Exit Fee will be maximised where it provides as accurate a price signal as possible of the net value of the meter change-out. If, for example, we assume that the economic value of the service provided by the new meter to the distribution business is essentially the same whether that meter replaces a new meter or an old meter (or a type 5 meter or a type 6 meter)<sup>3</sup> then it becomes clear that efficient investment will be maximised if Retailers, Meter Coordinators and end consumers are able to identify those meters that can be replaced at least economic cost.

This reasons for the provision of separate Exit Fees wherever the costs of the meters can be identified as being materially different.

<sup>3</sup> The service provided to the distribution business by the Type 6 and Type 5 meters that are currently installed is in many cases essentially limited to the aggregate electricity consumption of the customer over a period of time (the meter reading cycle). In the case of Type 6 meters, this is the only service they provide. In the case of Type 5 meters, while they could provide more granular consumption information, that capability is often not being used as appropriate tariffs are not being deployed. As a consequence, in these cases the Type 5 meters are not providing any service in addition to that provided by a Type 6 meter.

Factors that would be expected to have the potential for making a material difference in the 'stranded asset' portion of the Exit Fee include:

- Meter type, as different types of meters are likely to have different capital costs;
- Meter type age distribution, as different types of meters may have only begun to be purchased recently, and therefore have a different age distribution, which in combination with their capital cost, may produce a very different average and standard deviation of per-unit depreciated asset value across different types of meters, and
- Meter location to the extent that installation costs (a) differ materially by location and density and (b) are capitalised<sup>4</sup>.

We note that Ausgrid's statement that

*The return on capital, return of capital as well as tax components of metering costs are distributed evenly across all tariffs by meter numbers. This approach has been determined as a fair and reasonable application, given that in the past and up until now, customers have not been given a choice in the level or type of capital investment (i.e. a choice between Type 5 or Type 6 installation).*<sup>5</sup>

may also be part of their rationale for proposing a single Exit Fee to apply across both Type 5 and Type 6 meters, it is also the case that such an approach adds another incidence in which the business' approach reduces the basis on which Retailers, Metering Providers and customers might make a choice. As discussed further below, this approach reduces allocative efficiency.

It is however recognised that the development of multiple Exit Fees entails consideration of the trade-off between the incremental gain in the allocative efficiency provided by additional categories of Exit Fees and the administrative cost of producing them and maintaining them in the market.

The Consultation Paper alludes to this when it suggests that a single Exit Fee per meter type may be appropriate for the sake of "*simplicity and administrative ease, as an alternative to attempting to determine the age of the actual meter at each individual consumer's premise*" (p 52). It is correct to surmise that the administrative burden of setting an Exit Fee based on the specific characteristics of each meter may entail an undue administrative burden, however:

- There may be valuable allocative efficiency gains available from at least some differentiation of Exit Fees below the meter type level (and certainly below the all-meter-types level currently proposed in the business' proposals), and
- The administrative cost of establishing differentiated Exit Fees should not be particularly high as the businesses have all of the information required to do so, and therefore
- It would be worthwhile assessing the different Exit Fees that would result if they were produced by meter type, meter age cohort, and meter location. The number of age cohorts could be selected based on the age distribution of the existing meter stock, and the ultimate number of Exit Fees guided by the materiality of the difference between the fees that would pertain with and without any additional category under consideration. Given the level of the Exit Fees proposed in the business' proposal a materiality level in the range of approximately 10% to 20% of the non-differentiated meter type Exit Fee would seem to be appropriate to consider.

<sup>4</sup> It is our understanding that meter installation in NSW is undertaken on an outsourced basis, and accordingly those direct installation costs are unlikely to have been capitalised.

<sup>5</sup> Ausgrid, *Attachment 8.15 - Type 5 and 6 metering services proposal*, 2014, p 23.



### 2.2.3. Application to Ausgrid's Type 5 meters

Meters are installed to provide specific functionality. Type 6 meters provide very basic functionality - primarily accumulated electricity consumption. This information is used essentially only in billing and certain analyses of aggregate consumption (for example, trend forecasting). Type 5 meters, by contrast, provide the capability to provide interval consumption data and other information.

There has not been anything in the Rules or relevant regulation or legislation that has directed the NSW distribution businesses to install Type 5 meters in residential and small business facilities<sup>6</sup>. In the absence of such direction, there remain two likely reasons why the distribution businesses would have decided to install Type 5 metering:

- To reduce metering costs, or
- To provide a more cost-reflective price signal and thereby encourage customers to change their consumption patterns, which would thereby reduce system costs.

We note that the former is a cost entirely associated with the provision of a metering service. Where a Type 5 meter can be installed at a lower cost than the metering installation that would otherwise be required<sup>7</sup>, recovery of the full (though depreciated) cost of the meter should be seen as consistent with the Depreciated Replacement Cost cited in the AEMC's Consultation Paper.

By contrast, where the Type 5 meter is installed to provide a more cost-reflective price signal, the additional benefits that accrue from the installation of that Type 5 meter (relative to a Type 6 meter) are likely to be categorised as being network benefits. In this scenario, it could be argued that the amount by which the cost of the Type 5 meter exceeds the cost of a Type 6 meter should be a cost of providing Standard Control Services, and therefore more appropriately recovered through DUoS charges. We note that a large number of the Type 5 meters deployed by Ausgrid were accompanied by the assignment of the customer to a TOU tariff.

It is not known exactly what proportion of the Type 5 meters installed by Ausgrid and Endeavour Energy were installed to support TOU pricing, and what proportion were installed because they were the lowest cost option for providing the required metering service<sup>8</sup>.

## 2.3. Review of the Exit Fees as presented in the businesses' Regulatory Proposals

### 2.3.1. Overview of the proposed Exit Fees and their composition

Table 1 on the following page presents an overview of the Exit Fees and annual meter charges proposed by the three NSW distribution businesses in their Regulatory Proposals. Items of note include:

- As discussed above, each of the distribution businesses has proposed a single Exit Fee despite the fact that they provide a number of different metering configurations with materially different costs as reflected in the annual meter charges proposed for them, and

<sup>6</sup> This is in contrast to Victoria where the installation of Type 6 meters with communications was mandated by the state government.

<sup>7</sup> As was cited by Ausgrid in its submission to a previous regulatory determination in regard to situations in which a two-meter installation needed to be replaced.

<sup>8</sup> In some cases, Type 5 meters may have been installed via trials or demonstration programs. Such costs would most likely be considered to be Standard Control Services (unless they were undertaken strictly to assess the ability of the meters to accurately record aggregate consumption).



Table 1: Overview of proposed Exit Fees and metering charges

	Ausgrid <sup>9</sup> (nominal dollars)					Essential Energy <sup>10</sup> (real FY14 dollars)					Endeavour Energy <sup>11</sup> (nominal dollars)					
	FY15 <sup>12</sup>	FY16	FY17	FY18	FY19	FY16	FY17	FY18	FY19	FY15 <sup>7</sup>	FY16	FY17	FY18	FY19		
Exit fees as proposed in Regulatory Proposals																
Admin costs	36.00	37.47	39.20	41.01	42.89	54.34	54.99	56.13	57.28	50.49	51.76	53.05	54.38	55.74		
Stranded asset costs	160.64	157.76	158.68	160.48	161.78	77.23	69.99	59.93	51.93	16.89	13.98	10.95	7.69	4.08		
Total Exit Fee	196.64	195.24	197.89	201.49	204.67	131.57	124.98	116.06	109.21	67.39	65.74	64.00	62.06	59.81		
Annual meter charges as proposed in Regulatory Proposals																
Type 6 residential	34.71					Res Anytime	48.74	50.94	51.93	55.87	Anytime	25.16	26.2	27.12	27.15	29.15
						Res TOU	57.02	59.24	60.29	64.26	Type 6	46.85	48.54	50.68	51.17	54.09
						Sm Bus Anytime	48.74	50.94	51.93	55.87	Type 5	175.72	180.27	188.93	191.31	198.82
						Sm Bus TOU	57.02	59.24	60.29	64.26	Controlled load	11.35	12.09	12.33	12.16	13.68
						Controlled load	18.79	19.79	20.21	21.99	Solar	11.35	12.09	12.33	12.16	13.68
						Solar (gross)	54.2	56.23	57.21	60.84						
Proposed Exit Fee as a multiple of proposed annual metering charge <sup>13</sup>																
Type 6 residential	5.62					Res Anytime	2.70	2.45	2.23	1.95	Anytime	2.68	2.51	2.36	2.29	2.05
						Res TOU	2.31	2.11	1.93	1.70	Type 6	1.44	1.35	1.26	1.21	1.11
						Sm Bus Anytime	2.70	2.45	2.23	1.95	Type 5	0.38	0.36	0.34	0.32	0.30
						Sm Bus TOU	2.31	2.11	1.93	1.70	Anytime & CL	1.85	1.72	1.62	1.58	1.40
						Res Anytime & CL	1.95	1.77	1.61	1.40	Anytime & Solar	1.85	1.72	1.62	1.58	1.40
						Res Anytime & Solar	1.28	1.17	1.06	0.94						

<sup>9</sup> Ausgrid, *Regulatory Proposal Attachment 8.15*, p 26.

<sup>10</sup> Essential Energy, *Regulatory Proposal Attachment 8.5*, pp 11 & 13.

<sup>11</sup> Endeavour Energy, *Regulatory Proposal*, p 143.

<sup>12</sup> Indicative only.

<sup>13</sup> Calculated from the figures above.

- The 'stranded asset cost' portion of the Exit Fees proposed by the three distribution businesses varies significantly. While this is likely to be a reflection of the nature of their meter stocks, the differences are striking. Ausgrid's stranded asset cost figure is between twice and three times that of Essential Energy and up to ten times the figure quoted by Endeavour Energy. Whilst this may be a reflection of the meter stocks (both types and age profiles) of the three businesses, assurances should at least be sought that a consistent approach to the calculation of these stranded asset costs has been used across the businesses;
- Although the administrative costs quoted by the three distribution businesses vary less than the stranded asset costs, it is worth noting that FY16 administrative cost portion of the Exit Fees proposed by Endeavour Energy and Essential Energy are approximately 140% to 150% of the level proposed by Ausgrid. This is of concern, given that the activities associated with these costs - the "*efficient and reasonable costs associated with transferring the customer to another Metering Coordinator*"<sup>14</sup> - would presumably entail only changing information in the business' systems, probably limited to a change in information about the entity that is responsible for the meter, the identity of the Metering Coordinator and enough information about the type of meter to enable verification that it is appropriate for the application and tariff being applied;
- Based on this it might be assumed that the administrative costs would vary with the time required to process a meter change. However, the times cited by the businesses do not conform to this expectation, as shown in the table below:

Table 2: Comparison of businesses' time required to process a meter change and administrative costs

Distribution Business	Amount of time reported to process a meter change (FTE hr) & as % of Ausgrid	Administrative costs in proposed Exit Fee (nominal \$ FY16) & as % of Ausgrid
Endeavour Energy	0.33 (82.5%)	\$51.76 (138.1%)
Ausgrid	0.4	\$37.47
Essential Energy	0.5 (125.0%)	\$57.09 <sup>15</sup> (152.4%)

Source: OGW calculations of information provided by the businesses

As noted above, the rationale for these differences is not immediately obvious and would profit from additional explanation.

More generally, assurance should be sought that a consistent approach to the calculation of the 'efficient' administrative costs has been used across the businesses. Of particular concern in this regard would be whether and to what extent any of the businesses have included new system-related capital costs required to record the Metering Coordinator associated with each meter. It also seems at odds with the reforms and associated creation of Networks NSW to harmonise and minimise administration costs;

14 AEMC, Consultation Paper, p 52.

15 Essential Energy's FY16 administrative costs in FY14 dollars as shown in Table 1 escalated to FY16 nominal dollars at 2.5% per year.

- The Exit Fees proposed by the businesses represent very different levels in terms of the multiples they represent of annual meter charges. We note that the Consultation Paper states that SCER “proposes that the AER should consider whether a cap on fees would be appropriate and, if so, the level of the cap” (p 52). The cap is proposed as a means of providing “retailers, consumers and other parties with certainty that exit fees would not be unreasonably high, and confidence to invest in a new meter” (p 52).

In its Regulatory Proposal Ausgrid cites the AEMC’s suggestion in its *Power of Choice Final Report* that Exit Fees be capped at no more than 3 times the annual meter charge. However, the Exit Fee it proposes for FY16 (\$195.24) is actually 5.62 times the annual meter charge projected for a Type 6 meter in that year. By contrast, as shown in Table 1 above, none of the Exit Fees proposed by the other businesses exceed 3 times the annual meter charge. Despite this, the wide variability in the multiples shown for the various metering configurations provided by Essential Energy and Endeavour Energy suggests that significant improvement in their Exit Prices as a price signal (and therefore their allocative efficiency) could be achieved by considering different Exit Fees for different meter types;

- In one case - that of Essential Energy in regard to single phase accumulation meters - the Exit Fee is higher than new cost for the meter<sup>16</sup>. There may be reasons for this, but they should be made explicit.

### 2.3.2. Overhead costs included in the Exit Fees

There are several specific concerns regarding the how overheads are used in developing the Exit Fees:

- The administrative costs may include overheads that may not be justified - The businesses have included overheads in their development of administrative costs, and it is not immediately clear that all of the overhead head costs claimed are appropriate.

Endeavour Energy applies an ‘Average Network and Corporate Overhead’ factor of 205% to the labour cost of completing the required administrative work (\$25.25, which is a cost of 0.33 hours of administrative labour at \$75.76/hr in FY16 nominal dollars)<sup>17</sup>. That factor is arrived at by considering all of the cost categories included in the Recoverable Opex Detail tab of its *Metering and model and prices spreadsheet*<sup>18</sup>.

It is worth noting that Endeavour’s direct administrative cost of \$25.25 equates to 67.4% of the administrative cost cited by Ausgrid, which is much more consistent with the relativity of the amount of labour time they cite (with Endeavour’s requirement being 82.5% of Ausgrid’s). The fact that Ausgrid describes the recoverable administrative costs as those that are required to “change records to reflect the changed status, the return of the meter and the processing costs of relaying this information”<sup>19</sup> also contributes to the possibility that the difference in the costs is a product of how overheads are treated;

<sup>16</sup> Table 6 of Essential Energy, *Regulatory Proposal Attachment 8.5*, shows the up-front charge for a customer initiated installation of a single phase accumulation meter as being \$35.51 as compared to an annual metering charge of \$48.74 (both real FY14\$). Accompanying text also states that this charge is in addition to any costs for installation.

<sup>17</sup> See the Exit Charges tab of the spreadsheet entitled *Endeavour Energy - 0.17 - Metering model and prices - May 2014*.

<sup>18</sup> Endeavour Energy, *Attachment 8.7\_Charges for type 5 and 6 metering services - 2014*.

<sup>19</sup> Ausgrid, *Attachment 8.15 Type 5 & 6 metering services proposal*, p 25.

- There are similar concerns with regard to the treatment of overheads in the 'stranded asset' portion of the Exit Fees. These primarily involve the inclusion of shared costs that are largely indivisible - that is, they are not particularly sensitive to a change in the number of meters deployed by the distribution business unless the change in the number of meters is a quite large proportion of the total original number of meters. A good example of this is the following statement by Ausgrid:

*We have distributed corporate overhead costs (associated with furniture, plant, property, shared IT etc.) evenly across all NMI's. The cost per NMI is calculated by dividing the corporate overhead associated with metering by the combined total number of all NMI categories.<sup>20</sup>*

- More generally we note that what is fundamentally at issue here is how best to recover fixed costs. Economic efficiency (and therefore the NEO) is best served where fixed costs are recovered from those customers/services that have the most inelastic demand (i.e., through Ramsey pricing principles). This would result in the recovery of these fixed costs being achieved in a way that least distorts the consumption of services (i.e., in a way that minimises the deviation in consumption from levels that would have occurred had charges been based on the incremental cost of supply).

- To do so in the case of allocating fixed 'Corporate Costs' to Exit Fees (e.g., a portion of the costs Finance, HR, etc.) requires a comparison of the elasticity of demand for Standard Control Services (or particular tariffs for particular customer classes provided with Standard Control Services) versus the elasticity of demand for Exit Fees.

It is therefore reasonable to argue that these fixed costs should be allocated back into Standard Control Services and recovered via increases in fixed (DUoS) charges to customers. Assuming that this increase in fixed charges does not lead to the recovery of the required revenue from a particular customer class at a level that exceeds the standalone cost of supply for that customer class (which is almost certain to be the case), the recovery of that revenue will, by definition, be recovered from the most inelastic product (because subject to not exceeding the standalone cost test, increasing fixed charges has no impact on the consumption of services, whereas the recovery via an exit fee would clearly have an impact on the consumption of that service, and therefore, reduce allocative efficiency);

- However, if there are fixed 'metering' costs (i.e., if the overheads being allocated to Exit Fees relate specifically to the provision of metering services, rather than Standard Control Services), then any Ramsey pricing approach would effectively need to compare the elasticity of demand for Metering Services, versus the elasticity of demand for Exit Fees.

In this case it is difficult to argue whether demand for one of these products is more or less inelastic than the demand for the other. Clearly, allocating all of these costs fully to the Metering Services provided by distribution businesses will reduce the Exit Fee whilst also increasing the costs that the distribution business needs to recover from those meters it continues to provide. This could be seen as overly advantaging competitive meter providers.

On the other hand, allocating these costs to the Exit Fee increases the cost of choosing a competitively supplied meter even though that increase in cost exceeds the marginal cost associated with the supply of that service.

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Ausgrid, *Attachment 8.15 - Type 5 and 6 metering services proposal*, 2014, p 23.

In the absence of any quantitative information on the elasticity of demand for Metering Services versus the elasticity of demand for Exit Fees, therefore, the best course might be to split the allocation of these costs between Metering Services and Exit Fees.

## 2.4. An alternative approach for setting Exit Fees

Subject to one caveat (which is discussed below), economic theory would lead one to base the value of a distribution business' (DB) metering assets on their Optimised Deprival Value (ODV).

ODV is the lesser of the:

- NPV of the revenue stream (i.e., future revenues) generated by the use of that asset<sup>21</sup>, and
- Depreciated Optimised Replacement Cost (DORC) value of that asset.

This is based on the premise that:

- A person will not pay an amount for an asset based on a DORC valuation, if that asset generates an income or set of benefits (in NPV terms) that is *less* than that DORC valuation, *conversely*
- A person would not pay the NPV of revenues that were expected to be generated from an asset, if in fact they could replicate that asset (e.g., build the same asset, or build an asset that delivers the same functionality/services) at a lower cost, whilst still achieving an NPV of revenues that are higher than that cost (effectively a stand-alone cost test).

This is why ODV is the generally accepted method for valuing assets in economics, and also in competitive markets<sup>22</sup>. If an asset value in a competitive market is not supported by future cashflows (or benefits stream) then it is effectively written down (impaired value) which effectively passes cashflow, and largely technology risk, to the investor.

Therefore, another way of thinking about this asset valuation question as metrology moves to being a competitive service, particularly when the future benefits of an asset are not directly able to be monetised (as may be the case for metrology services), is: *what is the opportunity cost to an existing meter owner, if they were deprived of the services and functionality of that meter.*

One way of assessing this opportunity cost is to estimate the cost to the distribution business of achieving the same functionality/services provided by the meter, via other means. In NSW, the only services that the distribution businesses would be deprived of is the data from the meter that is required to undertake network billing<sup>23</sup>. If this data could be generated through other means (e.g., purchased from someone else), then subject to our one caveat (discussed below), this would represent the opportunity cost to the NSW distribution businesses, and therefore, the value of their current meters.

<sup>21</sup> Or alternatively, the 'scrap value' of that asset, if this is in fact higher than the NPV of future cashflows derived from utilising that asset.

<sup>22</sup> For the purposes of setting regulatory asset values using a building block approach, the ODV approach can be problematic, because there is a circularity issue in using NPV to measure the economic capital value. NPV calculation requires a forecast of cashflows based on return on and of capital (and opex), which in turn requires a starting asset value when using a building block approach.

<sup>23</sup> This can be contrasted with Victoria, which has AMI meters that provide distribution businesses with a broader suite of services/functionality, such as remote disconnection/reconnection and remote reading.

A hypothetical example of this would be if a Retailer replaced an accumulation meter with an AMI meter (as part of the competitive arrangements for metering that are currently being considered by the AEMC), and then sold the same metrology services back to the distribution businesses for say \$10 (in NPV terms over the remaining life of the original meter), yet the depreciated cost of the accumulation meter that was replaced was \$20.

In this very simple scenario, the **value of the meter would be \$10**, not some measure of its depreciated value (e.g., \$20). It must be noted that adopting such an approach would allocate technology risk to the NSW distribution businesses (i.e., the risk that a new technology or service provider comes along in the future, and provides the same services as their existing asset, but at a lower cost). This is effectively a “market” test of the real meter value - could the market provide the service at a lower NPV.

This approach also argues that a Type 5 meter where it is supplying the same functionality/service as a Type 6 meter has no more value than a Type 6 meter.

#### 2.4.1. Caveat

The only caveat to the above is that the methodology adopted needs to have regard for the circumstances underpinning the original installation of those meters. In particular, was the installation of *that type of meter at that time* mandatory or discretionary? If the installation of that meter type was mandatory, such as was the case in Victoria with the AMI meters, then it is *not* an efficient allocation of risk for those DBs to face technology risk (as the act of mandating means that that investment was effectively beyond the control of the distribution business, and therefore there would be no efficiency benefit from allocating future technology or market risk to the distribution business). However, if the DB in fact *elected* to install an accumulation meter over other alternative meter types (e.g., it could have installed a meter with other functionality, but instead choose to install an accumulation meter), then it could be argued that DBs should bear this technology risk (bear the risk that someone comes along in the future and provides the same services provided by the accumulation meter, but at a lower cost). If this is the case in NSW, then the methodology outlined above for establishing the Exit Fee (which, to recap, would lead to the \$10 value being established in our simple example) would be appropriate.

#### 2.4.2. Conclusion

Theoretically, it could be argued that the methodology that should be used to calculate the Exit Fee should not be based on some measure of the unrecovered value of the meter, but rather the opportunity cost to the distribution business of the services/functionality provided by the accumulation meter that is replaced, one form of which is the cost of procuring those services/functionalities from another source. Before going down this path, however, the following key questions would need to be answered:

- What is the opportunity cost to the distribution businesses of obtaining the services/functionality of the meter from a different ‘source’ (e.g., a Retailer who replaced an accumulation meter with an AMI meter), and is this opportunity cost lower than the unrecovered value? This “market” test needs to be seriously considered by the Regulator, and
- Was the original decision to invest in that accumulation meter mandated, or under the control of the distribution business, as this will impact on whether technology risk should be allocated to the distribution business (via how the Exit Fee is calculated)?

As an aside, if it is not currently feasible to establish the opportunity cost to the distribution businesses of obtaining the services/functionality of their existing accumulation meters from a different 'source', then the Retailers may want to consider proposing to the AER that there be some flexibility in how the Exit Fee is established in the future - in effect some form of transitional approach to a fully competitive market.

This may, for example, provide for the Exit Fee to reflect the *lessor of* some measure of the unrecovered value of the accumulation meter, and the fee that has been negotiated between Retailers and distribution business for the provision of equivalent services/functionality back to the distribution business for the remaining life of the meter. Subject to accepting that metering technology risk should be allocated to the businesses, this approach better reflects the economic principles that underpin the National Electricity Objective, as well as the outcomes that would occur in a perfectly competitive market.

### 3. Operating cost review

#### 3.1. Introduction

The objective of this section of the report is to highlight the key aspects of the NSW distribution businesses operating expenditure forecasts that we consider may not be consistent with the National Electricity Rules (Rules).

The detailed issues that are discussed in this report include:

- Issues common across the businesses
  - TSA contract dis-synergies costs.
  - Base year - variation by volume;
  - Base year - historical average;
  - Enterprise Bargaining Agreement and labour cost escalators
  - Driver for inspection - Ausgrid and Endeavour Energy
  - Actuarial adjustment to base year
- Endeavour Energy issues
  - Vegetation management
  - Increase in emergency response expenditure
  - Regulatory re-set costs
- Ausgrid issues
  - Private mains
  - Asbestos Containing Materials
- Essential Energy issues
  - Recovery of 'Stranded' Opex Costs resulting from reduced capex program

#### 3.2. Overall comments on forecast operating expenditure methodology

All of the NSW distribution business have adopted broadly similar approaches to developing their operating expenditure forecasts for the forthcoming regulatory control period. We will discuss the detailed aspects of their forecasts in the following sections, however we wanted to specifically comment upon two aspects of their general approach.



These are whether their:

- 2012/13 actual expenditure should be assumed to be efficient, and
- Efficiency improvement programs should be assumed to be able to be 'self-funded'.

### 3.3. Use of 2012/13 as the base year

All of the businesses have used their actual expenditure in 2012/13 as their base year ('base year approach'), although, in some circumstances this assumption has been relaxed (we discuss these adjustments in the following sections).

The assumption that the 4<sup>th</sup> year (2012/13) of the current regulatory control period reflects the efficient costs of providing standard control services is consistent with the approach that:

- Most regulated businesses have adopted in recent regulatory review processes, and
- Aligns with the broader regulatory framework, which is premised on providing incentives for businesses to reveal their efficient costs for providing existing levels of service.

The key mechanism that supports this is the Efficiency Benefit Sharing Scheme (EBSS), which rewards (and penalises) incremental gains (and reductions) in efficiency over the regulatory control period. The scheme is both:

- Symmetrical (equally rewards gains and losses), and
- Continuous (the incentive is the same across each of the years of the regulatory control period).

Conceptually, we agree with the NSW distribution businesses use of the base year approach, on the proviso that:

- Each business has demonstrated a willingness to respond to the underlying incentive to reveal their efficient costs (in particular, in the base year), and
- The results of any benchmarking analysis does not demonstrably indicate that in aggregate, or at a category level, a business is inefficient in the base year.

#### Have businesses responded to the incentives under the regulatory framework?

The following table highlights the extent to which businesses have reduced their operating expenditure over the current regulatory control period, relative to their original allowance.

Table 3: Comparison of opex (\$m, 2013/14)

Distribution Business	2009/10	2010/11	2011/12	2012/13	2013/14
Ausgrid	25.5	-0.5	47.8	-87.5	-18.0
Endeavour	-54.7	-42.3	-40.7	-72.3	-26.7
Essential <sup>24</sup>	-35.6	-30.3	50	14.56	NA

Source: The Regulatory Proposals of Ausgrid, Endeavour and Essential Energy

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Essential Energy's reflects the difference between their operating expenditure allowance and their actual operating expenditure, as used in the calculation of their efficiency carryover amounts in Attachment 4.3

As can be seen from the table above, each of the businesses has out-performed their operating expenditure allowances in totality over the entire regulatory control period.

Based on the information provided in their regulatory submission, a significant portion (around 58%) of Endeavour Energy's overall operating cost reduction is related to lower vegetation management costs than were allowed for. This appears to be predominately driven by reduced conformance with their own internal standards.

We also note that Ausgrid's overall efficiency improvement is almost exclusively driven by an \$87.5m reduction in 2012/13 relative to its original allowance. This represented an incremental reduction of \$124.3m (or 19.26%) in expenditure from 2011/12 levels. Ausgrid notes that '*the Network Reform Process implemented under industry reform has enabled Ausgrid to make significant reductions in opex over the last 2 years of the period*<sup>25</sup>'. Prior to 2012/13, Ausgrid's operating expenditure was materially higher than its original allowance, which, prima facie, may indicate that its performance was impacted by events that were not originally forecast (including exogenous events), or that its actual performance over those years was not predominately driven by the underlying incentives in the regulatory framework to reveal efficiencies.

In considering this, we note a number of Ausgrid's statements in their Regulatory Proposal describing the efficiency savings achieved in 2012/13 and 2013/14, including that<sup>26</sup>:

*The reform process has elicited significant **cultural change** at Ausgrid. We now have **more effective cost controls in place with a renewed focus on micro efficiency reforms** in areas where there was room for cost savings such as:*

- A review of work practices to ensure less overtime is needed to perform core functions. The total overtime expenditure for Ausgrid as a whole fell from approximately \$96 million in 2011/12 to a forecast of approximately \$40 million in 2013/14.*
- Reductions in travel expenses by reducing flight and taxi usage. **[emphasis added]***

We also note that in Attachment 1.01, Ausgrid provides further information on these items, including<sup>27</sup>:

*Industry reform provided an opportunity to review work practices and address historical institutional rigidities within each of our businesses. An identified area of potential saving was reducing the number of overtime hours, which in turn reduces the average labour cost of undertake capital and operating activities*

*The key to improvements in discretionary expenditure has been policy changes supported by a focus on specific operational opportunities. For instance, we have reduced the cost of Ausgrid flights by close to 50% between 2012 and 2013*

<sup>25</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 49

<sup>26</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 50

<sup>27</sup> Networks NSW, *Attachment 1.01 - Delivering efficiencies for our Customers*, May 2014, pages 20-21

Whilst the above efficiencies are obviously good for customers, our initial observation is that neither of the outcomes highlighted above (which both appear to be material) appear to be explicitly linked to any 'structural change' (e.g., a scale and scope efficiency driven by the aggregation of functions as part of the Network Reform Process)<sup>28</sup> therefore, everything else being equal, one might assume that at least some of these efficiency gains may have been able to have been achieved earlier in the current regulatory control period (or even in previous regulatory control periods).

If this is the case, it also begs the question as to whether the large reductions in Ausgrid's expenditure resulting from the Network Reform Process move Ausgrid's operating expenditure *to* efficient levels in 2012/13, or they simply represent a large move *towards* efficient levels (i.e., they are not yet at the efficient frontier). In these circumstances, it is difficult to clearly make the case based on the evidence available that they have not responded to the underlying incentives to reveal more efficient costs in the 2012/13 year - whether these are in fact consistent with a prudent and efficient service provider obviously needs to be a focus of the AER's as part of the review process.

### Results of benchmarking analysis presented by the businesses

Each of the businesses have presented some high level benchmarking analysis in attachments to their regulatory proposals. This analysis indicates that:

- Ausgrid<sup>29</sup> has the:
  - Second highest operating cost per km in 2013, but the second lowest operating expenditure per customer in 2013, and
  - Second highest maintenance operating expenditure per km in 2013, and the third highest operations expenditure per customer in 2013.
- Essential Energy<sup>30</sup> has the:
  - Lowest operating cost per km in 2013, but the third highest operating expenditure per customer in 2013, and
  - Second lowest maintenance operating expenditure per km in 2013, and the lowest operations expenditure per customer in 2013.
- Endeavour Energy<sup>31</sup> has the:
  - Third highest operating cost per km in 2013, but the third lowest operating expenditure per customer in 2013, and
  - Third lowest maintenance expenditure per km in 2013, but the third highest operations operating expenditure per customer in 2013.

<sup>28</sup> We do note the reference to 'industry reform provided an opportunity to review work practices', although it is unclear to us why the creation of Networks NSW would have been a pre-requisite to unlocking these efficiency improvements.

<sup>29</sup> Ausgrid, *Attachment 5.33 - Addressing the benchmarking factor for capex and opex*, May 2014

<sup>30</sup> Essential Energy, *Attachment 5.4 - Addressing the Benchmarking Factor*

<sup>31</sup> Endeavour Energy, *Addressing the benchmarking factor for capex and opex*, May 2014

Due to time constraints, we have not been able to undertake a ‘deep dive’ analysis into the benchmarking results presented by the business in their Regulatory Proposals, nor have we attempted to undertake any of our own benchmarking analysis. However, taking the results presented by the businesses on face value, there is nothing that would clearly stand out to us as being demonstrable evidence that any of the business were, *in FY 2013*, clearly inefficient. In saying this, we note that the analysis does not account for numerous factors such as topography, weather, legacy network design, that may influence the aforementioned metrics, and which therefore would need to be accounted for before analysis such as this could be truly relied upon.

We note that section 6.5.6 (e)(4) of the Rules requires the AER to have regard to ‘*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*’. In complying with this component of the Rules, we know that the AER will thoroughly investigate the benchmarking analysis presented by the businesses in their regulatory proposal, and undertake their own analysis. We note in particular that where category analysis indicates a business may not be at or near the efficient frontier, the AER should seek to establish what differentiates that business from the frontier business in that category (including considering factors such as topography, weather, legacy network design, etc. factors), so that it can more clearly determine whether the difference relates to exogenous or endogenous variables.

### 3.4. Self-funding efficiency improvements

We note that each business’ operating expenditure forecast reflects the:

- Cost of undertaking programs that are designed to deliver broader productivity improvements, and
- Reductions in operating expenditure that result from the implementation of those programs.

It is our understanding that the AER’s previous regulatory decisions have reflected a view that the current regulatory model encourages the self-funding of efficiency improvements, as efficiency improvements can be captured through the EBSS. For example, in its Victorian Draft Decision, the AER stated<sup>32</sup>:

*that any business process improvements which result in lower costs will be self financing as the net costs should be expected to be less than those reflected in the revenue requirement*

They also stated that<sup>33</sup>:

*the regulatory framework provides incentives for DNSPs to pursue such efficiencies, funded through self financing arrangements, and retain the benefits for a period consistent with the EBSS. The benefits of those efficiencies are shared with customers over time.*

On face value, this precedence would indicate that the AER is likely to err on the side of rejecting the NSW distribution businesses forecast operating expenditure associated with programs that are designed to deliver future productivity improvements (as well as the forecast operating expenditure savings associated with those programs).

<sup>32</sup> AER, *Draft decision, Victorian electricity distribution network service providers Distribution determination 2011-2015, Appendices*, June 2010, p. 206

<sup>33</sup> *Ibid*, p. 184

That said, whilst we agree with the self-financing concept in principle, we note that the incentives for businesses to self-finance efficiency improvements may be more complex than simply relying on the EBSS, which we note leads to around a 30:70 split of benefits (in NPV terms) between the business undertaking the initiative and its customers. Rather, whether businesses will or will not self-finance expenditure will be a function of whether the financial benefit that they accrue under the EBSS (which, again represents only around 30% of the entire benefit in NPV terms), exceeds the costs of undertaking the program. Therefore, where a program is more 'marginal', then it may not be able to be self-financed by a business under the EBSS, even if the full economic benefits exceed the economic costs (i.e., it is an efficient use of resources, and therefore, would meet the requirements of the National Electricity Objective). That said, this issue does not appear to be relevant in this situation, given the efficiency programs that the NSW distribution businesses are offering up appear to reflect material net benefits within the forecast regulatory control period.<sup>34</sup> In this situation, the NSW distribution businesses are offering up the benefits of the proposed efficiency savings in advance, as opposed to accruing them through the workings of the EBSS. Assuming these savings come to fruition (and the costs are accurately forecast), this approach results in 100% of the savings being passed through to customers, instead of the 70% in NPV terms that would occur if the NSW distribution business self-funded those efficiency programs under the EBSS.

In this circumstance, we believe that the distribution businesses proposed approach is consistent with the requirements of the National Electricity Objective. This approach is clearly in the long term interests of customers, and moreover, it:

- Mitigates the need for prices to deviate from costs (which occurs as a result of the operation of the EBSS), which may negatively impact on the '*efficient use of*' electricity services, and
- Does not compromise the incentive for the NSW distribution businesses to continue to seek out incremental improvements in efficiency (i.e. those additional to what has been forecast) over the forthcoming regulatory control period, which is in the '*long term interests of consumers.*'

### 3.5. Issues common across businesses

#### 3.5.1. TSA contract dis-synergies costs

Each business has incorporated the costs of retail 'dis-synergy' costs into their operating expenditure forecasts. Broadly, this accounts for the fact that these businesses were previously integrated businesses providing both distribution services (as a distribution network service provider) and non-distribution services (including a retail business), and these services used integrated systems and processes while maintaining ring-fencing arrangements.

The timing for the cessation of the provision of these services differs across each of the businesses:

- Endeavour Energy - ceased 30<sup>th</sup> April 2013<sup>35</sup>
- Essential Energy - ceased 3 January 2014<sup>36</sup>

<sup>34</sup> For example, Ausgrid state in on page 60 of their proposal that the benefits of their efficiency programs over the forthcoming regulatory control period are expected to be \$163.9m, relative to \$51.8m in costs, and it delivers positive benefits in each year of the forthcoming regulatory control period.

<sup>35</sup> Endeavour Energy, Regulatory Proposal to The Australian Energy Regulator, 1 July 2015 - 30 June 2019, page 77

<sup>36</sup> Essential Energy, Regulatory Proposal 1 July 2014 to 30 June 2019, 31 May 2014, page 76

■ Ausgrid - anticipated to cease in November 2014<sup>37</sup>

Ausgrid explains the impact of this in its Regulatory Proposal as such<sup>38</sup>:

*Upon termination of the TSA, Ausgrid's operational and **fixed support cost** of providing standard control services will increase due to the loss of scale and scope of being an integrated retail/network business. The cessation of the TSA has direct impact on operational areas of the NEM data operations and the emergency contact centre as well as support areas such as, finance, human resources, IT, property and management.*

*These 'loss of synergy' costs have been factored into the forecast opex for the 2014-19 period. The AER recognised this potential 'loss of synergy' in its distribution determination for Ausgrid for the 2009-14 period. **[Emphasis added]***

Ausgrid also noted that in accepting the 'Retail project event' (i.e. sale of the retail business) as a nominated pass through event, the AER previously stated that<sup>39</sup>:

*If the NSW electricity retail businesses are privatised the DNSP's cost of providing direct control services may increase due to loss of synergies*

All businesses appear to be, to some degree, forecasting reductions in these retail 'dis-synergy' costs over time.

Firstly, conceptually, we question whether the full 'retail dis-synergy' costs should in fact be allowed to be recovered at all under the Rules (NOTE: by 'full retail dis-synergy' costs, we mean the amount that would need to be added to a business' existing base year costs, in order to allow it to recover their current cost of supply<sup>40</sup>).

In assessing this, it is worthwhile considering what might happen in a competitive market, if a business set itself up to provide multiple (two) services to various customers (which is effectively what the NSW businesses did, when they provided both distribution and retail services). In practice, such a business would be able to capture the economies of scope associated with providing those two services, because, *ceteris paribus*, its costs would be lower, but it would be able to sell those two services at the prevailing market price. Importantly, if the marginal provider of services in the two markets was a standalone service provider, then the market clearing price would reflect the cost structure of a standalone service provider, operating only in that market.

In this situation, if one of the markets were to dissipate for the service provider, that service provider would not simply be able to recover the full amount of its shared costs from the remaining market, *if those costs exceeded that of marginal standalone service provider*, rather, the amount that it could recover would be capped at the costs to the marginal standalone service provider.

<sup>37</sup> Ausgrid, Regulatory Proposal 1 July 2014 to 30 June 2019, 30 May 2014, page 56

<sup>38</sup> Ibid, page 56-57

<sup>39</sup> Ibid

<sup>40</sup> This is our understanding of the businesses forecasting methodology.

If we overlay the above concept on the situation that the NSW distribution businesses face, then the retail dis-synergy costs that they would be able to add to their base year costs would not simply reflect the amount that they would have otherwise recovered via the TSA if they continued to provide those services to the Retailers, rather, they would reflect the additional costs that, when added to each business' base year costs, would lead to an operating expenditure allowance that would reflect the efficient costs that would be incurred by an efficient *standalone business*. We believe that this is consistent with the Rules, in particular, Section 6.5.6 (c) of the Rules require that the prudent and efficient costs reflect the efficient costs of achieving the operating expenditure objectives, and the operating expenditure objectives are underpinned by the need to provide *standard control services*. Importantly, the Rules do not necessarily rely on the use of that individual business' cost structure to determine this - rather, it is the cost structure of a prudent and efficient business. Furthermore, the 'base year' (revealed cost) approach cannot be relied upon in this situation, as there has been a change in the circumstances faced by the distribution businesses.

With reference to Ausgrid's comments above, this could mean that despite the fact that its '*fixed support cost of providing standard control services will increase*', the amount that it should be able to recover under the Rules should only reflect the fixed support costs of a prudent and efficient standalone service provider, not what Ausgrid's standalone costs (as a former provider of multiple services) are. Furthermore, the fact that Ausgrid (and all of the distribution businesses for that matter) have forecast that their costs will, over time, reduce to new, more efficient levels, is prima facie evidence that their individual standalone costs are, upon expiry of the TSA, not in fact consistent with the efficient costs of a standalone business (if they did, they would not be proposing to reduce these costs at all).

In addition to the aforementioned conceptual discussion, we would observe at a more detailed level that:

- A portion of Endeavour Energy's dis-synergy costs should be reflected in its 2012/13 base year (because their TSA ceased on the 30th April 2013), therefore, everything else being equal, one would expect their forecast of the incremental impact of this issue to be lower than the other businesses; and
- By the end of 2016/17, both Essential Energy and Ausgrid appear to have reduced the financial impact of this issue to customers to zero (reflecting a move to efficient levels). It is unclear, from the information provided in their Regulatory Proposal, whether Endeavour Energy has also adopted a similar assumption.

Overall, we would expect that the AER will pay particular attention to this issue as part of its review of the businesses operating expenditure forecasts, given the magnitude of the proposed cost increases above base year levels, and the complex nature of the assessment of the costs, against the requirements of the Rules. In saying this, we reiterate that this assessment should not only include reviewing the detailed assumptions and cost forecasts provided by the businesses, but also, whether the conceptual basis for including that cost is consistent with the detailed requirements of the Rules.

### 3.5.2. Base year - variation by volume

Ausgrid and Essential Energy<sup>41</sup> have, for a number of operating expenditure activities (e.g., system maintenance expenditure), adopted a methodology that sees them adjust the base year figure for historical volume variations. As an example, Ausgrid state that<sup>42</sup>:

*'We used this method to forecast system maintenance inspection opex (excluding vegetation management). This method is appropriate where there is an ability to accurately predict the forecast volume of tasks that varies from the base year volume. For example, the required number of planned inspection and routine maintenance tasks is driven by the number of items of equipment and the applicable maintenance cycle and standards. Maintenance cycles are determined on the basis of failure modes effects criticality analysis (FMECA), and expenditures are determined on the basis of historical costs'*

Ausgrid state that the average cost per task is comprised of two elements. These are<sup>43</sup>:

- *The 'base' average unit cost - this is the actual average cost per task incurred during the financial year 2012/13. It is derived by dividing the total actual opex incurred by the number of completed tasks.*
- *Cost escalation - cost escalation is applied to the base average unit cost to calculate the forecast average unit cost for each year of the 2014-19 period. The average cost per task is then applied to the forecast volume of tasks to derive the total system maintenance inspection forecast opex for the 2014-19 period.*

Our primary concern relates to the fact that:

- Ausgrid and Essential Energy derive an '*actual average cost per task*' in the base year and then multiply that average cost by a forecast of the volume of inspections. On face value, this approach will not reflect the actual increased cost of providing increased inspections over the forthcoming regulatory control period, as it uses the average cost, and not the marginal cost of providing these services. If such an approach were to be utilised, the appropriate forecasting methodology would be to derive an average *marginal* cost in the base year, and add/subtract costs onto/from the base year amounts, based on that marginal cost \* the difference in volumes between those forecast and what actually occurred in the base year<sup>44</sup>. The magnitude of the impact of this change in methodology will depend on the extent to which businesses' operating expenditure in these relevant cost categories include fixed costs. The more fixed costs there are in the base year costs, the more the methodology proposed by the businesses will lead to forecasts that deviate from those that prudent and efficient service providers would incur,
- Following on from the above, we note that there appears to be a significant difference between Ausgrid's<sup>45</sup> revealed marginal cost's (for conducting additional inspections in 2013/14, relative to 2012/13), and the average cost that they are using in their forecasting methodology. Taking their three largest expenditure categories as examples:

41 See Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 70

42 Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 54

43 Ibid

44 An alternative approach, which would approximate the same outcome, would be to adopt a scale efficiency factor, which we note, the AER has adopted in other regulatory decisions (e.g., 2011 Victorian Electricity Distribution Pricing Review)

45 Due to time constraints, we have not assessed Essential Energy's 'revealed' marginal costs



- Ausgrid has forecast the average cost per inspection for Distribution Substations as \$499 per inspection in FY2014 dollars<sup>46</sup>, whereas, the marginal cost (being the change in volume divided by the change in total cost between 2012/13 and 2013/14) that they are revealing in 2013/14 is \$40 per inspection<sup>47</sup>;
- Ausgrid has forecast the average cost per inspection for Distribution Mains as \$103 per inspection in FY2014 dollars<sup>48</sup>, whereas, the marginal cost (being the change in volume divided by the change in total cost between 2012/13 and 2013/14) that they are revealing in 2013/14 is \$32 per inspection<sup>49</sup>; and
- Ausgrid has forecast the average cost per inspection for Zone Substations as \$314 per inspection in FY2014 dollars<sup>50</sup>, whereas the marginal cost (being the change in volume divided by the change in total cost between 2012/13 and 2013/14) that they are revealing in 2013/14 is \$32 per inspection<sup>51</sup>.

We note that the revealed marginal costs fluctuate markedly over the current period, and that there may be a reasonable justification as to why the 2013/14 revealed marginal costs may not be fully representative of future marginal costs of undertaking additional inspections (net of the impact of cost escalation). That said, to our mind, the magnitude of the difference, in combination with the broader conceptual question-mark over the forecasting methodology, raises concerns in relation to the use of this methodology.

Finally, we also note that the forecasting methodology:

- Does not have regard for whether there is a change in the mix (types) of inspections undertaken in the forthcoming regulatory control period, relative to the base year. That said, Ausgrid, for one, provide some evidence to suggest that this is unlikely to be material.

In summary, unless Ausgrid and Essential Energy's base year costs in the relevant cost categories are *entirely incremental, over the range of inspections volumes being modelled* (which prima facie, they do not appear to be), then the proposed approach, as we read it, will not lead to operating expenditure forecasts that are consistent with the operating expenditure criteria outlined in Section 6.5.6 (c) of the Rules, in particular, they will not reflect the efficient costs of achieving the operating expenditure objectives, nor would they reflect the costs that a prudent operator would require to achieve the operating expenditure objectives.

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46 Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 60

47 Based on information on pages 18 and 19 of Ausgrid's *System Maintenance Operating Expenditure Plan for the 2014-19 period*

48 Ibid, page 58

49 Based on information on pages 18 and 19 of Ausgrid's *System Maintenance Operating Expenditure Plan for the 2014-19 period*

50 Ibid, page 55

51 Based on information on pages 18 and 19 of Ausgrid's *System Maintenance Operating Expenditure Plan for the 2014-19 period*

### 3.5.3. Base year - historical average

Ausgrid<sup>52</sup> and Essential Energy have, for a number of operating expenditure activities (e.g., nature induced breakdown costs), adopted a methodology that sees them adjust the base year figure for historical volume variations. As an example, Essential Energy state that<sup>53</sup>:

*We used this method to forecast nature induced breakdown costs. This method is appropriate where there is significant variation in year-to-year expenditure and the base year is not representative of the likely future. This involves taking a historical average of the costs captured during the first four years of the 2009-14 regulatory control period and substituting the average for the base year actual operating expenditure.*

Based on a literal interpretation of this comment, we have concerns at a conceptual level regarding whether this in fact leads to the true revealed (efficient) costs being reflected in the forecasts. In particular, taking an 'historical average of the costs captured during the first four years of the 2009-14 regulatory control period and substituting the average for the base year actual operating expenditure' in effect, means that multiple data points are being averaged - with each data point being a function of both actual unit rates in that year and volumes in that year.

Whilst the intention of the approach appears to be to normalise for volume variation, the approach, if adopted as stated, would also average the unit costs. The issue that this creates is that the unit rates in an individual year, do not reflect the efficiencies gained in future years. For example, the unit rates for years 1-3 of the current regulatory control period, **do not** reflect the efficiencies made in year 4 (which is the base year). More specifically, this approach means that:

- 100% of any efficiency made in year 1 (that carries through the remainder of the regulatory control period) flows through to the forecast unit costs;
- 75% of any efficiency made in year 2 (that carries through the remainder of the regulatory control period) flows through to the forecast unit costs;
- 50% of any efficiency made in year 3 (that carries through the remainder of the regulatory control period) flows through to the forecast unit costs; and
- 25% of any efficiency made in year 4 (that carries through the remainder of the regulatory control period) flows through to the forecast unit costs.

This occurs because of the use of the average of total costs over the period. An even simpler way of conceptualising this issue is to assume that in fact, volumes remained exactly the same over the current regulatory control period, and unit costs remained the same in years 1-3 of the regulatory control period, but reduced by 10% in year 4 (the base year). The averaging process proposed by the businesses would mean that only a 2.5% efficiency gain - not the 10% efficiency gain achieved in 2012/13 - would be reflected in the forecast costs.

An alternative methodology that would have better aligned with the 'revealed cost' approach, but normalised for volume variation, would have been to derive the average *volume* over the period, not the average cost over the period, and then multiply the difference between that average volume and actual volume in 2012/13 by the *marginal cost* in 2012/13 base year (with this adjusted for any cost escalation factors that are consistent with the efficient delivery of that service). That said, we believe that the AER should simply assume that actual opex in the base year would lead to the best estimate of opex possible in the circumstances, and that this cost be reflected in the calculation of the EBSS.

<sup>52</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 54

<sup>53</sup> The same comment is contained in the Ausgrid Regulatory Proposal on page 54

In summary, unless Ausgrid and Essential Energy's unit costs reflect all of the efficiencies they have revealed over the current regulatory control period, then we do not believe that the businesses proposed approach will lead to operating expenditure forecasts that are consistent with the operating expenditure criteria outlined in Section 6.5.6 (c) of the Rules. In particular, they will not reflect the efficient costs of achieving the operating expenditure objectives, nor are the costs that a prudent operator would require to achieve the operating expenditure objectives.

A secondary issue that we have with Ausgrid and Essential Energy's proposed approach is that it may break the link between the EBSS and forecast operating expenditure that is driven off the base year, if the EBSS is not based on the value used to forecast underlying operating expenditure. In particular, the alignment between the EBSS and the base year expenditure levels means that the gains/losses from abnormal weather events in a particular period (which would not have been 'management' driven) would be offset in the long-term when volumes returned to normal. For example, any abnormal gains (i.e., favourable weather conditions leading to lower costs) in the current regulatory control period will lead to a higher EBSS allowance in the forthcoming regulatory control period, but lower forecast operating expenditure; conversely, any abnormal losses (i.e., unfavourable weather conditions leading to higher costs) in the current regulatory control period will lead to a lower EBSS allowance for the forthcoming regulatory control period, but higher forecast operating expenditure forecasts. We would argue that this means that such an approach is inconsistent with Clause 6.5.6 (e)(8), namely '*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.*

Finally, we note that at least one of the AER's recent decisions has aligned with what we have suggested above. In particular, in its most recent Gas Access Arrangement submission, SP AusNet proposed not to use its 2011 maintenance expenditure (which was its base year) for the purpose of forecasting its maintenance costs in its 2013-17 gas access arrangement period. Instead, it proposed to use an average of maintenance expenditure incurred in 2008-10. According to the AER, this was to account for the fact that it spent less on maintenance compared to budget - which it attributed to higher than average rainfall during the first quarter of 2011, continued seasonal rainfall thereafter and a contract structure that was favourable to SP AusNet for water related maintenance activities<sup>54</sup>. In its Draft Decision, the AER states that<sup>55</sup>:

*The AER's draft decision is not to use an average of maintenance expenditure in 2008-10 for its base year estimate. It considers that this methodology would not result in a total forecast of opex that has been arrived at on a reasonable basis or is the best estimate possible in the circumstances.*

*In any one year there are likely to be some costs that are higher than business-as-usual and some costs that are lower than business-as-usual. As there are many factors that influence actual opex in any one year in both directions, the AER considers a forecast of total opex is more likely to include estimation errors if a forecast is not reflective of all opex incurred a calendar year. As discussed above, the AER considers that actual opex in 2011 would lead to the best estimate of opex possible in the circumstances.*

<sup>54</sup> AER, *Access Arrangement draft decision SPI Networks (Gas) Pty Ltd 2013-17, Part 2 Attachments*, page 222

<sup>55</sup> *Ibid*

*The AER also notes that SP AusNet is subject to an efficiency carryover mechanism under which SP AusNet retains the benefit of its reduced maintenance expenditure in the 2008-12 access arrangement period. As a result of this underspend, SP AusNet has accrued a carry over which will increase its allowed revenue for the next five years. If SP AusNet is permitted to apply a normalisation of base year maintenance expenditure then SP AusNet will retain the benefits of underspending in the 2008-12 access arrangement period but its maintenance expenditure in the 2013-17 access arrangement period would not be adjusted to reflect lower expenditure. An inconsistent approach between the opex used in the ECM<sup>56</sup> and the opex used in setting base opex would lead to over-compensation for reduced maintenance expenditure in the base year.*

### 3.5.4. Enterprise Bargaining Agreement and labour cost escalators

#### Enterprise Bargaining Agreement

Ausgrid<sup>57</sup> and Essential Energy's<sup>58</sup> forecast labour cost escalation rates reflect their current enterprise bargaining agreements (EBA), after which they use forecasts derived by Independent Economics.

It is noted that the AER has previously not allowed EBA rates to be utilised to forecast expenditure in future regulatory control periods. For example, in the 2011 Victorian Draft Decision, it stated<sup>59</sup>:

*The AER considers that compensating a DNSP for actual EBA wage increases in its expenditure forecasts largely eliminates the incentive for a regulated DNSP to actively pursue efficient and competitive wage outcomes during EBA negotiations. The AER acknowledges that salaries, and annual salary increases, are fundamental bargaining tools in EBA negotiations. However, it also considers that efficient and prudent DNSPs would actively seek to negotiate favourable terms and conditions by leveraging other, non-financial outcomes, even in circumstances of perceived or apparent skilled labour shortages.*

*Compensating for actual EBA wage increases does not incentivise the DNSPs to develop innovative bargaining strategies to attract and retain labour resources, as many businesses in competitive markets would do in response to normal market pressures. Nor does the full compensation of historical EBA wage increases recognise that skilled labour shortages observed in recent years will invariably recede due to adjusting economic factors, such as resource mobility and other supply side factors, in the medium to long term.*

*The AER will, however, observe the actual EBA wage rate increases incurred by the Victorian DNSPs up until the beginning of the forthcoming regulatory control period.*

This was confirmed as part of the Final Decision.<sup>60</sup>

<sup>56</sup> Efficiency Carryover Mechanism

<sup>57</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 55

<sup>58</sup> Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 75

<sup>59</sup> AER, *Draft decision Victorian electricity distribution network service providers Distribution determination 2011-2015, Appendices*, June 2010, page 136

<sup>60</sup> AER, *Final decision - appendices, Victorian electricity distribution network service providers - Distribution determination 2011-2015, October 2010*, page 252 - 253

For completeness, we note that Ausgrid utilises its EBA up until December, 2014, or 6 months into the forthcoming regulatory control period<sup>61</sup>, whilst Essential Energy's is used up until June 2015<sup>62</sup>.

We tend to agree with the AER's aforementioned interpretation of the Rules, therefore, we do not believe that the businesses proposed approach of using its EBA rates in the forthcoming regulatory control period will lead to operating expenditure forecasts that are consistent with the operating expenditure criteria outlined in Section 6.5.6 (c) of the Rules. In particular, they will not reflect the efficient costs of achieving the operating expenditure objectives, nor are they costs that a prudent operator would require to achieve the operating expenditure objectives.

### General labour cost escalators

All of the businesses have used forecast labour escalators provided by 'Independent Economics'. Ausgrid and Essential Energy have applied these escalators once their EBA's have ceased, whereas it appears that Endeavour Energy have applied these for the entire regulatory control period<sup>63</sup>.

These are based on the Wage Price Index of labour cost growth, which we consider reasonable, and which we note is consistent with recent regulatory practice. We are not in a position to provide a detailed critique of the magnitude of these forecasts per se, although we would encourage the AER to investigate in more detail, how the material increase in nominal (and real) wage growth towards the end of the forthcoming regulatory control period can be reconciled with:

- Implied reductions in the demand for labour by the NSW electricity networks in NSW as a result of:
  - Their reduced capital expenditure programs, relative the current regulatory control period (for example, Essential Energy states that<sup>64</sup>: "*we have commenced a program to transition our labour workforce over the 2014-19 regulatory control period to a sustainable level. We have begun a 'mix and match' voluntary redundancy program which has been approved by the Australian Taxation Office. Under this program we seek expressions of interest from our eligible employees who may be interested in voluntarily leaving Essential Energy*"), and
  - A move to more sustainable labour levels as a result of the creation of Networks NSW (for example, Essential Energy states that while<sup>65</sup>: "*Essential Energy would have preferred to redeploy surplus labour requirements to other parts of the business, there is limited scope to do so because the rationalisation of functions across the three DNSPs as part of the NSW Government's industry reform will result in additional surplus requirements rather than vacancies*"), and

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61 Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 56

62 Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 75

63 Endeavour Energy, *Regulatory Proposal to The Australian Energy Regulator*, 1 July 2015 - 30 June 2019, page 82

64 Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 78

65 Ibid

- Business investment being forecast to weigh down growth over the evaluation period, and in particular, the fact that this is expected to be “*dragged down by the falloff in mining investment from very high levels*”<sup>66</sup>. More specifically, it is not clear to us why the wages in those occupations that have been supported by strong demand in the rapidly expanding mining sector would be ‘*expected to continue as the mining industry transitions from the investment phase*’<sup>67</sup>.

We also note that:

- Different forecasters will inevitably provide different results (see example below), and
- Therefore, it is important for the AER to obtain an alternate forecast to assess the robustness of the forecasts presented by the business.

By way of example, the following two figures highlight the escalators produced by Independent Economics (for the NSW DBs), as well as the escalators produced by BIS Shrapnel (for Jemena’s recent NSW Gas Access Arrangement Submission). A simple comparison highlights the fairly material difference in some years, which is interesting given that the BIS forecasts were produced at around the same time as the Independent Economics forecasts.

Figure 1: Independent Economics labour cost escalators for the NSW DBs

Table B. Growth in nominal wages in the Utilities industry (per cent)

	Utilities Industry - WPI wages				Utilities Industry - AWE wages			
	Australia	NSW	Tasmania	ACT	Australia	NSW	Tasmania	ACT
2009-10	4.3	3.8	4.9	4.3	8.9	7.5	10.7	10.1
2010-11	4.1	3.5	3.8	4.0	10.7	9.5	12.8	13.3
2011-12	3.5	3.2	3.5	3.4	2.6	1.9	4.2	4.8
2012-13	4.2	3.7	4.2	4.8	3.9	4.2	4.3	5.3
2013-14	3.4	3.1	3.2	3.3	2.5	1.9	0.8	1.6
2014-15	3.6	3.6	3.4	3.7	2.2	1.7	1.9	3.0
2015-16	4.0	3.9	3.9	4.0	4.2	3.7	4.0	5.0
2016-17	4.6	4.6	4.5	4.6	5.9	5.5	5.7	6.6
2017-18	4.9	4.9	4.8	4.9	6.1	5.8	5.9	6.6
2018-19	4.8	4.7	4.6	4.7	5.3	5.2	5.2	5.7

Source: ABS; Independent Economics

Source: Independent economics, *Labour escalation for NSW DNSPs*, May 2014, page vi

66 Independent economics, *Labour escalation for NSW DNSPs*, May 2014, page 14

67 Ibid, page 26

Figure 2: BIS Shrapnel labour cost escalators for JGN

**Summary – Labour Cost Escalation Forecasts**

(per cent change, year average, year ended June)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	5 yr Avg (g)	7 yr Avg
<b>NOMINAL PRICE CHANGES</b>	Actuals			Forecasts		Next Regulatory Period						
1. Gas Network-Related Labour												
EGWWS AWOTE - New South Wales (p,b)	4.4	1.5	5.1	4.0	3.9	4.0	5.2	5.6	5.5	5.1	5.1	4.8
EGWWS WPI - New South Wales (a)	3.5	3.2	3.7	3.6	3.4	3.7	4.2	4.5	4.7	4.8	4.4	4.1
EGWWS AWOTE - Australia (c)	9.1	2.5	6.1	4.3	4.2	4.4	4.9	5.4	5.6	5.1	5.1	4.8
EGWWS WPI - Australia (c)	4.2	3.5	4.2	3.7	3.6	3.8	4.1	4.4	4.4	4.7	4.3	4.1
2. Contractor Labour Cost Escalation												
Construction AWOTE - New South Wales (d,b)	-4.6	4.3	4.5	3.5	3.6	4.0	4.8	4.7	4.5	4.7	4.5	4.2
Construction WPI - New South Wales (d)	4.1	3.2	3.3	3.0	3.3	3.7	4.1	4.0	3.7	3.9	3.9	3.7
Construction AWOTE - Australia (c)	5.0	3.5	4.3	3.3	3.4	3.8	4.6	4.6	4.8	5.1	4.6	4.2
Construction WPI - Australia (c)	4.0	4.1	3.3	2.9	3.0	3.5	3.9	3.8	3.9	4.1	3.9	3.6
3. Australian Wages												
All Industries - AWOTE (e)	4.2	4.3	4.6	3.3	3.8	4.3	5.0	4.9	4.3	4.8	4.7	4.3
All Industries - WPI (e)	3.8	3.6	3.3	2.7	3.1	3.6	4.0	3.8	3.8	4.0	3.8	3.6
Consumer Price Index (headline)(f)	3.1	2.3	2.3	2.8	2.8	2.5	2.5	2.5	2.5	2.5	2.5	2.6

Source: BIS Shrapnel, *Real Labour and Material Cost Escalation Forecasts to 2019/20 - Australia and New South Wales*, FINAL Report, April 2014, page ii

To summarise, we are not in a position to comment upon the overall magnitude of the labour costs forecasts provided by Independent Economics, and utilised by the NSW businesses. However, we would expect the AER to undertake an independent assessment of these forecasts as part of their broader review process, and to pay particular regard to how the material increase in nominal (and real) wage growth towards the end of the forthcoming regulatory control period reconciles with other factors reflected in the businesses regulatory proposals that will affect the supply and demand for labour

### 3.5.5. Driver for inspection - Ausgrid and Endeavour Energy

Ausgrid states that<sup>68</sup>:

*The impact of system capex on inspection maintenance costs - the cost of routine inspection is dependent on the volume of inspection. The volume of inspection tasks for the 2014-19 period is determined with reference to the number of assets which in turn are impacted by the forecast replacement and capacity investment program for the next period*

Endeavour Energy states that<sup>69</sup>:

*We will forecast opex at the category level for opex categories that are recurring activities based on total network size.*

Endeavour Energy also state that<sup>70</sup>:

*For the activity level forecasts, we will firstly develop forecast unit costs for the identified network maintenance activities using a trend based on 1 to 3 years of historical costs (inclusive of saving initiatives) which will be applied to the future Network Maintenance plan volumes for the 2014/15-2018/19 regulatory period to determine the Network maintenance operating expenditure forecasts.*

In summary, both Endeavour and Ausgrid appear to have escalated their forecast maintenance costs by volume of inspection tasks, which, broadly, is a function of the number of assets/network size.

In comparison, Essential Energy has adopted a different approach. They state that<sup>71</sup>:

*Most of the forecast operating expenditure is associated with the existing asset base. However, growth related capital expenditure increases the size of the network and the number of assets to be maintained, operated and managed. Accordingly, there is a need to establish a relationship between growth related capital expenditure and real increases in operating and maintenance expenditure. Essential Energy has used the approved method from the AER's final determination for the 2009-14 regulatory control period in applying this growth factor to operating expenditure. The calculation of this growth factor can be found at Attachment 6.4.*

Upon review, Essential Energy's approach appears broadly to be based on the proportionate increase in the value of their asset base (in replacement cost terms) resulting from net growth related capital expenditure, with an additional allowance for the fact that:

*'when assets at the end of their service lives are either refurbished or renewed it is reasonable to expect a reduction in OPEX expenditures associated with these assets within the current regulatory period'<sup>72</sup>.*

<sup>68</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 55

<sup>69</sup> Endeavour Energy, *Expenditure Forecasting Methodology*, page 9

<sup>70</sup> Ibid, page 3

<sup>71</sup> Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 75

<sup>72</sup> Note contained in Attachment 6.4\_Asset Growth Escalator- 2014.xls



Overall, the methodologies appear to lead to quite significant differences in future cost escalation related to output growth. For example, Essential Energy is ascribing a \$31M<sup>73</sup> increase in total costs to 'Asset growth escalation' over the forthcoming regulatory control period, whereas Endeavour Energy is ascribing \$157M<sup>74</sup> to output growth<sup>75</sup> over the forthcoming regulatory control period.

To give some context to these figures, in its Final Decision for the Victorian distribution business, the AER provided the businesses with the following allowances for scale escalation<sup>76</sup>:

Table 4: Scale escalation provided to the Victorian Distribution businesses

Distribution Business	Allowance over the 2011-2015 regulatory period (\$million 2010)
Citipower	\$3.9
Powercor	\$17.7
Jemena	\$3.8
SP AusNet	\$10.8
United Energy	\$4.8

Even after allowing for the fact that the above costs are in \$2010, and the NSW businesses forecasts are in \$2013-14, this difference is so stark as to render either the forecasts of at least one of the NSW business demonstrably inefficient, or the AER's recent decision in Victoria grossly inadequate, as the magnitude of this difference is simply not explainable by differences in replacement levels, customer growth rates or any other cost driver.

Aside from the above comparison, we note that whilst conceptually, we agree that there is likely to be some correlation between the number of assets in service and maintenance costs, neither Ausgrid nor Endeavour Energy have:

- Presented any empirical evidence to support this relationship, and
- Incorporated any allowance for scale and scope benefits<sup>77</sup> associated with undertaking more inspections across their regions (which, we note, is something the AER has previously incorporated into 'work volume escalators').

73 Based on information contained in Table 6-4 on page 73 of Essential Energy's *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014

74 Endeavour Energy, *Regulatory Proposal to The Australian Energy Regulator*, 1 July 2015 - 30 June 2019, page 84

75 NOTE: Ausgrid do not isolate the impact of their 'output growth' assumption on their total operating expenditure forecast.

76 AER, *Final decision - appendices Victorian electricity distribution network service providers Distribution determination 2011-2015*, October 2010, page 230

77 This also links back our discussion in an earlier section regarding the businesses use of the 'average cost' instead of the 'marginal cost' as the unit rate that they are applying to their forecast volumes of inspections.

Further, we note that in theory, inspections are likely to be a function of the underlying *probability* and *consequence* of failure of the asset being inspected, with inspections increasing as the probability and/or consequence of failure increases, and conversely, inspections reducing as the probability and/or consequence decreases.

We note that Ausgrid does discuss this in their System Maintenance Operating Expenditure Plan<sup>78</sup>:

*As noted previously, the cost of maintaining assets generally increases as the asset approaches the end of its life, and this is a key input into the decision to renew an asset. Consequently, where there is accelerated investment in replacement, maintenance costs would be expected to decline. Conversely, where replacement levels are reduced, maintenance costs would be expected to rise. Investment in new capacity can also have an effect, as it is often the case that the most economic means of servicing additional demand involves the replacement of older infrastructure with newer, larger capacity equipment.*

*This effect was considered as a particular case of the base year method with variation in volume. In this case, the method involved examining the expected change in age profile of an asset class from the base year to the end of the next period, based on planned replacement volumes. By multiplying this change by the profile of expected maintenance costs based on age, it is possible to estimate a shift in maintenance costs due to the effect of the capital program. The method is limited due to the need for reasonable quality data, however, a sensitivity analysis was undertaken to determine if the impact was likely to be material. The proposed capacity investment program is small and unlikely to have any material impact, and was disregarded.*

*Ausgrid has determined that it is unlikely that there would be any material change in maintenance costs over the 2014-19 period based on the current proposed levels of replacement and sensitivity analysis that was undertaken.*

*However, if there was a material shift in the current proposed levels of replacement, it may be necessary to further develop the approach to correctly forecast the required maintenance costs and the need for reactive replacements.*

We take on face-value Ausgrid analysis on this issue, although it is unclear to us whether Endeavour Energy has undertaken a similar sensitivity analysis.

In summary, we would recommend that the AER give detailed consideration to the extent to which the methodology proposed by, in particular, Ausgrid and Endeavour Energy, complies with the Rules, particularly as there does not appear to be any empirical evidence presented to support the strength of the relationship; the significant difference in the forecast increase in expenditure by Essential Energy relative to Endeavour Energy (as quite likely, Ausgrid); and the absence of any consideration of scale efficiency factors. Finally, we would implore the AER to give detailed consideration as to why the forecasts provided by, in particular Endeavour Energy, are so materially different to the allowances provided to other regulated distribution businesses in Australia.

### 3.5.6. Actuarial adjustment to base year

Each of the businesses has proposed to undertake an actuarial adjustment to their base year. Essential Energy provides the following explanation for this adjustment<sup>79</sup>:

<sup>78</sup> Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 36-37

<sup>79</sup> Essential Energy, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 31 May 2014, page 71-72

*Our base year operating expenditure also contains year-end adjustments to reflect actuarial gains and losses in the assessments of our employee entitlement obligations. Actuarial gains and losses are changes in the present value of these obligations. These gains and losses result from adjustments made to reflect the differences between the previous actuarial assumptions and what had actually occurred as well as the effect of changes in actuarial assumptions. These adjustments need to be made as actuarial assumptions and future discount rates are very difficult to reliably predict over an extended period.*

*These adjustments are included in our actual operating expenditure for 2012-13 as required by Accounting Standards. However, the adjustments have been excluded from the base operating expenditure to ensure that the base operating expenditure amount, upon which cost escalation and change factors are applied, reflects the underlying ongoing operating expenditure needed to undertake the required activities to provide standard control services. This approach is consistent with that used to forecast our 2009-14 regulatory control period operating expenditure allowance approved by the AER.*

*We note that in recent decisions, the AER had reversed 'movement in provisions' from the base amount to reflect the cash payout rather than the amount accrued. The AER's approach effectively represents 'cash accounting' instead of 'accrual accounting'. Under the AER's approach, the forecast operating expenditure would reflect the estimated cash to be paid in the next five years in relation to liability provisions. Under the accrual approach we have adopted, the forecast operating expenditure represents the amount that accrues (e.g. long service leave, annual leave) based on actual year-to-date results.*

*We have not adopted the AER's approach of cash accounting because it has a real potential to result in significant variations in charges to customers as well as imposing further costs on Essential Energy which we must recover from customers. This is fundamentally against the NEO of ensuring the long-term interest of customers with respect to charges*

In its most simplest form, this issue comes down to whether the Rules (and the NEO) give guidance as to whether this expenditure should reflect the estimated cash to be paid out in the next five years in relation to liability provisions, or whether the forecast operating expenditure represents the amount that accrues (e.g. long service leave, annual leave) based on actual year-to-date results.

The Rules are quite unequivocal that the operating expenditure forecasts must be for the *relevant regulatory control period*. For example, the operating expenditure objectives outlined in Section 6.5.6 state:

*(a) A building block proposal must include the **total forecast operating expenditure** for the **relevant regulatory control period** which the Distribution Network Service Provider considers is required in order to achieve each of the following..*

They are less equivocal, however, about whether this should be based on a cash or accrual basis. The AER, in its 2011 Victorian EDPR decision, states that a reason why these are removed is because they '*may be used to represent the reported accounts of the DNSPs differently from their underlying economic circumstances*<sup>80</sup>.

80

AER, *Final decision Victorian electricity distribution network service providers Distribution determination 2011-2015*, October 2010, page 326

In summary, our view would be that the appropriate methodology will be the one that best estimates the 'expected' costs to be incurred (and therefore, which needs to be funded) over the forthcoming regulatory control period. The following comment by Essential Energy may be instructive in assessing this: '*under the AER's approach, the forecast operating expenditure would reflect the estimated cash to be paid in the next five years in relation to liability provisions*'. If this is the case, that is, the AER's approach better reflects the operating expenditure that a prudent and efficient business will incur over the next 5 years in relation to liability provisions, then it would appear to indicate that the AER's current methodology is likely to better reflect the cash costs to the distribution businesses over the regulatory control period.

### 3.6. Endeavour Energy issues

#### 3.6.1. Vegetation management

Based on the information provided by Endeavour Energy in their Regulatory Proposal, it appears that:

- Endeavour Energy spent \$136.5M less than their vegetation management allowance in the current regulatory period<sup>81</sup>, *yet*
- Endeavour Energy are forecasting to increase their vegetation management spend (over and above their base year levels) in the forthcoming regulatory control period by \$130.6M<sup>82</sup>, and
- This increase contributes to an around 60% rise in vegetation management costs, relative to those revealed in the current regulatory control period.

Endeavour Energy's supporting argument is best reflected in the following quote<sup>83</sup>:

*Vegetation management represents a substantive and critical activity to Endeavour Energy. Endeavour Energy has mandated standards that set out the minimum clearances required for the safe operation of the distribution network. To ensure that we deliver value for money services we externally source a significant majority of this function.*

*To implement appropriate contract management, incentivise our providers and target best performance our contracts are contingent on achieving full compliance with our standards.*

*For the 2009-14 period we were able to secure improved overall vegetation costs, however we were required to exercise aspects of our contracts relating to insufficient conformance with our mandated standards. The impact of both of these matters has resulted in lower than expected vegetation management costs across the current regulatory control period.*

*In the 2014-19 period we are targeting further improvements to conformance with our standards. In the recent market tender process we have observed that the market has sought to price in the standard expected of them, and therefore we are forecasting increased costs for this activity. We consider vegetation management contributes to the achievement of the expenditure objectives and criteria, in particular managing bushfire, reliability and safety risk.*

Based on the above, our primary observations are that:

81 Endeavour Energy, *Regulatory Proposal to The Australian Energy Regulator, 1 July 2015 - 30 June 2019*, page 74

82 Ibid, page 84

83 Ibid, page 78

- Endeavour Energy does not refer to a *change in the standard required of it* (and therefore, its contractors), rather they state that the costs relate to '*further improvements to conformance with our standards*'. Therefore, prima facie, it appears that Endeavour Energy accepted non-conformance with their own standards during the current regulatory control period, with the trade-off being lower costs (and a higher EBSS allowance). Given Endeavour Energy makes no mention of there being any regulatory or legal ramifications from this non-conformance, one can only assume that the delivered level of service in the current regulatory control period was in fact consistent with its *minimum* externally imposed regulatory and legal obligations. Furthermore, given that there is no mention of these external obligations changing in the next regulatory control period, one can only assume that if Endeavour Energy continued to deliver these existing levels of service, they would still meet the *minimum* levels of service required over that regulatory control period, and
- It is noted that despite reducing its vegetation management costs over the current period, Endeavour Energy still improved its SAIDI (although we note that a number of issues may have contributed to this, including the large capital program that Endeavour Energy undertook over the period). We further note that as part of its STPIS proposal, Endeavour Energy has chosen to use its 5 year historical average as the benchmark against which SAIDI is measured for the purposes of calculating financial benefits/costs under that scheme<sup>84</sup>. This is *despite proposing to increase its vegetation management costs to further improve its conformance with its standards*.

In summary, our reading of Endeavour Energy's proposal is that they are seeking a higher cost allowance for vegetation management to increase conformance to their current internal standards, despite there being no change in their external regulatory obligation (and therefore, the minimum level of service that they must achieve in the next regulatory control period), and despite that fact that they accepted this lower conformance throughout the current regulatory control period. As an aside, we note that neither of the other NSW distribution businesses appear to have sought additional expenditure to meet any change in external regulatory obligation related to vegetation management, which is prima facie evidence to suggest that there has been no change in the externally imposed regulatory obligations affecting NSW distribution businesses. Further, Endeavour Energy is not proposing to adjust its SAIDI benchmarks for the purposes of their STPIS scheme, despite vegetation management being a key contributor to SAIDI (see figure below).

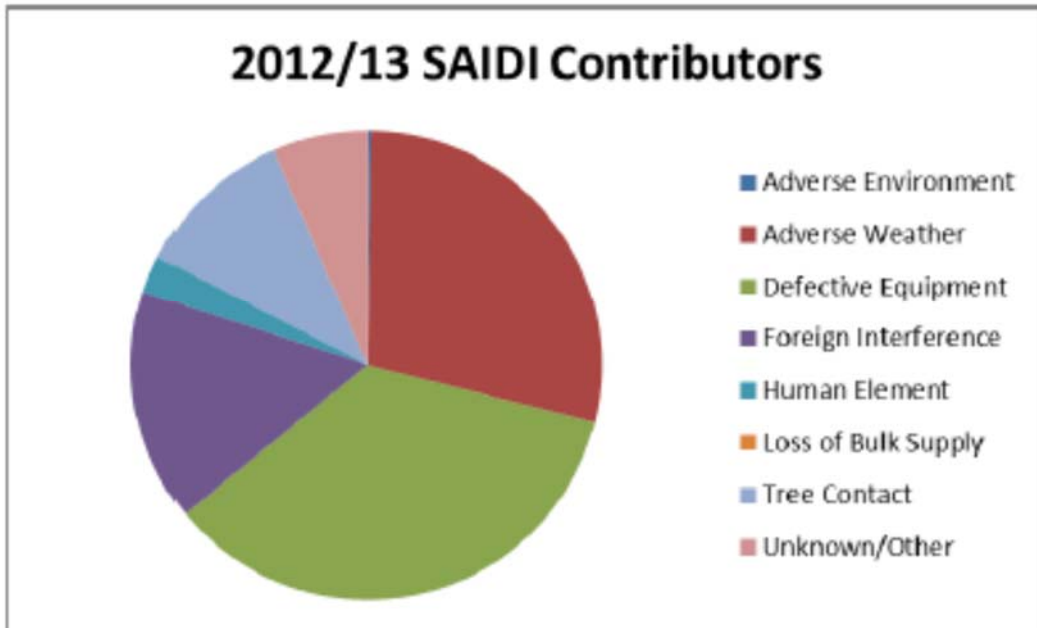
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Endeavour Energy, *STPIS Proposal 2014-2019 Regulatory Control Period*, page 4

Figure 3: Contributors to normalised SAIDI for Endeavour Energy

Figure 1.5: Contributors to Normalised SAIDI



Source: Endeavour Energy, *Network Management Plan*, December 2013 Review, page 13

Section 6.5.6(a)(2) of the Rules states that one of the operating expenditure objectives is to ‘comply with all applicable regulatory obligations or requirements associated with the provision of standard control services’. Based on the information provided by Endeavour Energy in its Regulatory Proposal, their base year expenditure is likely to reflect the efficient cost of complying with all of their relevant existing regulatory obligations, and moreover, there does not appear to have been a change in these regulatory obligations. Given this, we believe that the cost allowance that Endeavour Energy is proposing in order to ‘improve conformance’ with its existing internal standards<sup>85</sup> should be rejected, particularly given that it is also proposing to use the 5 year historical SAIDI average as part of the STPIS.

<sup>85</sup> To be clear, this relates to the cost allowance associated with conformance with standards. Other cost escalation factors should be analysed separately.

Further, we note that Endeavour Energy's business customers, and '*most residents were happy with the level of reliability they receive from Endeavour Energy and so were not particularly willing to pay more for a more reliable service - 75% of domestic customers and 92% of businesses felt this way*<sup>86</sup>. Prima facie, this indicates that any increase in the level of vegetation management expenditure to improve service outcomes would not be justified against the overarching National Electricity Objective (i.e., customer's do not appear to be willing to pay for the improvements in SAIDI<sup>87</sup> that are provided by increased vegetation management costs).

Finally, if the AER however chooses to provide Endeavour Energy with an operating expenditure allowance for '*further improvements to conformance with their standards*', then Endeavour Energy's STPIS benchmarks, in particular the benchmark SAIDI minutes off supply target, should be adjusted to reflect this additional expenditure.

### 3.6.2. Increase in emergency response expenditure

Endeavour Energy defines emergency response as<sup>88</sup>:

*Emergency response. This covers fault and emergency repairs and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. When notified of an interruption to customer supply, Endeavour Energy promptly dispatches field employees to deal with the fault.*

Endeavour Energy forecasts Emergency Response expenditure to rise from \$46.4M (\$13/14) in 2014/15 to \$55M (\$13/14) in 2018/19, or 4.35% per annum in real \$2013/14 terms, or 15.5% over the regulatory control period. This growth rate is substantially larger than any of Endeavour Energy's other network maintenance or operating cost categories.

There does not appear to be any specific information in either Endeavour Energy's Regulatory Proposal, or its Expenditure Forecasting Methodology document, describing the escalation rates or methodology that have been applied to this cost category, and moreover, how these differ to other cost categories.

Furthermore, it is not clear how the forecasts of expenditure in this cost category, reflect assumptions with regards to expenditure in other cost categories. For example, Endeavour Energy's proposed increase in vegetation management expenditure would, one would think, reduce its emergency response expenditure, given vegetation management is a key driver of USAIDI.

We would strongly encourage the AER to investigate this cost component in detail as part of its review process.

<sup>86</sup> Endeavour Energy, *Regulatory Proposal to The Australian Energy Regulator*, 1 July 2015 - 30 June 2019, page 19

<sup>87</sup> Notwithstanding this, we acknowledge that vegetation management will also reduce bushfire risk, which has a benefit to the broader customers and the broader NSW community. That said, this benefit is not mentioned as a driver, so it would appear that the 'increased conformance' is not driven by a detailed cost/benefit analysis, which we believe would be a minimum requirement in order to justify the increased vegetation management costs under the NEO (as opposed to the Rules).

<sup>88</sup> Endeavour Energy, *Regulatory Proposal to The Australian Energy Regulator*, 1 July 2015 - 30 June 2019, page 94

### 3.6.3. Regulatory re-set costs

Endeavour Energy states that<sup>89</sup>:

*Non-routine costs are not a function of the current base year costs; therefore the base step trend 'revealed cost' method would not be appropriate. Rather, other factors such market benchmarks (insurance premium costs), statutory obligations (statutory charges for properties holding) or the nature of the costs themselves (demand management, loss of synergy costs, payment from provisions) require the use of individual project forecasts.*

It goes on to state that<sup>90</sup>:

*Endeavour Energy incurs cost for preparing regulatory proposals. This cost is expected to be incurred in years 3 to 5 of the 2014-19 regulatory period. While costs are expected to increase in real terms, Endeavour Energy had proposed the same amount that it had incurred or expect to incur in the current period in relation to regulatory reset costs. This is a reduction in real terms as real cost escalation had been offset by productivity improvements and efficiency savings.*

Whilst this appears reasonable on face value, the specific mechanics of how Endeavour Energy has incorporated this into their forecasts is not clear from their Regulatory Proposal. In particular, if they have added the costs of undertaking their regulatory re-set into their forecast expenditure in years 3-5, *without* removing this cost from their base year expenditure, then this will effectively double-count the recovery of those costs. Whilst we logically assume that this is not the approach that has been adopted, it is not entirely clear from Endeavour Energy's description of the Regulatory Re-set costs. Moreover, statements elsewhere in their Regulatory Proposal indicate that their base year forecast has focused only on adjusting for one other expenditure item<sup>91</sup>:

*As evident in the table above, the base year total actual operating expenditure has been adjusted for one off expenditure to ensure the base amount reflects recurrent expenditure only. **Specifically, the impact of an actuarial adjustment for employee entitlements has been removed as this is an unpredictable, non-recurrent cost. The base year cost for each category is then further adjusted to account for any change factors and trends that alter costs from the current amount required to provide standard control factors [Emphasis added].***

We trust that the AER will ensure that Endeavour Energy has not double-counted the recovery of these costs. We also note that the same comment applies to all of the cost categories listed as "other operating expenditure forecasts" on page 90.

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89 Ibid, page 90

90 Ibid

91 Ibid, page 84



### 3.7. Ausgrid issues

#### 3.7.1. Private mains

Ausgrid has proposed to spend an additional \$17.3M over the forthcoming regulatory control period, relative to its base year expenditure, on inspecting private mains<sup>92</sup>. We note that this is made up of the following costs<sup>93</sup>:

- Stage 1: Data Capture and Validation - \$2.8M
- Stage 2: Customer Consultation and Awareness Plan - \$0.51M
- Stage 3: Develop Routine Maintenance Inspection Plan - \$12.17M
- Stage 4: Other Support Costs - \$1.76M

In Appendix 6.03, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, Ausgrid elaborates upon the underlying driver for this expenditure<sup>94</sup>:

*Whilst Ausgrid have robust policies and procedures in place for our own assets, our current inspection policies do not cater for the inspection of privately owned overhead mains or support structures. Our policies are confined to Ausgrid's assets and extend to the point of demarcation between our network and that of the customer, typically at the point of attachment, 'A' pole or other connection point. This is stated clearly in our Network Management Plan, and is also reported annually as part of the Network Performance Review.*

*Although **the demarcation point is clearly stated within the NSW Service and Installation Rules**, the majority of customers are not aware of this or their responsibilities*

*Ausgrid has reviewed its obligations under the Electricity Supply (Network Safety and Management) Regulation 2008 regarding the inspection, testing and maintenance of private mains and the extent of these obligations. Whilst the regulation does **not directly oblige Ausgrid to provide an inspection service**, legal advice is that the regulation does impose a clear obligation on Ausgrid to **ensure that such inspection, testing and maintenance occur**. Ausgrid has determined that it needs to improve its processes to ensure the inspection, testing and maintenance of private mains connected to our network is carried out on a regular basis. Currently, Ausgrid is at risk of breaching the regulatory and statutory obligations imposed under the Electricity Supply (Safety and Network Management) Regulation 2008, specifically clauses 10(2c) and 12(2e).....*

*Ausgrid staff are sometimes required to climb private poles to complete necessary work. As noted previously, **despite clear demarcation**, private owners of electrical infrastructure are not aware of their obligation to maintain, therefore it is likely that maintenance on those assets has not been undertaken for some time, if at all. This poses a significant safety risk to Ausgrid employees who are required to work either directly on, or in close proximity to privately owned assets. There is also a significant safety risk to the customer and owner of the private assets, particularly in bushfire prone areas as the condition of these assets is largely unknown.*

*Customers are responsible for keeping private overhead powerlines free of vegetation, and must ensure that only appropriate trees are planted in areas that are close to powerlines. **Customers are also responsible for the inspection, testing and maintenance of their powerlines and poles at regular intervals, the same way we do.** [Emphasis added]*

<sup>92</sup> Ausgrid, *Regulatory Proposal 1 July 2014 to 30 June 2019*, 30 May 2014, page 57

<sup>93</sup> Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 43

<sup>94</sup> Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 7-8

Three key points appear to be quite clear to us from the above statement:

- The assets in question **are not owned by Ausgrid**, rather they are owned by individual customers who are also *'responsible for the inspection, testing and maintenance of their powerlines and poles at regular intervals'*. Ausgrid itself notes that there is a *clear demarcation* between private assets and their assets,
- The assets in question exist almost exclusively to facilitate the provision of electricity to **individual customers**, or in some more isolated circumstances, very small groups of customers. Put another way, they do not appear to be part of the shared network (no matter what reasonable definition of shared network is chosen), and therefore, their continued operation and maintenance is not relied upon by most (if not all) customers, and
- The legal obligation (which we are not qualified to critique) appears to require Ausgrid to *'ensure that such inspection, testing and maintenance occur'* - it does not appear to indicate that Ausgrid *must undertake* that inspection, testing and maintenance.

In its Final Framework and Approach Paper, the AER provides the following description of Standard Control Services<sup>95</sup>:

*We classify as standard control services those distribution services that are central to electricity supply and therefore **relied on by most (if not all) customers**. Most distribution services are classified as standard control, reflecting the integrated nature of an electricity distribution system. We regulate these services, typically, by determining prices or an overall cap on the amount of revenue that may be earned for all standard control services. These standard control services form the core component of an electricity bill.*

*Standard control services include network services, most network augmentations and, in limited circumstances, network extensions. These services encompass construction, maintenance and repair of the network for existing and new customers **[emphasis added]***

They also describe Alternative Control Services as<sup>96</sup>:

*Alternative control services are **customer specific** or customer requested services. These services may also have **potential for provision on a competitive basis** rather than by a single distributor.*

*Alternatively, certain customers may require these services. For these services, we set service specific prices to enable the distributor to recover the full cost of each service from customers using that service. We will determine prices for individual alternative control services in a variety of ways, suitable to specific circumstances. For example, only a few customers purchase ancillary network services (like a request for special meter reading or to relocate a power pole). **It would be inappropriate for all customers to fund provision of these services**. We therefore classify ancillary network services as alternative control. Public lighting is also classified as alternative control because a defined group of customers purchase these services, for example, local councils **[emphasis added]***

<sup>95</sup> AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013, page 8

<sup>96</sup> Ibid

In our view, based on the information provided in Ausgrid's Regulatory Proposal and in its supporting documentation (in particular, its *System Maintenance Operating Expenditure Plan*), we believe that the provision of such a service may not technically qualify as a standard control service, as the provision of these services is not *central to electricity supply and therefore relied on by most (if not all) customers*. Rather, the service relates to the inspection of assets that are generally owned by individual customers, who also have a legal requirement to inspect and maintain those assets. Moreover, over \$12M (or 70%) of the proposed costs relate to developing a routine maintenance inspection plan, which is described in the System Maintenance Operating Expenditure Plan as follows<sup>97</sup>:

*The third stage of the program is the implementation of routine pole and line inspections for private poles and lines that aligns with the same inspection task package and inspection frequency as the Ausgrid pole and line inspection tasks. The proposed program also includes the pre bush fire line inspections for those private assets located in bush fire areas.*

We note, therefore, that this seems to extend way beyond any need to simply 'ensure that such inspection, testing and maintenance occur', and even if it did, given that a large proportion of these inspection costs can be directly related back to individual customers, and their individual 'need' for inspection services, it would appear that Ausgrid could quite easily derive a fee-for-service for the provision of such a service - analogous to an Alternative Control Service<sup>98</sup>.

In summary, based on the information provided by Ausgrid as part of their Regulatory Proposal, we are of the view that expenditure on Private Mains is inconsistent with the operating expenditure objectives outlined in Clause 6.5.6 (a), which is premised on expenditure being for standard control services over the period.

### 3.7.2. Asbestos Containing Materials

Ausgrid states that<sup>99</sup>:

*The use of asbestos was commonplace as a building material until the late 1980s. In the electricity industry, it had a variety of uses, such as insulation for electrical wiring, known as cable bandages, in fire doors as well as in underground pit covers, electrical backing boards, cement sheeting and tiles.*

*Ausgrid manages the risks posed by asbestos exposure in its workplace via an Asbestos Safety Management Plan and its documented safe work processes. This plan has historically included the ad-hoc survey and inspection of asbestos-containing materials completed by Ausgrid staff. The ad-hoc inspection and survey work was mainly limited to larger substations and has been completed historically by contracted expert service providers on a reactive basis.*

*Current legislative requirements require that all inspections of asbestos-containing materials are conducted on a routine five yearly basis by competent persons. Ausgrid has therefore formulated an asbestos-containing materials asset audit strategy to undertake the comprehensive inspection of all assets by competent persons in accordance with these legislative requirements. Data obtained through the inspection of all assets will be recorded in a comprehensive asbestos register to detail the status of known asbestos in all forms throughout Ausgrid's electricity network and assets.*

<sup>97</sup> Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 44

<sup>98</sup> It treatment as an Alternative Control Service would also better reflect the fact that individual customers can go to 'the market' for the provision of these services,

<sup>99</sup> Ausgrid, *System Maintenance Operating Expenditure Plan for the 2014-19 period*, page 9-10

*The legislated requirements for the routine inspection of asbestos-containing materials by a competent person are in accordance with:*

- *NSW Work Health Safety Act 2011*
- *NSW Work Health Safety Regulation 2011*
- *NSW Code of Practice - Managing Asbestos in the Workplace*

Whilst we do not doubt that Ausgrid has an obligation to manage asbestos in the workplace, our query relates to whether there has been a *change in obligation* that would mean that the AER cannot assume that Ausgrid base year costs reflect the prudent and efficient costs of meeting its existing (and future) obligations. In saying this, we note that the management of asbestos was mentioned as a cost driver (although admittedly, in the context of their capex program) in Ausgrid (then EnergyAustralia's) 2009 Regulatory Proposal<sup>100</sup>:

*Separate strategic investment plans that focus on single investment drivers for the distribution network. The component focussed nature of these plans lends itself to a risk portfolio approach to optimise maintenance and replacement costs. These comprise..... Duty of Care Plan (for non-system asset elements such as **asbestos** removal, oil containment, fire stopping).....*

*The compliance focus for 2009-14 is on appropriate management of asbestos in the distribution network, oil containment in distribution centres, and asset security.*

The question then becomes in our mind - has there been a **change** in the requirements regarding how often asbestos containing material needs to be inspected, or the broader process around its management. It is not clear to us from the information provided, whether or not there has been a change in the requirements placed on Ausgrid. This concern is heightened by the reference to asbestos management in its 2009 Regulatory Proposal (indicating that it has previously had an obligation to manage this issue, and provided funds for the management of that issue). It is further heightened by the fact that neither of the other NSW electricity distribution businesses have mentioned a change in regulatory obligations regarding asbestos management as being a driver of their future operating expenditure.

If there has not been a change in the core requirements, then we believe that AER should presume that the costs to Ausgrid of meeting their existing regulatory obligations should be assumed to be reflected in Ausgrid's base year expenditure. This is consistent with a myriad of other recent decisions made by the AER.

### 3.8. Essential Energy issues

#### 3.8.1. Recovery of 'Stranded' Opex Costs resulting from reduced capex program

Essential Energy states that:

*...our forecast capital expenditure is approximately 26 per cent (\$2013/14) lower than that required for the 2009-14 regulatory control period.*

*The lower forecast capital expenditure program will not require as many resources as were needed to deliver the approved capital expenditure program in the 2009-14 regulatory control period. These resources were previously tasked with the delivery of the capital program and therefore **their costs were fully funded by the capital expenditure allowed by the AER for the 2009-14 regulatory control period. These stranded costs are a legitimate cost to be recovered as part of Essential Energy's operating costs.***

100 Energy Australia, *Regulatory Proposal*, June 2008, page 7 and page 67

Essential Energy follows on in a later section by saying:

*Essential Energy is facing a pool of excess resources and other stranded costs, despite the prudent action we undertook in outsourcing the construction of our major substation and subtransmission programs. While this prudent action has minimised the cost impacts of a reduced capital program on the forecast operating expenditure, the impact is still putting upward pressure on the cost base.*

*This is a critical issue that we have responded to in a measured way, **balancing the interests of our employees, customers and shareholders**. We need to undertake active measures to respond to the need of constraining the impact of charges on our customers and to ensure an efficient cost structure. To do nothing and maintain a level of resources that is in excess of requirements would not be a prudent option and would impose a burden on customers through charges higher than would otherwise be required.*

It further states that:

*The ramp-down in investment and the cessation of the TSA give rise to an inevitable need to evolve our business and to restructure our organisation so that **an efficient and sustainable level of resource is achieved** such that previously shared fixed costs are now for a network only business. Cost restructuring is a legitimate option and a well-accepted practice by businesses in response to changing needs and circumstances. In our case, it is a prudent course of action having regard to the interests of our customers and our long-term financial viability.*

*While it is a prudent option that ensures customers will not bear the financial burden of maintaining a workforce and other support costs (e.g. property / IT) in excess of requirements, Essential Energy nevertheless is **an employer with certain legislative obligations to its employees**, some of whom have been with us for a long period of time. We must meet these obligations.*

***These implementation costs** are legitimate expenditure that Essential Energy needs to recover as the efficient costs of providing standard control services. These initiatives represent a prudent option that will result in ongoing cost savings that will ultimately benefit our customers through lower charges. With the departure of these employees, Essential Energy will have a significant lower labour cost profile as well as reduced support costs such as information technology, property, finance and human resources.*

Firstly, it is unclear from Essential Energy's regulatory proposal what the overall magnitude of this issue is, or what is driving the overall cost. We assume, but we cannot be sure, that it includes:

- Labour costs that were capitalised in the current regulatory control period (based on the comment: '*their costs were fully funded by the capital expenditure allowed by the AER for the 2009-14 regulatory control period*'), but which will not be capitalised in the forthcoming regulatory control period, and therefore need to be recovered via (increased) operating expenditure allowances - with these costs slowly reducing over time as some of these staff leave Essential Energy, and/or
- Implementation costs associated with facilitating the reductions in staff contemplated by Essential Energy.

We also note that Essential Energy states that it has '*certain legislative obligations to its employees*', which we do not doubt, however it is unclear from reading their Regulatory Proposal, what these obligations are, and whether Essential Energy has simply met the minimum requirements of those obligations, or has gone 'over and above' those requirements.

Given the driver for this expenditure, it is worthwhile reviewing Essential Energy's actual, and forecast capital expenditure program. Both are captured in the following figure.

Figure 4: Essential Energy - Variation to forecast capital expenditure

Table 5-1 sets out our actual and forecast capital expenditure from 1 July 2004 to 30 June 2019<sup>99</sup>.

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Growth	80	107	212	227	236	280	253	279	254	212	189	159	140	135	129
Refurbishment	85	87	115	123	111	170	233	226	197	186	217	233	255	253	257
Reliability	64	107	75	98	140	111	128	127	128	67	31	33	33	34	34
Compliance	21	27	13	7	10	13	19	20	8	9	27	36	39	39	40
Non System	112	105	117	121	149	145	127	132	85	85	77	51	52	44	38
Total capex	342	434	532	576	646	719	759	784	652	558	542	511	518	505	499

Table 5-1: Capital expenditure 2004-05 to 2018-19<sup>99</sup> (\$million, 2013-14)

Our initial observation is that whilst there will be a reduction in Essential Energy's capital program over the forthcoming regulatory control period, relative to the average over the current period, the:

- Reduction is not as severe, when considered in the context of Essential Energy's spend in its base year (\$110M reduction between 2012/13 and 14/15), and
- Almost all of this reduction can be explained by a reduction in reliability related capital expenditure (it reduces from \$128M to \$31M).

In relation to the latter point, we note that one of the key drivers of its current reliability capital expenditure program was a change to the licence conditions of its predecessor organisation, Country Energy. At the time, Country Energy stated that '*the distribution reliability licence conditions are a key driver for reliability improvement investments*' and these required them to '*bring the forecast peak demand of high voltage distribution feeders, located in regional centres, under system normal operating conditions, to a target utilisation of at most 80 per cent of the thermal design rating by June 2014*<sup>101</sup>'.

In summary, there is prima facie evidence to suggest that Essential Energy would have been able to foresee, well in advance, that its capital expenditure program would be reducing materially in the next regulatory control period, simply as a result of the timing of when expenditure needed to be undertaken to comply with its Licence obligations (i.e., June 2014). We would observe that a prudent and efficient network service provider would have considered the transitory nature of this expenditure program when deriving the mix of resources that it would use to deliver that program.

In the absence of detailed information regarding the overall magnitude of the impact of this issue on Essential Energy's operating expenditure forecasts, or what in fact, it even entails (e.g., is it redundancy costs, or is it labour costs that were previously capitalised), it is difficult to provide a definite view as to whether or not these expenditures are likely to be meet the requirements of the Rules. However, the AER should give explicit consideration as to whether:

- It is reasonable to assume that Essential Energy should have been able to forecast this reduction in its capital expenditure program, and taken steps to prepare for it, including structuring the mix of resources that it would use to deliver what was a transitory expenditure program,
- Is any redundancy program consistent with the minimum requirements required under legislation (i.e., it is efficient), and

101 Country Energy, *Regulatory Proposal 2009-2014*, Page 128

- If the AER considers that some 'stranded costs' should be carried over into the forthcoming regulatory control period, then has Essential Energy, in deriving the level of stranded costs, given weight to the factors considered under the Rules such that only the prudent and efficient costs of providing standard control services are being provided for in their operating expenditure allowance. In saying this, we note that Essential Energy state themselves that they have 'responded in a measured way, balancing the interests of our employees, customers and shareholders'. Whilst it is entirely legitimate for Essential Energy to place equal weight on the interests of its employees if it chooses to, it is unclear whether the Rules, as currently constructed, place any weight on 'the interests of employees' when assessing the prudence and efficiency of Essential Energy's operating expenditure forecasts. If Essential Energy has placed more weight on the interests of its employees, over and above its minimum legal requirement, then it could be argued that under the Rules, this cost should not be funded by customers, but rather shareholders.