Issues Paper

Remitted decisions for NSW/ACT 2014–19 electricity distribution determinations Operating Expenditure

October 2017

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Invitation for submissions

Interested parties are invited to make submissions on this issues paper by 30 November 2017.

Submissions should be sent to: NSWACTremittal@aer.gov.au.

Alternatively, submissions can be sent to:

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Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy (June 2014), which is available on our website.[1]

1 https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

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1 Executive summary

This paper invites interested parties to make submissions on issues related to the remaking of our operating expenditure (opex) decisions for the electricity distribution determinations for Ausgrid, Endeavour Energy and ActewAGL (the distributors) for the 2014–19 regulatory control period (the 2014–19 remittal).

On 30 April 2015, we made final decisions on the determinations for the NSW and ACT electricity distributors for the 2014-19 regulatory control period. As part of these decisions, we did not accept each of the distributors' proposed opex forecasts. Instead, we substituted our alternative opex forecasts.

On 17 July 2015, the distributors sought merits review of our final decisions, including our decisions for opex, by the Australian Competition Tribunal (the Tribunal). The Public Interest Advocacy Centre (PIAC) also applied for review of our NSW final decisions. Additionally, the Commonwealth Minister for the Environment and Energy (Minister) intervened.

On 26 February 2016, the Tribunal found that it was open to us not to accept the distributors' opex forecasts, but had a number of concerns with how we derived our alternative opex forecasts. In particular, the Tribunal considered that we relied too heavily on the results of a single benchmarking model to derive our alternative opex forecasts. The Full Federal Court (the Court) subsequently affirmed this position on 24 May 2017 in its judicial review of the Tribunal's decision.

The AER's task for the 2014–19 remittal, with respect to opex, is therefore to reconsider the alternative opex forecasts that meets the opex criteria – which focus on efficient costs and realistic expectations of demand forecasts and cost inputs – under Chapter 6 of the National Electricity Rules (NER).

While we must remake the revenue determination as a whole for each distributor, taking into account interrelationships between the different contingent parts of our decision, this issues paper focuses on opex. Further consideration of the cost of debt as part of the 2014-19 remittal will occur through a separate process, most likely by way of us publishing an issues paper on the key issues outstanding for stakeholder consultation later this year.

This issues paper builds upon a roundtable meeting with key stakeholders, including distributor and consumer representatives, hosted by the AER on 16 August 2017 in which some key issues on opex were identified and discussed.[2]

The level of opex that the distributors have incurred to date for the 2014–19 regulatory control period (i.e. their 'revealed' costs) indicates they are converging toward the forecasts we set out for 2018-19 in our 2015 final decisions. All distributors, other than ActewAGL, have stated that they intend to achieve an opex level consistent with our final decision

2 AER, *NSW and ACT opex remittal roundtable (16 August 2017) summary note*, August 2017: https://www.aer.gov.au/communication/aer-hosts-nsw-act-electricity-distribution-network-revenue-roundtable

forecasts by 2018–19. This suggests that our final decision opex forecasts for 2018–19 may reasonably reflect an efficient level of opex for the 2014–19 regulatory control period consistent with the opex criteria. A key issue is whether the level of costs incurred by distributors to date can be assessed as prudent and efficient and at a sustainable level that will maintain the safety and reliability of services in the long-term interests of consumers.

Following from this, is the key issue of how we should characterise and assess the costs the distributors have incurred in the regulatory period in transitioning towards the level of opex consistent with the opex criteria. This raises the question of whether we should provide a distributor with a transition path allowance, which we discuss further in section 4.4.

We have termed these costs a "transition path allowance" and they generally constitute:

- transactional transition costs, which typically include the costs of making redundancy payments to reduce labour levels and terminating contracts early; and
- the inefficient costs that a distributor may continue to incur in the short term as it moves towards a lower level of opex, given it may not be able to transition immediately from its existing to that lower level of opex at the beginning of a regulatory control period.

This issues paper sets out a number of questions for consultation:

1. For distributors whose revealed costs to date or revised targets for 2018-19 are close to our final decision 2018-19 opex forecasts, do you consider it reasonable for us to rely on these revealed costs or revised targets to forecast opex? If we are not to rely on the distributors' revealed costs or revised targets, what other tools or approaches should we use to forecast opex ?

2. ActewAGL's revealed costs in the regulatory years 2015-16 and 2016-17 are less than the forecasts we determined in our final decision. There is no information or evidence before us that suggests ActewAGL's network has been adversely affected during the 2014-19 regulatory control period, including from a safety and reliability perspective. Based on this observation, does this suggest that ActewAGL's revealed costs in 2015-16 and 2016-17 represent a prudent and efficient level of opex? If we cannot rely on revealed costs in this case, what other tools or approaches should we use to forecast ActewAGL's opex?

3. In the context of the incentive regime established in Chapter 6 of the NER, and in the circumstances of transitioning from a higher level of opex to a materially lower level of opex (specifically transactional transition costs and the inefficient costs over and above the forecast), should:

   a) consumers solely bear those costs (that is, a distributor's forecast opex should include an amount for a transition path allowance); or

   b) distributors solely bear those costs (that is, a distributor's forecast opex should not include an amount for a transition path allowance); or

   c) those costs be allocated or shared between consumers and distributors (that is, a distributor's forecast opex should include a partial amount for a transition path allowance)?

4. How do you justify your answer to question 3 having regard to the opex criteria, the revenue and pricing principles (RPP) and the National Electricity Objective (NEO) and in particular, the long-term interests of consumers?

5. If you consider the costs that constitute a transition path allowance should be shared between consumers and distributors (i.e. that referred to in question 3(c)), how should these costs be allocated between the two? For example, should consumers fund the short-term transactional transition costs of distributors transitioning to an efficient level of opex (i.e. redundancy costs)?

6. Ausgrid, Endeavour Energy and ActewAGL (in 2014-15 only) have underspent against the capital expenditure (capex) forecasts we determined for them. Given we are required to have regard to the interrelationships between opex and capex, does this affect your answers to questions 3, 4 and 5, and if so, how?

7. An efficiency benefit sharing scheme (EBSS) applies to Endeavour Energy, which means it only bears around 30 per cent of the costs it considers constitutes a transition path allowance. Does this affect your answers to questions 3, 4 and 5, and if so, how?

2 Purpose

The purpose of this paper is to seek stakeholders' views on what we consider are the key issues before us in remaking our opex decisions for the NSW/ACT 2014–19 electricity distribution determinations in accordance with the directions of the Tribunal and the Court.

This paper is set out as follows:

- Section 3 provides background on the opex decisions we made in the final decision, and the subsequent decisions of the Tribunal and the Court directing us to remake those decisions.
- Sections 4.1 and 4.2 set out the legal framework in which we must remake the opex decisions, and the assessment approaches we intend to use.
- Section 4.3 presents information on the actual costs of the distributors that is available so far for the 2014-19 regulatory control period.
- Section 4.4 presents a discussion on whether the distributors should be provided with a transition path allowance as part of their opex forecasts.

2.1 Stakeholder roundtable meeting

To begin the remittal process, we held a roundtable meeting with key stakeholders on 16 August 2017. The purpose of the meeting was to seek views from stakeholders on what they considered are the key issues for us in remaking our opex decisions, and discuss options for how all stakeholders could work constructively in resolving these issues. A summary of the outcomes from the stakeholder roundtable meeting are available on the AER's website.[3]

There was some level of consensus on what stakeholders considered to be the key issues and external drivers relevant to the remaking of the opex decisions. These included:

- Affordability of electricity prices for consumers – participants agreed price smoothing should be used to the extent necessary to avoid price shocks.
- The remittal process – participants agreed that cost of debt decisions remitted back to the AER will need to be folded in with the remaking of the opex decisions at some point.
- The role of benchmarking – participants generally agreed that it is not practical for the AER to revise its benchmarking toolkit to set opex forecasts in the 2014–19 remittal.
- The use of revealed costs – some participants supported using revealed costs to forecast opex in the 2014–19 remittal.
- Transition costs – it was noted that the Tribunal did not reach a view on this issue.
- Reapplying the EBSS incentive framework – some participants expressed a preference to return to an EBSS-based incentive framework.[4]

3 AER, *NSW and ACT opex remittal roundtable (16 August 2017) summary note*, August 2017: https://www.aer.gov.au/communication/aer-hosts-nsw-act-electricity-distribution-network-revenue-roundtable

4 AER, *NSW and ACT opex remittal roundtable (16 August 2017) summary note*, August 2017:

2.2 Cost of debt

On 17 October 2017, the Tribunal handed down its decision in relation to the appeal of our revenue determinations for the Victorian electricity distributors and ActewAGL (Gas) Distribution, including on the issue of the cost of debt.[5] The issue of the cost of debt is still before the Full Federal Court in relation to our revenue determination for SA Power Networks. We are considering the outcome of the recent Tribunal decisions. We consider it prudent to take into account any further guidance that may arise from these decisions in remaking our cost of debt decisions. Further consideration of the cost of debt will occur through a separate process, most likely by way of an issues paper for stakeholder consultation later this year.

Given these circumstances, we will progress with our remaking of the opex decisions and incorporate our consideration of the cost of debt into the remittal process at a later stage. Therefore, this issues paper only discusses opex.

2.3 Next steps in the remittal process

We will likely publish an issues paper for stakeholder consultation on any key issues outstanding for cost of debt for the purpose of informing our decision-making processes prior to the making of draft decisions. Where no outstanding material issues remain, we will progress to the draft decision stage for the relevant distributor, at which point stakeholders will be provided with an opportunity to make submissions on the draft decision.[6]

2.3.1 Approach to remittal process for Essential Energy

Essential Energy has stated that maintaining price stability for its consumers is a priority and as part of a broader package, it will adopt most of the key parameters of our 2014–19 final decision, including opex and cost of debt. Accordingly, we think it is appropriate for us to proceed directly to the draft decision stage for Essential Energy's remittal. Stakeholders will have an opportunity to provide submissions on our draft decision for Essential Energy.

We expect Essential Energy will submit an updated proposal for the 2014–19 regulatory control period to us by early November 2017, which will be available on the AER's website. In turn, we expect to make a draft decision in late-November/ early December 2017 with stakeholder consultation occurring from the later part of 2017. A final decision is expected before the end of the first quarter of 2018.

As the NER does not prescribe a particular process for the remittal, nor did the Tribunal or the Court give any specific instruction regarding how we may conduct the remittal process, it is open for the NSW/ACT distributors to adopt an approach similar to Essential Energy or other approaches that may suit their needs while affording procedural fairness and satisfying our engagement guidelines.

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https://www.aer.gov.au/communication/aer-hosts-nsw-act-electricity-distribution-network-revenue-roundtable

5 *Application by ActewAGL Distribution* [2017] ACompT2.

6 Consequential to our opex decision for ActewAGL, we must also remake decisions for ActewAGL's service target performance incentive scheme (STPIS), alternative control metering services annual charges and the classification of metering services.

2.3.2 Approach to remittal process for Ausgrid, Endeavour Energy and ActewAGL

Based on recent discussions with Ausgrid, Endeavour Energy and ActewAGL, we believe there are still material issues for remaking our opex decisions that will need to be further consulted upon. This issues paper represents the next step in us consulting on what we see as the key opex issues for remittal for these distributors.

As noted above, the issue of the cost of debt is currently before the Court and has been the subject of the recent Tribunal decisions for the Victorian electricity distributors and ActewAGL (Gas) Distribution. These decisions will likely inform us and other stakeholders on the approach for remaking our cost of debt decisions on remittal. Depending on the nature of these decisions, it may be appropriate to proceed with an issues paper on the cost of debt to obtain further information and views from stakeholders, prior to any draft decision.

This suggests that, at this stage, draft decisions on opex and the costs of debt for Ausgrid, Endeavour Energy and ActewAGL will be released around June 2018 for public consultation. Based on this indicative timeline, we expect to make the final decisions for the 2014-19 regulatory control period before the end of 2018.

3 Background

To contextualise our remittal task for the 2014-19 regulatory control period, this section presents background information on:

- our opex decisions for NSW and ACT distributors;
- merits review of our final decisions; and
- judicial review of the Tribunal's decisions in respect of our final decisions.

3.1 The AER’s operating expenditure decisions for the NSW and ACT distributors

The AER is required to determine the revenue allowance for distributors under the NER. As part of the transitionary arrangements for major changes to national rules for the regulation of distributors made in November 2012, the Australian Energy Market Commission (AEMC) deferred the full regulatory determination process for NSW/ACT distributors' 2014-19 regulatory control period. On 16 April 2014, as part of the transitional arrangements, we determined a placeholder revenue allowance for the 2014-15 transitional regulatory control period. In May 2014, we received the NSW/ACT distributors' regulatory proposals for the 2014-19 regulatory control period, after which the full determination process commenced. We assessed the revenue allowances for the whole 2014-19 regulatory control period, and trued up any difference between the placeholder revenue allowance and revenue requirement for the transitional year.

On 30 April 2015, we published final decisions for the 2014–19 NSW/ACT distribution determinations. In these decisions, we did not accept the distributors’ proposed opex forecasts, and instead substituted our own alternative opex forecasts.

The difference between our alternative opex forecasts and the distributors’ proposals was primarily due to the material inefficiency that we identified on the basis of the information available to us at the time. That information included:

- the distributors’ proposals, which identified issues such as “stranded labour” and the need to restructure towards a more efficient workforce;
- the economic benchmarking techniques with various adjustments (developed with a consultant, Economic Insights) we applied, that showed the distributors were operating inefficiently relative to other network service providers in the National Electricity Market (NEM);
- detailed reviews of the distributors’ labour cost practices (by consultants Deloitte and EMCa), which found the distributors had too many permanent employees operating under Enterprise Bargaining Agreements (EBA); and
- a detailed review of the vegetation management practices of Essential Energy and ActewAGL, conducted by us and our consultant EMCa, respectively, which found that their practices were not consistent with those of a prudent service provider acting efficiently.

On the basis of this information, we found the actual opex incurred by Ausgrid, Essential Energy and ActewAGL in their proposed base year of 2012-13, was materially greater than what a prudent and efficient network service provider would incur in delivering safe and reliable network services to customers. We, therefore, found that the revealed costs in 2012-13 could not be used as a basis to forecast opex during the 2014–19 regulatory control period.

Where we are not satisfied that a forecast estimate is efficient, the NER requires us to replace it with one that we are satisfied would reasonably reflect the opex criteria.[7] In this instance we estimated base year opex for Ausgrid, Essential Energy and ActewAGL using the results of our economic benchmarking model (the 'SFA Model'), with appropriate adjustments for the benchmark comparison point, operating environment factors and the trending of the average efficient opex to the base year.

In using our model, we had regard to Economic Insights' expert advice, including the relative advantages and disadvantages of the alternative economic benchmarking techniques considered. The result of this approach was the reduction of the base year opex for Ausgrid by 24 per cent, Essential Energy by 26 per cent and ActewAGL by 33 per cent.

In the case of Endeavour Energy, we did not find any evidence of material inefficiency in the actual opex it incurred in its proposed base year. However, Endeavour Energy proposed a significant opex increase (a step change) for vegetation management costs that, if included, did not satisfy us that the total forecast opex would reasonably reflect the opex criteria. Our findings were that the costs of providing a safe and reliable network service with comparable vegetation management obligations were already reflected in Endeavour Energy's base opex. A material increase in opex for vegetation management costs to meet Endeavour Energy's existing regulatory obligations was therefore unnecessary and inconsistent with the opex criteria.

Table 1 shows the total difference between the distributors' opex proposals and our final decisions.

Table 1 Differences between NSW/ACT opex proposals and AER final decisions — total opex forecast for 2014-19 regulatory period

$million, 2013-14	Ausgrid	Essential	Endeavour	ActewAGL
Distributor forecast (revised proposal)	2,679.3	2,306.6	1,465.6	371.2
AER final decision	1,992.9	1,615.3	1,218.3	240.6
Differences	686.4	691.3	247.3	130.6

Source: AER analysis.

Note: Numbers may not add up due to rounding.

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

3.2 Merits review

On 17 July 2015, the distributors and PIAC sought merits review of our final decisions, including in relation to the forecast opex allowances that we included in the distributors' total revenues.[8] The Commonwealth Minister also intervened.

3.2.1 Distributors' grounds for review

The distributors argued that our opex forecasts were too low. Specifically, they raised issue with our:

- use of benchmarking to reject their proposed opex forecasts and determine our alternative opex forecasts;
- findings on labour costs, including that an EBA is not a regulatory obligation or requirement and to not provide a transition path allowance to cover redundancy payments;
- findings on the vegetation management practices of Essential Energy and ActewAGL; and
- rejection of vegetation management step-change Endeavour Energy had proposed.

3.2.2 PIAC's grounds for review

PIAC, on the other hand, supported our use of benchmarking. However, it argued that our opex forecasts were too high, specifically raising issue with our:

- lowering of the benchmark comparison point between the draft and final decisions; and
- operating environment factor (OEF) adjustments, specifically in relation to immaterial OEFs, the positive adjustment for directionally ambiguous OEFs, our comparison of OEFs against the average of the top five networks and treating bushfire risk as an immaterial cost advantage for the NSW networks.

3.2.3 Tribunal's decisions

On 26 February 2016, the Tribunal handed down its decisions.[9] The Tribunal remitted our decisions back to us to be remade, in accordance with its orders on:

- the return on debt;
- the value of imputation credits (gamma); and
- opex (and for ActewAGL, the implications of this for the Service Target Performance Incentive Scheme).[10]

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8 The distributors had also sought merits review on other elements of our decision including the return on equity and debt , the value of imputation credit (gamma), and the efficiency benefit sharing scheme.

9 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1; *Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy* [2016] ACompT 2; *Applications by Public Interest Advocacy Centre Ltd and Essential Energy* [2016] ACompT 3; *Application by ActewAGL Distribution* [2016] ACompT 4.

10 The Tribunal upheld the distributors' challenges to the AER's allowances for returns on debt, the value it set for gamma

Table 2 sets out the key passages in the Tribunal's reasons that underlie its direction for us to remake our opex decision.

Table 2 Key passages from the Tribunal's reasons

The AER's decision to reject distributors' opex proposals
The Tribunal found that it was open to the AER to not accept the distributors' opex forecasts under cl 6.5.6(c). The Tribunal stated:[11] As a first step in its consideration, the AER was required to decide whether it was satisfied that the total of the forecast opex in the Revised Regulatory Proposals of each of the DNSPs reasonably reflected each of the operating expenditure criteria set out in r 6.5.6(c). The AER's analysis of the Networks NSW and ActewAGL Revised Regulatory Proposals led to it expressing concerns about a number of components or elements of those proposals. The Tribunal is not persuaded, having regard to those concerns, that the AER's lack of satisfaction on that question exposes a ground of review. There was material upon which it could have reached that conclusion… …Consequently, the Tribunal does not consider that the step taken by the AER under r 6.5.6(d) involved error on its part so as to enliven any grounds of review under s 71C of the NEL.
Use of benchmarking
The Tribunal found that the AER erred in deriving its substitute opex forecast under cl 6.12.1(4). The Tribunal considered the AER had placed too much weight on the economic benchmarking model in deriving its substitute opex forecast. The Tribunal stated:[12] Having regard to the DNSPs and PIAC's submissions as a whole the Tribunal concludes that the AER's reliance on the EI model failed to discharge its obligations under rr 6.5.6 and 6.12.1(4). The Tribunal's areas of concern were:[13] • The inadequacy of the RIN data set and comparability issues (including estimated data). • The use of overseas data in the modelling • The lowering of the 'efficiency frontier' between the draft and final decision (which suggested that the AER was not confident in the results of the EI model). • The application of OEFs. In several instances, the Tribunal raised concerns with the application of benchmarking "in the context of this being the first time the AER used economic benchmarking to set opex allowances".[14] The Tribunal also found that the timeframe available did not permit us to consult adequately

(which was later set aside by the Federal Court in judicial review) and ActewAGL's Service Target Performance Incentive Schemes.

11 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [468] and [469].

12 Ibid., [495].

13 Ibid., [467].

14 Ibid., [316], [467], [480] and [496].

to test the benchmarking data and rigorously examine the distributors' consultants reports, some of which proposed alternative benchmarking models (see para 496(b)).
Bottom-up quantification
The Tribunal stated that the AER should have performed "reasonableness checks" on its benchmarking results with quantitative bottom-up analysis of the distributors' opex forecasts components.[15] The Tribunal did not accept that the AER's labour and vegetation management reviews provided quantitative support for inefficiencies in labour and vegetation management costs. The Tribunal also stated:[16] …the AER should not have cast aside its previous practice of conducting bottom-up reviews in favour of the emphasis it placed on benchmarking.
Labour costs and enterprise bargaining agreements
The Tribunal did not agree that EBAs amounted to 'regulatory obligations or requirements'. However, it accepted the distributors were bound by them as a matter of law:[17] Although EBAs may lack either the NEL's s 2D jurisdictional foundation or the genus of a safety or reliability standard etc of a r 6.5.6(a)(3) "regulatory requirement or obligation", the Networks NSW DNSPs are bound by their EBAs as a matter of law. The Tribunal also stated: [18] As Networks NSW submit, Ausgrid, Essential and Endeavour are bound by the EBAs and remain bound by them and they should not be viewed as an endogenous managerial choice. At least not in circumstances where the AER has quite radically shifted from an itemised bottom-up approach to assessing opex to benchmarking total opex per se – particularly where that benchmarking has not been exposed to the rigors of the consultation the NEL and NER envisage for such a radical change. …having regard to the regulatory prescriptions, the Tribunal does not accept that it may, by the use of the EI model, simply select the measurement of efficiency which it did in this respect without regard to the obligations under the EBAs as they presently exist. Over time, and probably during the new current regulatory period, any such inefficiencies as the AER considers to exist may progressively be reduced by the reduction in employee numbers to what the AER considers to be the efficient number, and any allowances under the EBAs (as they expire) which the AER considers to be inefficient may also by the same elapse of time be reduced to an efficient level. The Tribunal further opined that "it is the policy of the legislative arm of government that, to the extent that the EBA's are (if they are) an inefficient imposition on the electricity network respondents, nevertheless they are a cost to be borne by consumers".[19] As part of its discussion on the distributors' proposed plans to reduce their staff numbers, the Tribunal stated that the AER should consider the effectiveness of these plans as they are implemented within the 2014-19 regulatory period: [20]

15 Ibid., [408].
16 Ibid., [389].
17 Ibid., [427].
18 Ibid., [434] and [436].
19 Ibid., [436].
20 Ibid., [442].

As the 2015 Deloitte Labour Report contended that the NSW DNSPs did not have an efficient workforce in the base year and compared employee numbers across the regulatory control period with other DNSPs, the AER will have to consider how the efficiency programs implemented by the NSW DNSPs into the 2014-19 regulatory control period have been effective.
Transition path allowance
The Tribunal did not form a position on the distributors' arguments that the AER should have provided an opex 'transition path'. However, the Tribunal stated: [21] When the AER revisits and re-determines the opex allowance, it will have to consider the costs involved in transitioning. It will do so at a time, and in relation to revenue streams, which will require it to make a fresh decision. The Tribunal is anxious not to inhibit the AER at this point in exercising its discretion in that regard.
Endeavour Energy's vegetation management step-change
The Tribunal did not necessarily find error in the AER's rejection of Endeavour Energy's increase in vegetation management costs. Rather, the Tribunal considered the AER should reconsider this issue with the context of remaking the opex decisions:[22] The Tribunal makes more general orders than it might otherwise because it does not know what might be the consequences of the AER's assessment of the efficiency of the claimed opex when it has undertaken the modelling and benchmarking which the Tribunal canvassed in the PIAC-Ausgrid Decision. Depending on the outcome of that, the AER may adhere to that starting point or revisit it. It should, in any event, be given the opportunity to consider that, and to revisit the VM Expenditure and Redundancy Expenditure claimed in the more general context of the opex expenditure claimed.

3.3 Judicial review

On 24 March 2016, we applied to the Full Federal Court for judicial review of the Tribunal's decisions on value of imputation credits (gamma), return on debt and opex. The crux of our argument was that the Tribunal misinterpreted the scope of the reviewable errors in s 71C of the National Electricity Law (NEL).

On 24 May 2017, the Court dismissed our appeal and upheld the Tribunal's decision in relation to opex and cost of debt. It upheld the AER's appeal in relation to gamma. In relation to opex, the Court found that reading the decision as a whole, the Tribunal had identified an 'independent and freestanding error' with our reliance on the SFA model to determine opex. In particular, the Court stated:[23]

> It is true that the Tribunal said that underlying its view at the general level were a series of concerns about the EI Model which concerns it identified, but it also said that there were underlying elements to the EI Model which meant that the available Australian data was not sufficiently extensive for appropriate modelling and the AER should not have placed the weight it did on the output of the EI Model.

The Court considered each issue before the Tribunal: the benchmarking Regulatory Information Notice (RIN) data, the use of overseas data, the lowering of the benchmark

21 Ibid., [494].

22 *Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy* [2016] ACompT 2, [35].

23 *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79, [285].

comparison point, and the OEFs. In each instance, it found that the Tribunal did not err in reaching its conclusions.[24] In relation to labour costs, the Court found that it was open for the Tribunal to find that the benchmarking results were not sufficiently reliable to draw a conclusion that the NSW service providers' labour practices were inefficient and that that was attributable, or partly attributable, to the EBA.

The Court found that the Tribunal did not err in finding error in an approach that simply characterised an obligation as endogenous and to be ignored or as exogenous and to be considered and said that a closer analysis was required.[25]

The Court also stated that whilst the Tribunal was incorrect to state that "it is the policy of the legislative arm of government that, to the extent that the EBA's are (if they are) an inefficient imposition on the electricity network respondents, nevertheless they are a cost to be borne by consumers", this statement should not be read by itself but instead in the context of the Tribunal's above findings in relation to labour costs.[26]

In relation to implementing the Tribunal's directions, the Court did not consider that they were uncertain. Nor did the Court consider that the Tribunal is obligated to direct us as to the decision we must make.[27] In relation to the Tribunal's direction for us to conduct a bottom-up review, the Court stated:[28]

> … it is for the AER to determine the nature and scope of the bottom-up review provided that it otherwise complies with the NEL and the NER and makes it decision consistently with the criticisms in the Tribunal's reasons about the original methodology.

3.4 Undertakings provided by the distributors

During the time the appeal processes were underway, all of the distributors submitted their annual pricing proposals consistent with our final decisions for the 2015–16 regulatory year, which we approved. [29]

However, following the Tribunal's decision and our subsequent judicial review application, there was considerable uncertainty regarding the effect of the Tribunal's decision on pricing and non-price matters.

In May 2016, we accepted undertakings given by the distributors under section 59A of the NEL that set out how network revenues and tariffs will be determined in 2016–17.[30] ActewAGL, Ausgrid and Endeavour Energy's Network Use of System (NUOS) Tariffs in

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24 Ibid., [295]-[339].

25 Ibid., [369] and [370].

26 Ibid., [371].

27 Ibid., [305], [321], [326], [339] and [372].

28 Ibid., [378].

29 In May 2014, the NSW/ACT distributors had submitted to us their 2014–15 annual pricing proposals for their respective networks. We assessed these proposals for compliance with Part 1 of the NER and our 2014–15 placeholder distribution determinations. Subsequently, we approved each of the distributors' 2014–15 pricing proposals.

30 Ausgrid, *Ausgrid enforceable undertaking*, May 2016. Endeavour Energy, *Endeavour Energy enforceable undertaking*, May 2016. ActewAGL, *ActewAGL enforceable undertaking*, May 2016. Essential Energy, Essential Energy enforceable undertaking, May 2016.

2016–17 were set as their 2015–16 approved tariffs, adjusted to include changes in the consumer price index (CPI) in 2015–16.[31]

As of May 2017, the Court had not yet handed down its decision, so we accepted further undertakings given by the distributors to establish new interim arrangements to govern the setting of network tariffs in 2017–18.[32] ActewAGL, Ausgrid and Endeavour Energy's NUOS Tariffs in 2017–18 were also set as their 2015–16 approved tariffs, adjusted to include changes in the CPI in 2015–16 and 2016–17.[33]

The effect of these undertakings is that the revenues recovered by the distributors during 2016–17 and 2017–18 are likely to differ from that which they are entitled to recover after we remake their opex decisions. The next section discusses how and when these revenues may be recovered from customers.

AEMC rule change introduced in August 2017

Under the regulatory regime in Chapter 6 of the NER, the difference between the revenue a distributor actually recovers and that which it is entitled to recover, is either recovered within the current regulatory period or the first year of the subsequent regulatory period. If the difference is material, recovering such differences over a short timeframe (for example, one regulatory year) may result in large prices shocks for consumers.

On 1 August 2017, the AEMC made a rule to allow the distributors to recover such differences over both the 2014–19 and subsequent regulatory control periods.[34] The rule allows us to make revenue adjustments to smooth revenue across, or allocate it between, these regulatory control periods. Such adjustments are given effect through the pricing proposal and distribution determination processes.

This rule does not affect the quantum of the revenue the distributors will be permitted to recover in the remittal decision but the time period over which they can recover it from customers. The intent is to minimise the potential for significant fluctuations in retail prices that consumers may experience from one period to the next.

31 Network Use of System (NUOS) Tariffs traditionally include distribution use of system tariffs and transmission use of system (TUOS) tariffs. We included TUOS tariffs in the undertakings to ensure price stability and predictability.

32 Ausgrid, *Ausgrid enforceable undertaking*, 17 May 2017. Endeavour Energy, *Endeavour Energy enforceable undertaking*, March 2017. ActewAGL, *ActewAGL enforceable undertaking*, 17 May 2017. Essential Energy, *Essential Energy enforceable undertaking*, 8 May 2017.

33 These enforceable undertakings also obliged the ACT and NSW distributors to continue to provide network services consistent with the non-price terms and conditions of their 2015–19 electricity distribution determinations.

34 AEMC, *Participant derogation - NSW DNSPs revenue smoothing, Rule Determination*, 1 August 2017. AEMC, *National Electricity Amendment (Participant derogation - NSW DNSPs Revenue Smoothing) Rule 2017 No. 6*.

4 The remittal task: remaking the opex decisions

In this section, we outline the key factors relevant to the remaking of the opex decisions, namely:

- the legal framework in which we must remake the opex decisions;
- the assessment approaches we intend to use;
- the available revealed costs information for the distributors for the 2014–19 regulatory control period; and
- factors relevant to whether the distributors should be provided with a transition path allowance as part of their opex forecasts.

4.1 The legal framework

4.1.1 The Tribunal's direction

The Tribunal provided us with the following direction in relation to opex for Ausgrid:[35]

> The AER is to make the constituent decision on opex under r 6.12.1(4) of the National Electricity Rules in accordance with these reasons for decision including assessing whether the forecast opex proposed by the applicant reasonably reflects each of the operating expenditure criteria in r 6.5.6(c) of the National Electricity Rules including using a broader range of modelling, and benchmarking against Australian businesses, and including a "bottom up" review of Ausgrid's forecast operating expenditure;

The Tribunal also provided corresponding directions for Endeavour Energy, Essential Energy and ActewAGL.[36]

4.1.2 The NER and NEL requirements

The rules in the NER and provisions in the NEL that govern our assessment of opex remain unchanged on remittal.

As the Tribunal refers to in its directions, we must remake our opex decision under clause 6.12.1(4) of the NER. This means we must either accept each distributor's proposed opex forecast, or reject it and determine our own substitute estimate, in light of all the information available to us. Clause 6.5.6 of the NER sets out the opex objectives, opex criteria and opex factors, under which we must either accept the distributor's proposal, or reject and substitute our own estimate of a forecast opex.

Other legislative requirements relevant to remaking our opex decision include the National Electricity Objective (NEO), the revenue and pricing principles (RPP), the definition of a regulatory obligation or requirement, and any interrelationships with other related components of a distribution determination. The NEO is relevant because we are required to

35 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, direction 1(a).

36 *Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy* [2016] ACompT 2, direction (1)(a); *Applications by Public Interest Advocacy Centre Ltd and Essential Energy* [2016] ACompT 3, direction (1)(a); *Application by ActewAGL Distribution* [2016] ACompT 4, direction (1)(a).

make a distribution determination (of which the forecast opex is a part) that will or is likely to contribute to the achievement of the NEO to the greatest degree.[37] The RPP are relevant because we must take them into account in exercising discretion, as is the case in remaking our opex decision.[38] The expression, a regulatory obligation or requirement, is referred to in the opex objectives.[39] We must also take into account any interrelationships between forecast opex and any other related component of a distribution determination.[40] This consideration is similar to the opex factor that requires us to consider the substitution possibilities between opex and capex.[41]

In summary, taking into account all of these requirements means that we must identify a level of opex that is efficient and prudent and at a level that sustainably maintains the safety and reliability of the network in the long-term interests of consumers.

Finally, as part of remaking our opex decision, we must determine whether, or the extent to which, we provide the distributors with a "transition path allowance". This issue arose in submissions made by Ausgrid, Essential Energy and ActewAGL in response to our substitute estimates in the final decisions being materially lower than their proposed forecasts. Specifically, they submitted that we should provide them with this allowance to cover the costs they would incur in transitioning from their existing inefficient level of opex to another lower (efficient) level of opex. Generally, these costs can be characterised as being either:

- transactional transition costs, which typically includes the costs of making redundancy payments to reduce labour levels and terminating contracts early; and
- the inefficient costs that a distributor may continue to incur in the short-term as it moves towards a lower level of opex, given it may not be able to transition immediately from its existing to that lower level of opex at the beginning of a regulatory control period.

The issue of a transition path allowance is further discussed at section 4.4.

4.2 Operating expenditure assessment

The total forecast opex determined (be it the distributor’s proposal or our substitute estimate) forms part of a total revenue allowance which a distributor may recover during a regulatory control period. It is important to recognise that we are required under the NER to make decisions on the total forecast opex, and not the individual opex projects or categories which may make up the total opex, as the day-to-day decisions of how a distributor operates its network is best left to that distributor.

Setting forecast opex is part of the incentive and ex-ante based regulatory regime established in Chapter 6 of the NER. This type of regulation is based on incentivising network businesses to provide services as efficiently as possible, whilst fulfilling their reliability and security obligations.

37 NEL, ss. 7 and 16(1)(d).
38 The RPP that are directly relevant to remaking our opex decision are set out at NEL, ss. 7A(2), 7A(3), 7A(7) and 16(2).
39 NEL, s. 2D; NER, cll. 6.5.6(a)(2) and 6.5.6(a)(3).
40 NEL, s. 16(1)(c).
41 NER, cl. 6.5.6(e)(7).

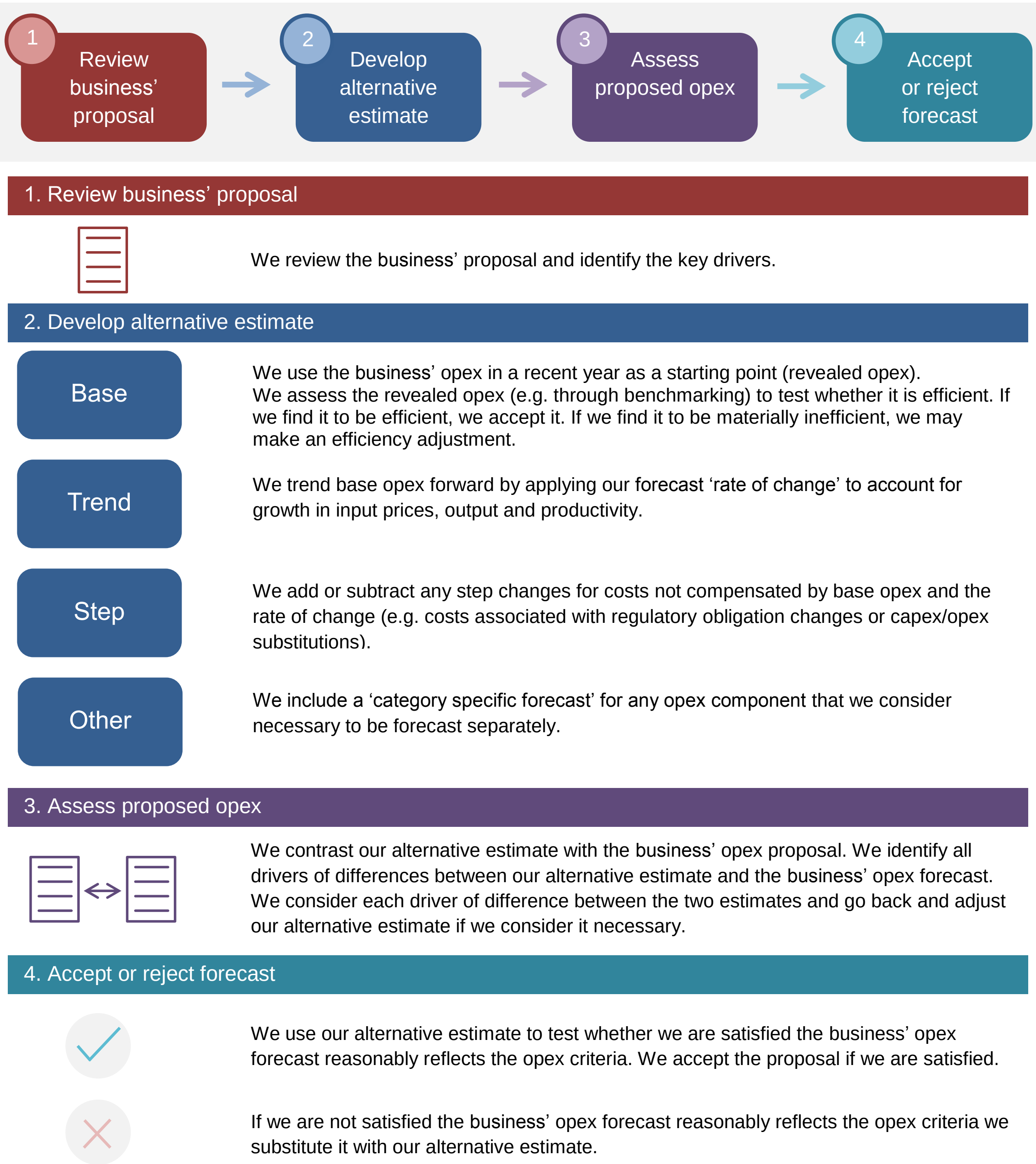
A network business' revenue allowance is "locked in" at the beginning of a regulatory control period. With revenue allowance locked in, the network business is incentivised to provide network services at the lowest possible cost (while meeting relevant regulatory obligations) because its returns are determined by its actual costs of providing services. If a network business is able to reduce its costs to below the estimate of efficient costs, the savings are shared with customers in future regulatory control periods by allowing us to set lower opex forecasts based on revealed costs.

Therefore, so long as we do not identify any material inefficiency in a distributor's revealed costs, our preference is to rely on these costs in assessing and determining an opex forecast.

In assessing and determining an opex forecast, we generally apply a 'top-down' forecasting method, known as the 'base–step–trend' approach.

Figure 1 summarises our assessment approach.

Figure 1 Our opex assessment approach



In remaking the opex decisions, we can potentially use a variety of assessment approaches to estimate an efficient and prudent level of opex. These approaches include:

- revealed costs (including taking into account the actual opex the distributors have incurred in the 2014–19 regulatory period so far);
- economic benchmarking; and
- bottom-up assessments.

Each approach is discussed below.

4.2.1 Revealed costs

As we discussed above, the setting of a total revenue allowance, which includes a forecast of efficient opex over the regulatory control period, is part of the incentive-based and ex-ante regulatory regime established in Chapter 6 of the NER. This framework partially addresses the information asymmetries between the distributors and us as to what the distributors' true efficient costs may actually be.

Opex is largely recurrent and stable at a total level between regulatory periods. For recurrent expenditure, we prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts. If a distributor operated under an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the distributor requires in the future. Underpinning this 'revealed cost approach' is the assumption that a distributor has responded to the incentive to achieve efficiencies and spend less than the revenue allowance (and will continue to do so) whilst maintaining the safe and reliable operation of its network under existing regulatory obligations.

The ex-ante incentive regime provides an incentive to improve efficiency (that is, by incurring costs less than our forecast) because distributors can retain cost savings made during the regulatory control period. Where we apply the EBSS and use a distributor's revealed costs to forecast opex, the distributor retains approximately 30 per cent of any efficiency gains made. In the case where an exogenous method, such as benchmarking or a bottom-up cost review, is used or expected to be used to determine a forecast of efficient costs, a distributor will have a very strong incentive to reduce its costs as it will bear 100 per cent of any inefficient costs as well as retain 100 per cent of any efficiency gains made. The distributors have stated that they have faced a very strong incentive to reduce costs over this regulatory period given the AER's opex forecasts were significantly below their actual costs at the start of the 2014–19 regulatory control period.[42]

As outlined in our Expenditure Assessment Forecast Guideline, our preferred approach for forecasting opex is to use the revealed cost approach.[43] Undertaking these remittals now presents us with the opportunity to take into account the revealed costs the distributors have incurred to date since our final decisions made in 2015. There will be at least three years of actual cost data for the 2014–19 regulatory control period by the time we remake our opex decisions.

One pertinent issue is whether the level of costs incurred by distributors to date can be assessed as prudent and efficient and at a sustainable level that will maintain the safety and reliability of services in the long-term interests of consumers. All distributors, other than ActewAGL, have stated that they intend to achieve an opex level consistent with our final decision forecasts by 2018–19. This suggests that our final decision opex forecasts for 2018–19 may reasonably reflect an efficient level of opex for the 2014–19 regulatory control period consistent with the opex criteria.

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42 AER, *NSW and ACT opex remittal roundtable (16 August 2017) summary note*, August 2017: https://www.aer.gov.au/communication/aer-hosts-nsw-act-electricity-distribution-network-revenue-roundtable

43 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.p.31

Following from this, is the key issue of how we should characterise and assess the costs the distributors have incurred in the regulatory period in transitioning towards the level of opex consistent with the opex criteria. This raises the question of whether we should provide a distributor with a transition path allowance, which we discuss further in section 4.4 below.

We discuss the cost information for the 2014–19 regulatory control period currently available to us in section 4.3.

4.2.2 Economic benchmarking

As noted above, we prefer to use revealed (past actual) costs as the starting point for assessing and determining efficient forecasts.

In recent years, we have expanded our regulatory toolkit to make greater use of benchmarking, which is a way of determining how well a network business is performing against its industry peers and over time. Benchmarking can:

- improve the effectiveness of the regulatory process by enhancing the information available to us;
- give us and stakeholders an alternative source of comparative information about the costs of operating a business to test the businesses' proposals; and
- provide us with some insight into whether or not there are material inefficiencies in a business' base opex and, therefore, represents a good basis for forecasting future opex.

We have used benchmarking to investigate whether an adjustment to base opex is required — that is, whether there is evidence of 'material inefficiencies' in a network business' base opex. If the business is materially inefficient compared to its peers, the revealed cost approach may not be appropriate. Reliance on revealed costs in these circumstances could yield an outcome inconsistent with the opex criteria.

Except for Endeavour Energy, the economic benchmarking we applied in our 2015 final decisions demonstrated material inefficiency in the revealed costs of each distributor's proposed base year opex (2012–13). This was part of the reason why we did not accept the distributors' proposed opex forecasts. However, despite accepting that the distributors' proposals did not meet the opex criteria (based on their revealed costs), the Tribunal concluded that we relied too heavily on our benchmarking analysis to determine our substitute estimates in circumstances where economic benchmarking was being used for the first time to set opex forecasts and the SFA model we applied had limitations in relation to its outputs and inputs, data used and other uncertainties.[44]

Whilst we are mindful of the Tribunal's findings, it is not practical for us to now revise our economic benchmarking analysis and apply it in remaking our opex decisions. The benchmarking techniques and data we have utilised to date are the best available at this time, and were developed following an extensive public consultation process as part of our Better Regulation program during 2013.[45] Any substantive revisions would therefore involve

44 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [495] and [496].

45 As part of its Better Regulation program during 2013, the AER hosted 18 workshops concerning the assessment of

a considerable amount of development work and time to consult with industry, consumer groups and other stakeholders.

Further, at our stakeholder roundtable meeting in August 2017, stakeholders stated a clear preference for us to remake our decisions in a timely manner and recognised that revisiting our benchmarking is not possible without delaying the remaking of our opex decisions significantly.[46]

We note that, separate to this remittal process, we remain committed to refining our economic benchmarking analysis as part of our program of continual improvement of our regulatory toolkit.

Given the circumstances, we propose to use our benchmarking techniques (beyond the SFA model) with updated data for the most recent years, to cross-check the revealed costs or proposed cost targets of the distributors. This will give stakeholders some level of assurance as to whether the distributors' revealed costs are materially inefficient or not.

4.2.3 Bottom-up assessments

In directing us to perform a bottom-up assessment of the distributors' proposals, the Tribunal and Court did not specify what form of bottom-up assessment we need to undertake in remaking our opex decisions. The Court stated that the issue of what form and scope of bottom-up review is a matter for us to consider.[47]

There is no clear definition of what constitutes a bottom-up assessment. Generally, a bottom-up approach involves a detailed review that assesses discrete opex projects, items or categories of opex, involving reliance on engineering and managerial expertise, economic analysis, or more granular forms of benchmarking (for example, at the category analysis level). In order to assess whether the total opex forecast is consistent with the NER requirements, aggregating the relevant items is necessary.

A bottom-up assessment also involves us, to some extent, making inferences about how a distributor should operate its network. This is at odds with our decision on the total opex forecast, how the incentives under the regulatory regime operate, and the underlying premise that the day-to-day operation of a network is a matter best left to the distributor. Further, using bottom-up assessments to construct a total opex forecast in most cases is a costly and resource-intensive process, particularly in light of the information asymmetries between the distributor and us.

In certain circumstances, undertaking a bottom-up assessment of a particular opex item or category may be warranted as part of assessing a total opex forecast. We intend to apply some form of bottom-up analysis appropriate to the specific circumstances for each of the

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forecast expenditure. Seven of these workshops sought feedback on the appropriate outputs, inputs and operating environment variables to be used in economic benchmarking models. The workshops also sought feedback on the necessary data reporting mechanisms and how economic benchmarking would be used in assessing DNSPs' expenditure proposals. In addition, the AER also consulted on the development of the Economic Benchmarking RINs bi-laterally with businesses and through workshops.

46 AER, *NSW and ACT opex remittal roundtable (16 August 2017) summary note*, August 2017.

47 *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79, [378].

distributors. Where the revealed costs of a distributor are likely to reflect a prudent and efficient level of opex that meets the opex criteria, and is at a sustainable level that will maintain the safety and reliability of services in the long-term interests of consumers, any bottom-up assessment warranted may be minimal in scope and nature. In cases where the revealed costs do not reflect a prudent and efficient level of opex that meets the opex criteria, we may undertake more comprehensive and detailed bottom-up assessments.

4.3 Available cost information

In this section, we present the distributors' total opex and capex information currently available to us.

4.3.1 Actual opex incurred in the 2014–19 regulatory control period

4.3.1.1 Ausgrid

Table 3 shows the differences between the opex Ausgrid incurred since 2014–15 and the forecasts in our final decision.[48]

Table 3 Difference between Ausgrid actual opex and final decision

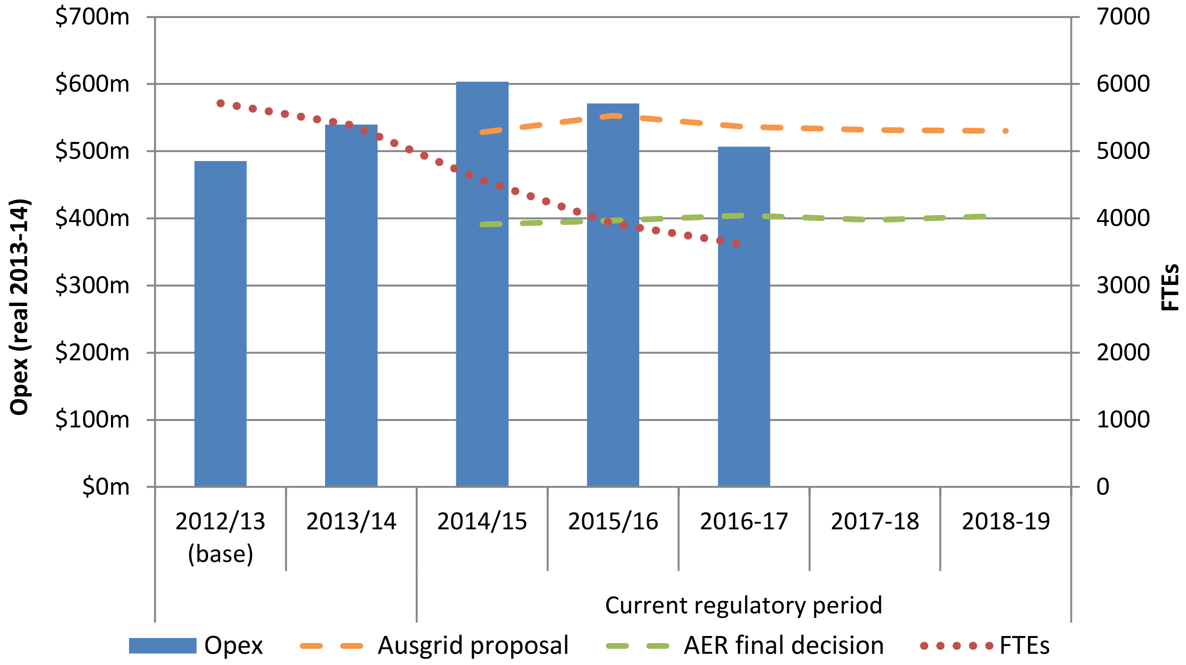
$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Ausgrid revised proposal	528.4	553.2	536.1	531.7	529.9
Actual opex	645.9	578.1	513.0	N/A	N/A
AER final decision	390.8	396.6	404.3	397.5	403.6
Difference	255.1	181.5	108.7	N/A	N/A

Source: AER final decision; Annual RIN; Ausgrid response to AER information request; Ausgrid annual report

Figure 2 shows that Ausgrid's annual opex has increased since the 2012–13 base year, peaking at 23 per cent higher in 2014–15 before declining to its current level in 2016–17, where it is 4 per cent above the base year. Ausgrid's actual opex in 2016–17 remains above our 2015 final decision opex forecast. Ausgrid has reduced its permanent full-time employees (FTEs) by 37 per cent over this period.

48 The distributors have each provided us with estimates of their 2016-17 actual opex, which have not yet been reported to the AER within annual regulatory information notices. These figures are the best available estimates of actual opex in 2016-17. However, they are still subject to auditing and finalisation by each distributor.

Figure 2 Ausgrid actual opex, AER forecast opex, and Ausgrid proposed opex for 2014–19, including movements in FTEs



Source: AER final decision; Annual RIN; Ausgrid response to AER information request; Ausgrid annual report

Note: Actual opex has been normalised by excluding metering and ancillary costs, and opex pass-throughs.

Ausgrid is currently undertaking a transformation program to reduce costs, as outlined in its 2015–16 annual report and its expenditure forecasting methodology for its 2019–24 regulatory proposal.[49] Ausgrid proposes to transition to an efficient operating cost base by 2017–18 and this opex will form the basis for its opex forecast for the 2019–24 period. We understand that this opex level will be close to our forecast for 2017–18 in our final decision (after adjustment for inflation and non-recurrent costs).

As part of Ausgrid's transformation program, it has been incurring substantial upfront redundancy costs to reduce its labour force to a more efficient level. This partially explains the increase in its annual opex since 2012–13. Table 4 shows Ausgrid's labour redundancy costs over the 2014–19 period that it provided to the AER.

49 Ausgrid, *Annual Report 2015/16*, October 2016, p.8. Ausgrid, *Expenditure Forecasting Methodology 2019–24*, 30 June 2017, p. 19-20

Table 4 Ausgrid's labour redundancy costs

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Redundancy costs	106.4	90.1	34.3	N/A	N/A
Proportion of opex	16.5%	15.6%	6.7%		

Source: Ausgrid response to AER information request

4.3.1.2 Endeavour Energy

Table 5 shows the differences between the opex Endeavour Energy has incurred since 2014–15 and the forecasts in our final decision.

Table 5 Differences between Endeavour Energy actual opex and final decision

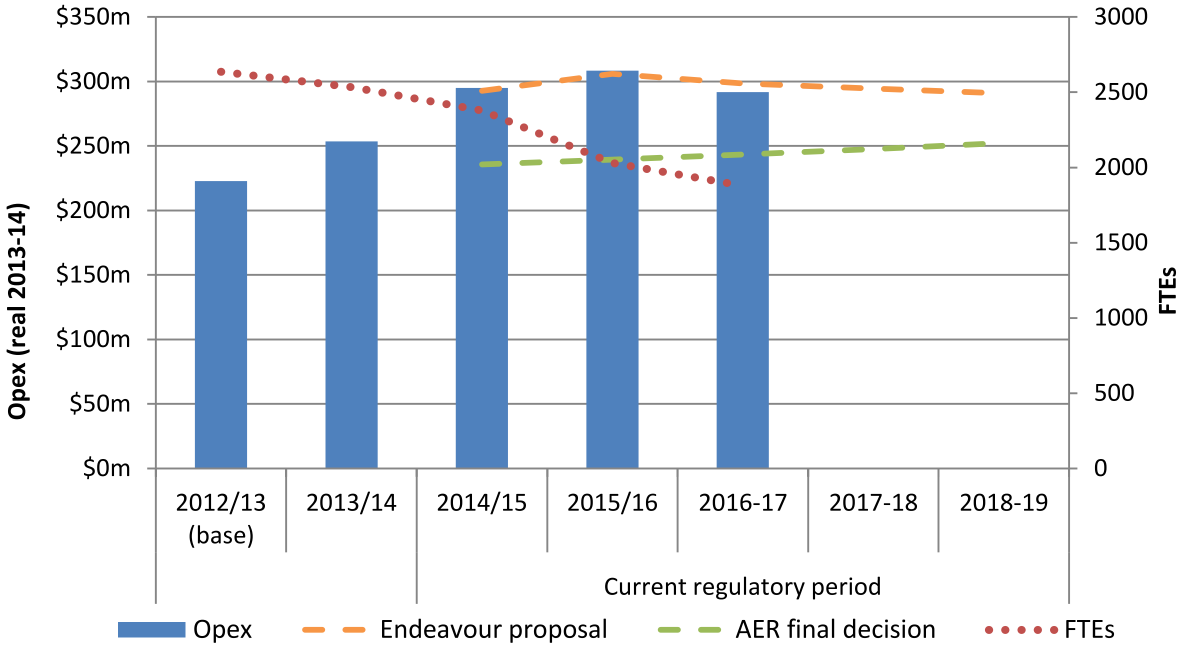
$m, 2013-14	2014–15	2015–16	2016–17	2017–18	2018–19
Endeavour Energy revised proposal	289.5	302.5	295.1	291.1	287.3
Actual opex	288.1	305.6	294.7	N/A	N/A
AER final decision	235.8	239.5	243.3	247.5	252.3
Difference	52.3	66.1	51.4	N/A	N/A

Source: AER final decision; Annual RIN.

Note: Numbers may not add up due to rounding.

Unlike for the other distributors, we used Endeavour Energy’s actual opex in 2012–13 as the starting point for our opex forecast rather than a benchmark base opex level. Figure 3 shows that Endeavour Energy’s annual opex increased significantly since its 2012–13 base year, and is 31 per cent higher in 2016-17. Endeavour Energy’s actual opex has exceeded our forecast in each year of the 2014–19 period to date. Endeavour Energy reduced its permanent FTEs by 29 per cent over this period.

Figure 3 Endeavour Energy actual opex, AER forecast opex, and Endeavour Energy proposed opex for 2014–19, including movements in FTEs



Source: AER final decision; Annual RIN; Endeavour response to AER information request; Endeavour annual report

Note: Actual opex excludes provisions in provisions. Opex prior to 2014–15 has also been normalised by excluding metering and ancillary costs prior to 2014–15.

Given we found that Endeavour Energy's actual opex in 2012–13 was not materially inefficient, we applied the EBSS for the 2014–19 regulatory control period. This means that any cost savings or cost over-runs will be shared between Endeavour Energy and consumers. While Endeavour Energy's opex increased since 2012–13 and is materially above our forecast, it will bear no more than 30 per cent of these additional costs by operation of the EBSS. We consider this further in the transition costs section below.

Endeavour Energy is undertaking a transformation program to reduce costs. While its costs are currently above our forecast, Endeavour Energy's preliminary opex forecast for the 2019–24 regulatory control period adopts an opex cost base that is equal to our forecast for 2018–19.[50] Endeavour Energy states that:

> We consider this is a reasonable starting point as it relies on an opex amount that sits within the AER's previously determined efficiency frontier. Our main concern for the current period was the lack of a transition to a substantively lower allowance amount rather than the amount itself. We have worked hard over the current period to reduce our opex to reach the efficient frontier and we will be in a position to meet the efficient opex allowance in the future.[51]

50 Endeavour Energy, *Directions paper for consultation 1 July 2019 – 30 June 2024*, August 2017, p. 33.

51 Ibid.

As part of Endeavour Energy's transformation program, it has been incurring upfront redundancy costs to reduce its labour force to a more efficient level. Table 6 shows Endeavour's labour redundancy costs over the 2014–19 period that it provided to the AER.

Table 6 Endeavour Energy's labour redundancy costs

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Redundancy costs	13.1	29.1	N/A	N/A	N/A
Proportion of opex	4.5%	9.5%			

Source: Endeavour response to AER information requests

4.3.1.3 ActewAGL

Table 7 shows the differences between the opex ActewAGL incurred since 2014–15 and the forecasts in our final decision.

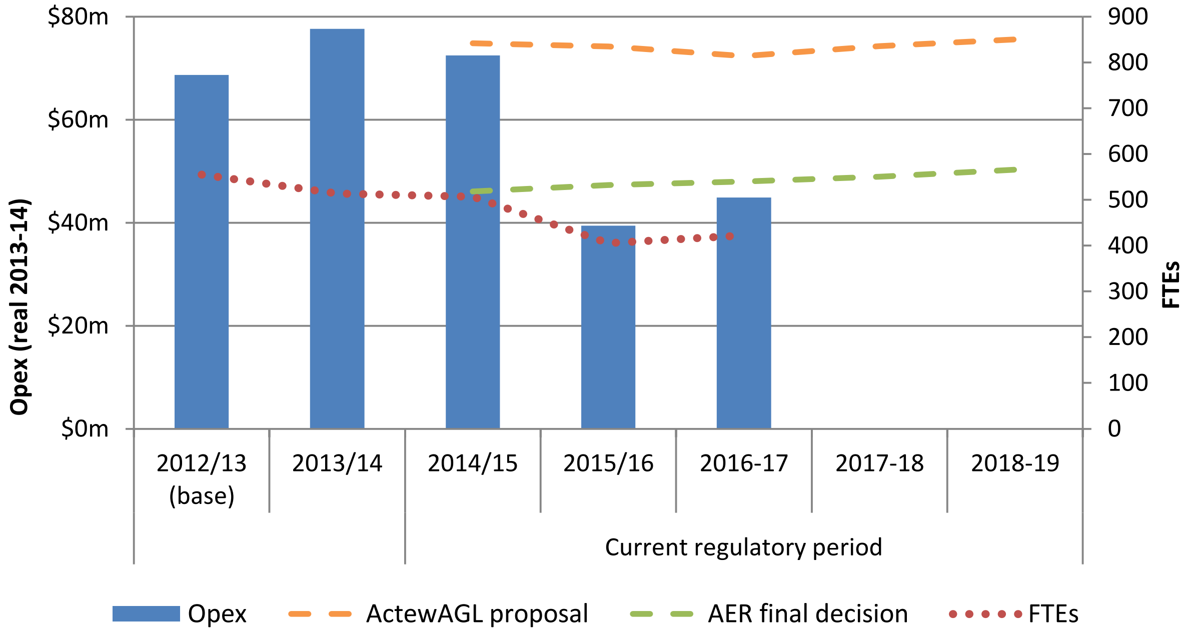
Table 7 Differences between ActewAGL actual opex and final decision

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
ActewAGL revised proposal	74.8	74.2	72.3	74.3	75.6
Actual opex	73.0	39.8	45.3	N/A	N/A
AER final decision	46.1	47.3	48.0	48.9	50.3
Difference	26.9	-7.5	-2.7		

Source: AER final decision; Annual RIN; ActewAGL response to AER information request

Figure 4 shows that ActewAGL's opex has decreased by 35 per cent between 2012–13 and 2016–17. ActewAGL's actual opex is below our final decision forecasts in both 2015–16 and 2016–17. ActewAGL reduced its permanent FTEs by 25 per cent over this period.

Figure 4 ActewAGL actual opex, AER forecast opex, and ActewAGL proposed opex for 2014–19, including movements in FTEs



Source: AER final decision; Annual RIN; Category Analysis RIN; ActewAGL response to AER information request

Note: Actual opex has been normalised by excluding metering and ancillary costs and effect of the material differences in capitalisation policy prior to 2014–15.

ActewAGL has submitted:

> … actual opex in the current regulatory period is significantly lower than ActewAGL Distribution's proposed opex for the period, and has been driven by the uncertainty as to the outcome of the prolonged appeal process in respect of the AER's opex decision in its Final Decision, ActewAGL distribution determination 2015–16 to 2018–19 (2015 determination), rather than an efficient and prudent program for maintenance of its distribution network. ActewAGL Distribution considers that the AER's opex allowance is not consistent with the level of opex required for the sustainable maintenance of a safe and reliable supply of electricity in the ACT.[52]

While ActewAGL managed to outperform our opex forecast in both 2015–16 and 2016–17, it has not reported to us any issues relating to material adverse effects on the safety and/or reliability of its network as a result of its opex incurred to date.

4.3.2 Actual capex incurred in the 2014–19 regulatory control period

As noted in section 4.1.2, in remaking our opex decision we must take into account the interrelationships between opex and our other constituent decisions, including capex.[53] Capex is particularly relevant to our opex assessment as a network business' capitalisation policies, cost allocations and opex/capex trade–off decisions have a material impact on its

52 ActewAGL, *Expenditure Forecasting Methodology 2019–2024*, June 2017, p.12.

53 NER, cl. 6.5.6(e)(7); NEL, s. 16(1)(c).

reported expenditure that we may use for forecasting purposes. Where the distributors have overspent against our opex forecast and seek to recover their actual costs in transitioning to an efficient level of opex, a question arises as to how any actual underspends on capex should be treated given the relevant interrelationships.

To date, the distributors, with the exception of ActewAGL, have significantly underspent against our capex forecasts during the 2014–19 regulatory control period. This is set out in tables 9 – 11 below.

Under the building block model framework, a distributor will normally receive two revenue benefits from spending less capex than forecast in the 2014–19 regulatory control period:

- cost savings within the 2014–19 regulatory control period due to lesser cost of capital than provided for within the AER's annual revenue allowance; and
- a financial incentive reward in the subsequent 2019–24 regulatory control period arising from the capital expenditure sharing scheme (CESS) .

The total benefit of these will be approximately 30 per cent of the net present value of the capex underspend.

Table 8 Difference between AER final decision capex and Ausgrid actual capex

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
AER final decision	599.0	643.2	652.0	593.5	518.3
Actual capex	536.7	296.7	N/A	N/A	N/A
Difference	62.3	346.5			

Source: AER final decision; Annual RIN.

Note: Excludes capital contribution and disposals.

Table 9 Difference between AER final decision capex and Endeavour Energy actual capex

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
AER final decision	413.5	334.9	283.0	274.8	262.6
Actual capex	354.5	207.2	N/A	N/A	N/A
Difference	59.0	127.7			

Source: AER final decision; Annual RIN.

Note: Excludes capital contribution and disposals.

Table 10 Differences between AER final decision capex and ActewAGL actual capex

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
AER final decision	72.6	60.2	64.3	56.0	54.9
Actual capex	71.1	58.3	N/A	N/A	N/A
Difference	1.5	1.9			

Source: AER final decision; Annual RIN.

Note: Excludes capital contribution and disposals.

Questions:

1. For distributors whose revealed costs to date or revised targets for 2018–19 are close to our final decision 2018–19 opex forecasts, do you consider it reasonable for us to rely on these revealed costs or revised targets to forecast opex? If we are not to rely on the distributors' revealed costs or revised targets, what other tools or approaches should we use to forecast opex?

2. ActewAGL's revealed costs in the regulatory years 2015–16 and 2016–17 are less than the forecasts we determined in our final decision. There is no information or evidence before us that suggests ActewAGL's network has been adversely affected during the 2014–19 regulatory control period, including from a safety and reliability perspective. Based on this observation, does this suggest that ActewAGL's revealed costs in 2015–16 and 2016–17 represent a prudent and efficient level of opex? If we cannot rely on revealed costs in this case, what other tools or approaches should we use to forecast ActewAGL's opex?

4.4 Transition path allowance

In remaking our opex decision, a residual question before us is whether we should provide the distributors with a transition path allowance.

If we do provide the distributors with a transition path allowance, the question becomes how much, and the proportions in which these costs should be borne between the distributors and consumers.

Generally, a transition path allowance can be characterised as constituting:

- transactional transition costs, which typically include the costs of making redundancy payments to reduce labour levels and terminating contracts early; and
- the inefficient costs that a distributor may continue to incur in the short term as it moves towards a lower level of opex, given it may not be able to transition immediately from its existing to that lower level of opex at the beginning of a regulatory control period.

In response to us reducing their forecast opex allowances in our final decisions, Ausgrid, Essential Energy and ActewAGL submitted that we should provide them with an allowance to cover the costs they would incur in transitioning from their existing level of opex to a lower (efficient) level of opex.

The issue of a transition path allowance did not specifically arise for Endeavour Energy because we relied on its revealed costs to set their base opex for forecasting efficient opex for the 2014–19 regulatory control period. However, as noted above, Endeavour Energy has nevertheless submitted that its main concern is whether it can be provided with a transition path allowance to recover the difference between its actual opex and our opex forecast in the 2014–19 regulatory control period.

4.4.1 Previous positions

4.4.1.1 AER position

Our position in the NSW and ACT 2014–19 final decisions, as well as before the Tribunal and the Court, was that a transition path allowance is not efficient and prudent and cannot be provided as part of an opex allowance that reasonably reflects the opex criteria.[54]

In the final decision for Ausgrid, we stated:[55]

> As outlined in the [Expenditure Forecast Assessment] Guideline, if the prudent and efficient opex allowance to achieve the opex objectives is lower than a service provider's current opex, we would expect a prudent operator would take the necessary action to improve its efficiency and prudency. We would expect a service provider (including its shareholders) to bear the cost of any inefficiency or imprudent actions. To do otherwise, would mean electricity network consumers would fund some costs of a service provider's inefficiency or imprudent actions.
>
> Accordingly, if our opex forecast is lower than a service provider's current opex we would generally not consider it open to us to provide a transition path to the efficient allowance. This approach is reflected in the NER, which provides that we must be satisfied that the opex forecast reasonably reflects the efficient costs of a prudent operator given reasonable expectations of the demand forecast and cost inputs to achieve the expenditure objectives.

4.4.1.2 Distributors' position

The distributors previously contended that we should provide a transition path allowance.[56]

For example, Networks NSW – on behalf of Ausgrid, Endeavour Energy and Essential Energy – submitted to the Tribunal:[57]

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54 AER, *Final Decision, Ausgrid distribution determination 2015−16 to 2018−19, Attachment 7 – Operating expenditure*, April 2015, pp. 7-40–7-46.

55 AER, *Final Decision, Ausgrid distribution determination 2015−16 to 2018−19, Attachment 7 – Operating expenditure*, April 2015, pp. 7-21, 7-22.

56 See, e.g., Ergon Energy, *Regulatory Proposal 2015-20 (Revised), Appendix E: The need for a 'transition path' for operating and capital expenditure*, July 2015, p. 162. [CHANGE] Similar submissions have previously also been made by Professionals Australia and the McKell Institute: Professionals Australia, *Response to the Australian Energy Regulator's draft regulatory determinations to NSW and ACT transmission and distribution businesses 2014 – 2019*, 12 February 2015, pp. 20 and 21; McKell Institute, Submission to the AER: Response to Ausgrid Draft Determination, February 2015, pp. 16 and 17.

57 Australian Competition Tribunal, *Submissions of Ausgrid, Endeavour Energy and Essential Energy – NON-CONFIDENTIAL (redacted) ACT 4, 6 & 7 of 2015*, 20 August 2015, [597] and [598].

Networks NSW not only have to make immediate and deep cuts to opex, but are required to make up the difference in respect of their 'overspend' in 2014–15.

This extraordinary result is not required by the NEL or the Rules and is not sound regulatory practice. Even if all of Networks NSW's other submissions on opex are rejected, the AER ought to have provided a transition period or 'glide path' to enable each of the Networks NSW businesses to transition to what the AER considered was an efficient level of opex.

There were two main reasons for the distributors' position. Firstly, not providing a transition allowance may put at risk the safe and reliable operation of the network. Secondly, compliance with a distributor's EBA is a regulatory obligation or requirement and therefore justifies the recovery of all costs associated with an EBA.

4.4.1.3 Consumers' position

The position of consumers was generally the same as ours.

For example, PIAC previously submitted:[58]

> PIAC recommends that there should be no transition period towards more efficient opex spend by the NSW networks. The Draft Determinations already allow for a level of inefficiency, including a 10% downward adjustment from the 'efficiency frontier'. Restructures should be funded out of profits as would be the case in a competitive market and consumers should not wear the costs of reforms on the path to efficiency.

Similarly, EnergyAustralia, Origin Energy and the Energy Retailers Association of Australia (the ERAA) previously submitted:[59]

> EnergyAustralia does not agree that it is appropriate for our customers to continue to bear the cost of previous decisions – such as entering into certain enterprise agreements that determine employment levels and greatly influence labour productivity – that have led to what are now recognised as inefficient practices and excessive expenditure.
>
> Origin considers that the recovery of any costs that do not meet the opex criteria set out in the NER must be borne by the DNSPs, not consumers. To the extent that the DNSPs have enjoyed the benefits of excessive opex funding, the onus of responsibility to restore network prices to efficient levels must reside with the businesses, not the consumers.
>
> These adjustments result in a balanced decision that reflects both the degree of existing inefficiencies in the distributor's business operations while at the same time providing an allowance that a prudent operator would require to achieve the operating expenditure objectives. [The ERAA] strongly oppose the view that consumers should bear the transition costs for the distributors to reach an efficient level.

4.4.2 Direction from the Tribunal and the Federal Court

Both the Tribunal and the Court did not substantively address the issue of a transition path allowance on the basis of their findings on how we determined our substitute estimates.

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58 PIAC, *A missed opportunity? Submission to the Australian Energy Regulator's Draft Determination for Ausgrid, Endeavour Energy and Essential Energy*, 13 February 2015, p. 32.

59 EnergyAustralia, *Submission to Australian Energy Regulator – Determination of allowable revenue for NSW electricity distribution networks*, 13 February 2015, pp. 5 and 6. Origin Energy, *Re: Submission to AER Draft Determination for NSW Electricity Distributors*, 13 February 2015, pp. 7 and 8. Energy Retailers Association of Australia, *RE: NSW electricity distribution draft determinations 2014-2015 to 2018-19, 13 February 2015*, p. 2.

The Tribunal stated:[60]

> Due to the Tribunal's findings on opex, the Tribunal does not, in the circumstances, need to determine whether these contentions by Networks NSW, ActewAGL and Ergon are correct. When the AER revisits and redetermines the opex allowance, it will have to consider the costs involved in transitioning. It will do so at a time, and in relation to revenue streams, which will require it to make a fresh decision. The Tribunal is anxious not to inhibit the AER at this point in exercising its discretion in that regard.

Relevant to the issue of the distributors transitioning to an efficient level of opex, the Tribunal also stated:[61]

> … having regard to the regulatory prescriptions, the Tribunal does not accept that it may, by the use of the EI model, simply select the measurement of efficiency which it did in this respect without regard to the obligations under the EBAs as they presently exist. Over time, and probably during the new current regulatory period, any such inefficiencies as the AER considers to exist may progressively be reduced by the reduction in employee numbers to what the AER considers to be the efficient number, and any allowances under the EBAs (as they expire) which the AER considers to be inefficient may also by the same elapse of time be reduced to an efficient level.

4.4.3 Who bears the cost?

The ultimate question here is whether the costs that constitute a transition path allowance should be borne by the distributor or consumers, and if so, the extent to which this should be the case and in what circumstances. As noted above, the Tribunal noted that this issue is one which we will need to consider in remaking our opex decisions.

Outlined below are a number of the principles and statements that the Tribunal and the Court made that we consider are relevant to the issue of transition path allowance.

In considering this material, one outcome that may meet the opex criteria, the RPP and contributes to achieving the NEO is that both the distributors and consumers share the burden of these transition costs.

In identifying the outcome that best achieves the NEO, it is also pertinent to consider the way in which the regulatory framework under Chapter 6 of the NER operates. The framework is ex–ante and incentive–based. It is not a cost–recovery framework. Further, the framework distinguishes between those operations and costs which are endogenous to, or within the control of, the regulated business from those which are not and exogenous. This recognises that the risks associated with matters that are endogenous to a regulated business are best managed and borne by the regulated business, not consumers.

Conversely, matters that are exogenous, of which a regulated business has no control over, are appropriately borne by consumers. The cost pass–through mechanism, which lowers the risk faced by a distributor in the event of an unexpected event outside its control and passes it on to the consumer, is an example of how the regulatory framework deals with exogenous circumstances. Another example is how the AEMC expressly considered that in undertaking

60 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [494].

61 Ibid, [436].

benchmarking, the AER would generally take into account circumstances exogenous (not endogenous) to a service provider.[62]

Importantly, whether a decision is characterised as endogenous or exogenous does not itself determine whether a transition path allowance should be provided to allow a distributor to recover a particular kind of cost. It is simply one relevant consideration that must be taken into account in light of all the relevant facts available, including any countervailing circumstances that might mitigate such a conclusion.

For example, the Tribunal considered that EBAs should not be viewed as an endogenous managerial choice "in circumstances where the AER has quite radically shifted from an itemised bottom–up approach to assessing opex to benchmarking total opex per se".[63]

Further, the Court stated:[64]

> The Tribunal went on to consider the AER's conclusion that the EBAs were endogenous and, therefore, to be ignored. The Tribunal rejected an approach that simply characterised an obligation as endogenous and to be ignored or as exogenous and to be considered, and said that a closer analysis was required. We think this was what the Tribunal was saying when it referred to the pressure placed on the NSW service providers by the Ministerial licence conditions and their response to it and, that that having happened, to the Fair Work Act being an exogenous factor. Leaving aside precisely what is meant by an endogenous matter and exogenous matter, we do not think that the Tribunal erred in finding error in this approach of the AER. The distinction might be a useful one, but it should not be used in a way which precludes an examination of all the facts and circumstances.

Similarly, in *Application by SA Power Networks* [2016] ACompT 11, in considering the issue of labour cost escalators for SAPN, the Tribunal again stated that whilst an EBA is not a regulatory obligation or requirement, the costs associated with an EBA must be taken into account and cannot be ignored. Specifically:[65]

> It is after this discussion that paragraph [436] of the Tribunal's reasons emerge on which SAPN relies. When the Tribunal refers in that paragraph to "the policy of the legislative arm of government that, to the extent that the EBA's are (if they are) an inefficient imposition on the DNSPs, nevertheless they are a cost to be borne by the consumers of electricity", it is referring to the fact that an EA is binding in the sense in which they had previously used it. That is, the Tribunal is suggesting it could not have been the policy intent of the legislature to permit the AER (relevantly when applying the EI model) to ignore the binding nature of an EA and to treat it wholly as an endogenous factor which could be ignored by the AER. It is not suggesting that the cost impacts of an EA should, as matter of policy expressed by the legislature, be disregarded entirely or conversely, automatically adopted.

Underlying our current position is the proposition that the costs underlying a transition path allowance are costs over which a distributor either now, or at some previous point in time, had control over. A decision to enter a contract with particular terms or a labour arrangement of a particular kind is generally an endogenous decision for the distributor to make. The facts

62 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 113.

63 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1, [434].

64 *Australian Energy Regulator v Australian Competition Tribunal (No 2)* [2017] FCAFC 79, [370].

65 *Application by SA Power Networks* [2016] ACompT 11, [542].

before us at the time of the draft and final decisions did not support a conclusion that not providing a transition path allowance would deprive a distributor of recovering at least its efficient costs or would put at risk the operation of the network and give rise to safety and reliability concerns.

However, as we noted above, given the principles and the remarks made by the Tribunal and the Court, we will need to re–consider our approach to assessing any transition costs, in light of all the relevant facts and circumstances.

4.4.4 Available transition cost information

Table 11 shows each distributor's actual opex in the 2014–19 regulatory control period to date less the AER's forecasts (as discussed in section 4.3.1). These amounts reflect the additional costs the distributors have incurred in the short–term as they move towards a lower level of opex towards the end of the 2014–19 regulatory control period. These would be characterised as the upper ceiling on potential transition costs.

Table 11 Differences between distributors' actual opex and AER forecast

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Ausgrid	255.1	181.5	108.7	N/A	N/A	545.3
Endeavour Energy	52.3	66.1	51.4	N/A	N/A	163.3
ActewAGL	26.9	-7.5	-2.7	N/A	N/A	15.6

Source: AER final decision; Annual RIN.

As noted above, Endeavour Energy is currently subject to the EBSS. If the AER's final decision opex forecast applied to Endeavour Energy over the 2014–19 period, then Endeavour Energy will bear no more than 30 per cent of the costs shown in Table 11.

All the distributors have incurred labour redundancy costs as part of their transition to efficient levels of opex over the 2014–19 period. Ausgrid and Endeavour Energy's labour redundancy costs are shown in Table 12 (as discussed in section 4.3.1). These costs may be relevant when considering the issue and quantum of transition costs.

Table 12 Distributor's redundancy costs in 2014–19

$m, 2013–14	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Ausgrid	106.4	90.1	34.3	N/A	N/A	230.8
Endeavour Energy	13.1	29.1	N/A	N/A	N/A	42.2

Source: Response to AER information requests.

Questions:

3. In the context of the incentive regime established in Chapter 6 of the NER, and in the circumstances of transitioning from a higher level of opex to a materially lower level of opex (specifically transactional transition costs and the inefficient costs over and above the forecast), should:

(a) consumers solely bear those costs (that is, a distributor's forecast opex should include an amount for a transition path allowance); or

(b) distributors solely bear those costs (that is, a distributor's forecast opex should not include an amount for a transition path allowance); or

(c) those costs be allocated or shared between consumers and distributors (that is, a distributor's forecast opex should include a partial amount for a transition path allowance)?

4. How do you justify your answer to question 3 having regard to the opex criteria, the RPP and the NEO and in particular, the long–term interests of consumers?

5. If you consider the costs that constitute a transition path allowance should be shared between consumers and distributors (i.e. that referred to in question 3(c)), how should these costs be allocated between the two? For example, should consumers fund the short-term transactional transition costs of distributors transitioning to an efficient level of opex (i.e. redundancy costs)?

6. Ausgrid, Endeavour Energy and ActewAGL (in 2014–15 only) have underspent against the capex forecasts we determined for them. Given we are required to have regard to the interrelationships between opex and capex, does this affect your answers to questions 3, 4 and 5, and if so, how?

7. An EBSS applies to Endeavour Energy, which means it only bears around 30 per cent of the costs it is considers constitutes a transition path allowance. Does this affect your answers to questions 3, 4 and 5, and if so, how?