energy networks association

20 April 2012

Mr Philip Weickhardt
Chair – Electricity Network Regulation Inquiry
Productivity Commission
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Canberra ACT 2600

via email: electricity@pc.gov.au

Dear Philip

Response to Productivity Commission Electricity Network Regulation Issues Paper

Thank you for the opportunity to make a submission in response to the Commission's Electricity Network Regulation Issues Paper published on 23 February 2012.

The ENA is the principal body representing energy network businesses. Its 23 members supply electricity to more than 8 million customers and gas to more than 3 million customers.

The ENA welcomes the Commission's inquiry into the role that benchmarking can play in contributing to the efficiency of electricity networks and this forms the focus of the attached submission.

An important context for the inquiry is that electricity prices have been rising in recent years. A significant contribution to this increase has been the prices charged by regulated distribution and, to a lesser extent, transmission network businesses. It is natural to ask whether those increases have been efficient or whether there is an issue with the regulatory framework that sets those charges and/or the way in which the regulator has in fact done so. These matters are being reviewed by the Australian Energy Market Commission (AEMC).

Within this context, the Productivity Commission can make a significant contribution by providing guidance on the practical role that benchmarking can play in improving the efficiency of the industry. To this end, the ENA submits that:

- benchmarking can be an effective component of the revenue setting process provided that it is carried out both robustly and consistently with the incentive-based framework set out in the National Electricity Rules;
- the benchmarking approach(es) used in specific situations will depend on a range of factors including the availability of data and the complexity of the adjustments required to make suitable like-for-like comparisons; and
- in this regard, there are difficulties which make using a purely statistical benchmarking approach unsuitable for setting revenues at high levels of data aggregation. For higher aggregation levels, benchmarking results should be used as an input into expert engineering analysis regarding the appropriateness of expenditure forecasts or as a means of identifying anomalies in an expenditure proposal that require closer examination.

The ENA has not addressed the issue of the effectiveness of the current regulatory arrangements for interconnection. It understands that this issue will be addressed by a submission by Grid Australia on behalf of the National Electricity Market (NEM) transmission network businesses.

If you have any questions please contact Jim Bain on or alternatively we would be pleased to provide the Commission with a comprehensive briefing on the ENA submission at its earliest convenience.

Yours sincerely

Malcolm Roberts
Chief Executive

Productivity Commission
Electricity Network Regulation

ENA Submission

April 2012

Table of contents

Executive summary

1. The Energy Networks Association (ENA) welcomes the Productivity Commission's inquiry into the role that benchmarking can play in contributing to the efficiency of the electricity networks.

Context

2. An important context for the inquiry is that electricity prices have been rising in recent years. A significant contribution to this increase has been the prices charged by regulated distribution and, to a lesser extent, transmission network businesses. It is natural to ask whether those increases have been efficient or whether there is a problem with the National Electricity Rules (the Rules) used to set those charges and/or the way in which they have been applied by the Australian Energy Regulator (the AER).

3. The ENA considers that:

   - the network price rises have been efficient;
   - while there are some areas where the Rules could be improved, they do not prevent the AER from using benchmarking as part of setting network charges at efficient levels; and
   - the way in which the AER applies the Rules has contributed to the perception that network charges are inefficient and that changes to the Rules are therefore required.

   These matters are currently being reviewed by the Australian Energy Market Commission (AEMC).

The role of benchmarking

4. The ENA submits that the area where the Productivity Commission can make the greatest contribution is to provide guidance on the practical role that benchmarking can play in improving the efficiency of the industry. The use of benchmarking broadly defined is already pervasive (and unavoidable) in the way that the AER assesses almost all network expenditure forecasts. The key question is how the AER's use of benchmarking can be enhanced in order to improve the accuracy of those assessments.

5. Criteria for assessing whether a benchmarking approach is appropriate include robustness, transparency, the promotion of efficiency, the reasonableness of the data requirements, adaptability and the cost and time for acquiring and processing the data. An important further criterion is that the benchmarking approach must be consistent with the broader incentive-based regulatory framework contained in the Rules. A fundamental design aspect of that framework is that it provides the network businesses with certainty that they will earn a reasonable return on their past

investments while ensuring that their future expenditure proposals are reasonably efficient.

6. A key way to characterise benchmarking is either as:

- "pure statistical" benchmarking where the researcher attempts to make all adjustments for comparability within the analysis itself (as opposed to making adjustments for information engineering experts regard as relevant but which was not capable of being captured in the statistical analysis); or
- "expert" benchmarking where statistical benchmarking is used but takes place within, or the results of which are guided by, expert engineering assessments of the business's expenditure proposals.

7. The ENA supports the appropriate use of both of these forms of benchmarking. Which form is given more weight in particular circumstances will depend on a range of factors including the availability of suitable data and the complexity of the adjustments required to make like-for-like comparisons.

8. Importantly, the results of benchmarking should be used as an input to expert analysis by network engineers wherever possible. For example, if benchmarking suggests that a certain level of expenditure is efficient but network engineers agree that a higher or lower level is required due to factors not captured in the benchmarking, then these opinions should be accorded greater weight. This describes what already happens as a matter of course in most expert analysis commissioned by the AER (reports provided by Nuttall Consulting are used as examples).

9. The ENA considers that it is not yet possible to set efficient costs using pure statistical benchmarking at high levels of aggregation without regard to expert interpretation. Doing so would impose material regulatory risk on the businesses and deter much needed investment in the regulated network sector. This is because:

- there are too many causal factors (independent variables) that need to be accounted for — the dangers of doing so are highlighted by reference to two recent reports by Bruce Mountain; and
- at that level of aggregation, doing so prevents businesses from having a reasonable basis to defend their detailed expenditure proposals.

10. In the ENA's view, pure statistical analysis is most likely to be useful:

- as a means of identifying anomalies in an expenditure proposal that require closer more detailed examination; or
- when applied at low levels of expenditure aggregation[1].

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1 But not so low that the cost and time involved in collecting and analysing the data outweigh the benefits of a timely regulatory assessment.

1. Introduction

11. This submission is in response to the Productivity Commission's Inquiry into Electricity Network Regulation specifically as it relates to the use of benchmarking to inform regulatory decisions. The ENA understands that the matters raised by the Productivity Commission in relation to whether the regulatory regime is delivering economically efficient levels of interconnection are being addressed by a submission from Grid Australia. Grid Australia represents the National Electricity Market (NEM) transmission network businesses.

12. The structure of the remainder of this submission is as follows:

- Section 2 examines the wider context of the Inquiry;
- Section 3 provides a high level description of, and the rationale underpinning, the incentive-based revenue regulation framework applicable to electricity network businesses contained in the National Electricity Rules (the Rules);
- Section 4 categorises different types of benchmarking used under the Rules and the ENA's view on their relative strengths and weaknesses;
- Section 5 outlines the practical issues associated with making like-for-like comparisons across electricity network businesses;
- Section 6 discusses the ENA's criteria for good benchmarking;
- Section 7 illustrates benchmarking undertaken by the Australian Energy Regulator (AER) and others that illustrates the themes developed in the previous sections;
- Appendices A and B are reports by NERA Economic Consulting (NERA) prepared for the ENA as part of its submission to the Australian Energy Market Commission's (AEMC's) Directions Paper on the economic regulation of network businesses Rule change proposal[2]:
    - o the report at Appendix A provides an understanding of the key drivers of recent network price increases; and
    - o the report at Appendix B critiques two recent reports by Bruce Mountain regarding those price rises and the productivity of the businesses; and
- Appendix C sets out a detailed response to each of the questions in the Productivity Commission's Issues Paper.

[2] See http://www.aemc.gov.au/Electricity/Rule-changes/Open/economic-regulation-of-network-service-providers-.html.

2. Wider context of the inquiry

13. Electricity prices have risen materially in recent years. A significant contribution to this increase has been the prices charged by regulated distribution and, to a lesser extent, transmission network businesses. This provides an important background to the Productivity Commission's inquiry and an important context for thinking about the role of benchmarking as part of the current regulatory framework.

14. There are three competing narratives that could explain why network prices have increased:

    (i) *the increases are efficient* — efficient network costs, including financing costs and the need to replace ageing assets, have increased materially and the operation of regulation under the Rules has, as is appropriate, led to corresponding price increases;

    (ii) *the increases are inefficient because there are problems with the Rules* — businesses' expenditure proposals have been excessive, but flaws in the way that the Rules are written have prevented the AER effectively using benchmarking as part of setting revenues at efficient levels; and/or

    (iii) *the increases are inefficient because the AER has failed to apply the Rules properly* — businesses' expenditure proposals have been excessive and the AER, despite having all the necessary powers under the Rules, including making an appropriate use of benchmarking, has failed to substitute a more reasonable estimate.

15. The ENA contends that (i) provides the correct explanation. That is, the increases are efficient because the regulatory framework under the Rules accurately reflects a range of relevant changes including:

    - increases in the prevailing cost of capital due to the global financial crisis;
    - increases in the need to replace assets due to an increasingly significant proportion of asset stock reaching the end of its economic life;
    - changes to network planning standards; and
    - continuing increases in peak demand that outstrip growth in energy usage due, for example, to the increased penetration of air conditioning.

    This view is supported by the report at Appendix A that reviews the reasons underpinning recent network revenue determinations made by the AER.

16. By contrast, the AER argues that explanation (ii) is correct. The regulator has proposed changes to the Rules that is specifically justified on this basis. The AEMC is in the process of assessing the merits of this claim as well as a related proposal made by the Energy Users Association Rule Change Committee (EURCC). This is the appropriate mechanism for assessing those proposals and the ENA notes that any duplication of that process is likely to add to regulatory uncertainty.

17. The ENA notes that there are areas where the Rules appear able to be improved. In this regard, the AEMC's Directions Paper as part of its process for assessing the AER and EURCC Rule change proposals where it noted *inter alia* that:

- the current arrangements for setting the cost of capital for transmission networks may not cope adequately with changing market conditions as occurred in the Global Financial Crisis);
- there is scope for improving the incentive scheme for encouraging efficient capital expenditure during a regulatory control period; and
- there appear to be opportunities to improve the processes for lodging and consulting on regulatory proposals to improve participation by consumers and their representatives in the regulator's determinations.

18. Importantly, however, the Rules do not prevent the AER from using benchmarking as part of setting network revenues at efficient levels. Indeed, as demonstrated further below, the evidence is that the AER regularly uses benchmarking in making these assessments. The correct question is whether the type of benchmarking that it applies is the most appropriate.

19. It should not be presumed that any perceived underutilisation of benchmarking by the AER is symptomatic of a restriction in the Rules[3]. Indeed, the AEMC's adviser, Professor Yarrow, has questioned the basis for such claims by the AER: [4]

> *That there is a general problem of increasing electricity prices, and that increases in transmission and distribution costs are major contributors to price hikes, appears to be beyond contention. That, however, takes us very little along the way to answering the question of whether a material contribution to price increases is reasonably attributable to those aspects of the rules identified by the AER as warranting change.* ***The AER's submission asserts a relationship between the relevant subset of rules, but nowhere actually provides evidence or convincing reasoning in support of the assertion.*** (emphasis added)

20. Regarding narrative (iii), there are issues with the way in which the AER applies the Rules that have contributed to the *perception* that network charges are inefficient and that changes to the Rules are therefore required. For example, the Australian Competition Tribunal has found in favour of the network businesses on no less than ten occasions in relation to the AER's approach to setting the regulated cost of debt. The AER has cited this in support of its claim that the Rules (including the limited merits review framework for reviewing AER determinations) must therefore be biased in favour of the businesses. However, as the Tribunal makes clear, the correct

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3 The ENA noes that the AEMC has previously considered the potential for the AER to use Total Factor Productivity (TFP) benchmarking under the Rules as currently constituted (AEMC, Final Report, Review into the use of total factor productivity for the determination of prices and revenues). It concluded that the approach is permitted but not heavily used and that a better, more consistent data-set would need to be established before this form of benchmarking could be used in future determinations.

4 Yarrow, Preliminary Views for the AEMC, p. 9 (http://www.aemc.gov.au/Media/docs/Professor-George-Yarrow-c4794217-ac6d-4927-a9fb-1a55d09b38cd-0.PDF)

explanation is the consistently inappropriate approach(es) used by the regulator to assessing the cost of debt. Indeed, the Tribunal has on a number of occasions recommended that the AER consult widely on this matter in order to develop a methodology to address the shortcomings in its approach. The ENA supports the Tribunal's recommendations noting that this is not a shortcoming of the Rules *per se* but rather the way in which the AER has chosen to apply the Rules.

21. In the ENA's view, the Productivity Commission's review would be most helpful to industry stakeholders, including the AER, if it provided guidance on how best to use benchmarking to assess the reasonableness of businesses' expenditure proposals under the Rules as they are currently constituted. In particular, this should address:

- the criteria that need to be met for the robust use of benchmarking in assessing the reasonableness of businesses' expenditure proposals;
- which type or types of benchmarking would be most likely to meet those criteria in different circumstances;
- the extent to which benchmarking of this type is already used by the AER and the extent to which particular methodologies are underutilised in specific circumstances; and
- the additional investment in data collection or other "ground work" that could usefully be undertaken in order to improve the robustness of benchmarking.

3. Incentive regulation and the Rules regulatory framework

3.1. Objective of regulation

22. A key objective of regulation of monopoly services is to promote the efficient investment in, and operation and use of, the regulated assets to the ultimate benefit of end users. This involves delivering the desired levels of service quality/reliability to consumers while incurring no more than the efficient costs necessary to do so.

23. A second key objective of regulation is to protect the property rights of regulated asset owners. These interests are explicitly recognised in a number of regulatory regimes. For example, the regulator of telecommunications in Australia is required to have regard to the legitimate business interests of the regulated firm. In other frameworks it is implicitly recognised as a means of delivering sustainable service quality/reliability. If investors cannot expect to have their property rights respected, this undermines their incentives to deliver the desired quality and reliability of service. This is particularly important in the case of capital intensive infrastructure businesses such as electricity and gas transport where the investments concern assets that can be in service for over 40 years.

24. Section 7 of the National Electricity Law (the NEL) sets out the National Electricity Objective (the NEO) which reflects both these key principles:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.*

25. The key principles are also reflected in the Revenue and Pricing Principles set out in section 7A of the NEL. Those include providing the regulated business with:

- effective incentives to promote efficient charges (sub-section 7A(3)); and
- a reasonable opportunity to recover at least the efficient costs of providing the regulated services (sub-section 7A(2)) plus a risk adjusted return on capital (sub-section 7A(5)),

as well as having regard to previous valuations of the regulated asset base when making revenue determinations (sub-section 7A(4)).

3.2. Lack of information and incentive regulation

26. If the level of efficient costs, and the processes for arriving at those costs, were known with certainty, then regulation of natural monopolies would be a relatively simple task. The regulator would be able to accurately estimate the cost of efficient service delivery and would compensate investors accordingly. The investors would know how to

achieve these efficient costs and would be able to do so. As a result, they would be able to earn a reasonable return on investments given the level of compensation allowed by the regulator.

27. In reality, efficient costs are not known *a priori* even by the owners of the business. That is, businesses do not necessarily know the least cost means of delivering the desired service quality. This must be discovered by the business through external research as well as through the adaptation of business practices suitable to their particular circumstances (including through experimentation). Moreover, this will not be static. The level of efficient costs and the best process for achieving those costs will depend on changing market circumstances, including changing input prices and changing technologies. Moreover, what is an efficient strategy today will depend on past decisions relating to network design and investments in past technologies.

28. The level of efficient costs and the process for achieving those costs will generally be different for each regulated business for reasons discussed in section 5 below.

29. Consequently, attempting to estimate an aggregate level of efficient costs divorced from the actual costs of a business will likely provide a very poor estimate the level of efficient costs for any given business. The regulator could, nonetheless, compensate investors on the basis of a very imprecise estimate of efficient costs. However, the effect of doing so would inevitably be to weaken the property rights of some investors whose efficient costs have been underestimated to create uncertainty even for investors whose efficient costs have not been underestimated in the past. Such an approach would undermine the stability and predictability of the regulatory regime, which in turn damages investment incentives.

30. The best way a regulator can arrive at an estimate of efficient costs is by giving the business an incentive to be efficient and observing the costs that result from that incentive. This means that a business must expect to be able to 'keep' some part of the benefits associated with achieving efficiency (and expect to pay a penalty for any reduction in efficiency). This expectation gives the business the incentive to *reveal* efficient costs to the regulator.

31. Assuming that the business knows how to achieve efficiency but that the regulator does not is sometimes described as an asymmetry problem. Under this characterisation the business must be given an incentive to do what it already knows will be efficient.

32. However, this is an overly simplistic description of the problem. In reality, the business does not automatically 'know' how to achieve efficient costs. Information about how to achieve efficient costs is neither simple nor costless to acquire. Absent an incentive, a business has no reason to invest in acquiring this information. Therefore, incentive regulation is not just required in order for a business to reveal efficient costs; it is also required in order for a business to first discover (i.e. invest time and resources in finding out) what the efficient costs and processes are.

3.3. How the Rules resolves these difficulties

33. Chapters 6 and 6A of the Rules are the result of careful deliberation by stakeholders and the Rule makers on the question of how to best create a holistic environment for the discovery and revelation of efficient costs by regulated businesses. There are, broadly, two essential ingredients in the way that the Rules are designed to achieve this:

- the provision of incentives to discover and reveal efficient costs; and
- the establishment of firm property rights for investors in regulated assets.

3.3.1. Incentives to discover and reveal efficient costs

34. Chapters 6 and 6A of the Rules establish a process by which a regulated business is rewarded to the extent that it can sustainably lower its expenditure. This is achieved by compensating businesses for forecast expenditure rather than actual expenditure. As discussed below, the framework also provides incentives for the business to propose soundly based and reasonable expenditure forecasts.

35. In the case of both operating and capital expenditure, the AER arrives at a forecast of efficient operating expenditure over the five years of the regulatory period. This forecast feeds into the building block revenue allowance (discussed below) and is not revisited over the next five years (except in exceptional circumstances). As a consequence, the level of compensation a business receives over those five years does not change in line with actual expenditure. This, in turn, creates an incentive for the business to lower expenditures.

36. In the case of capital expenditure, lower expenditure results in a lower value for the regulatory asset base (RAB) at the beginning of the next regulatory period and, as a consequence, lowers prices for customers. However, the regulated business is rewarded for the forecast level of capital expenditure – giving investors an incentive to lower the forecast expenditure where possible.

37. The AER and its consultants may be able to infer permanent efficiencies from such conduct, for example, by observing changes to replacement practice that lengthens asset lives and permanently reduces replacement capital expenditures. The AER can then use this information in its assessment of future capital expenditure plans. When it does so, the AER is effectively benchmarking a businesses' future business plans against its past business operations (noting that the business has had an incentive to carry out its past operations efficiently). However, past levels of capital expenditure will have less relevance for some elements of the future capital expenditure program, for example where certain large scale projects are required due to forecast increases in demand over the future period.

38. Similarly, in the case of operating expenditure, at the end of one five year regulatory period the AER is able to observe the actual expenditures of the business and factor these into its views on forecast expenditure in the next regulatory period. Put simply, by creating an incentive to discover efficiencies costs the regime rewards the revelation of lower costs. However, once revealed, the regulator is able to pass those

onto customers in lower future forecasts – albeit with a lag where the length of the lag is proportional to the incentive to discover/reveal efficiencies. Once more, this involves benchmarking a businesses' future business plans against its past business operations.

39. The operation of the Efficiency Benefit Sharing Scheme (EBSS[5]) strengthens the incentives for efficiency by ensuring that sustained cost reductions/increases achieved at the end of one regulatory period are nonetheless rewarded/penalised for five years extending into the next regulatory period. Absent an EBSS, there would be an incentive to not discover and reveal cost savings towards the end of the regulatory period because doing so would allow the regulator to immediately reflect these in lower allowances for the next regulatory period.[6]

40. The incentive mechanisms for operating expenditure are designed to leverage the level of expenditure that a business reveals as efficient. It is assumed that the AER's forecast for efficient expenditure in the next regulatory period will reflect the level of expenditure actually achieved by the regulated business in the previous regulatory period. This assumption reflects the fact that, given that there are material incentives for efficiency, the *a priori* assumption should be that businesses are continuously discovering and revealing available efficiencies.

41. Nonetheless, the Rules do not require the AER to make this assumption. If the evidence exists, then it is open to the AER to make a finding that existing levels of expenditure are not efficient and for the AER to use a different baseline for its forecasts of efficient expenditure.

42. If the AER finds that the regulated business is not operating in a manner that is consistent with how a prudent operator in the same circumstances would operate then it is open to the AER to reject a forecast for expenditure that is based on the regulated businesses' past expenditures/practices. In making such an assessment there is no restriction on the analysis that the AER can perform, including comparisons between the business in question and other businesses (benchmarking). Indeed, the AER commonly does precisely this – as discussed in section 3.3.2 below. Rule 6.5.6 (e) (4) requires the AER to have regard to:

> *benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period.*

43. However, the AER can only reach a conclusion that a regulated business' forecast operating expenditure is not efficient based on robust evidence. This is an integral feature of the Rules design because to allow the AER to reach such a conclusion on non-robust evidence would undermine the second limb of the incentive regime – being the provision of a stable and clearly defined set of property rights to investors.

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5 See 6.5.8 of the Rules

6 Similarly, a perverse incentive could exist to raise expenditure in the hope that this would lead the regulator to raise future forecasts to reflect (falsely revealed) higher costs. The EBSS penalises businesses for any such increase in costs into the next regulatory period, thereby offsetting any value that they could (hypothetically) achieve by falsely raising expenditure above efficient levels and using this fact to attempt to influence the regulator to set higher forecasts.

3.3.2. Stable and clearly defined property rights

44. In order for investors to have appropriate incentives to invest and operate efficiently it is vital that they understand the regime within which they operate and that they are able to predict how they will be rewarded for discovering and revealing efficiencies. Fundamental to this process is the clear specification of property rights to the assets being used to provide regulated services.

45. The Rules achieve this in the specification of the RAB and the operation of a building block approach to setting revenues for which the RAB is a critical input. The building block approach can be simply understood as a requirement that a business must be compensated for:

- a return on and return of (depreciation) in the pre-existing RAB;
- efficient expenditure on new capital assets (by adding these to the pre-existing RAB); and
- efficient expenditure on operating and maintenance of the existing assets.

46. The RAB is a financial value of assets that reflects the valuation given to those assets by jurisdictional regulators prior to the introduction of the Rules (and commonly prior to privatisation of the businesses) plus the net[7] value of investments made by those businesses since that date.

47. It is relevant to note that the creation of the initial RAB in Victoria and South Australia was driven by the need to assign a value to underlying assets prior to the introduction of independent price regulation and the privatisation of assets. If the owner of a regulated business could have the financial value of pre-existing assets altered by the regulator at a later date then investors would be less inclined to continue to invest in the business (or to buy the business in the first place) than it would be if the financial value of pre-existing assets was fixed.

48. The Rules achieve the goal of clear property rights by establishing a fixed value for the RAB and a fixed process for how this value is updated over time to reflect depreciation and new investment.

49. This is an important context for the Productivity Commission to bear in mind when considering the role of benchmarking under the Rules. Benchmarking should not (and, under the Rules, explicitly cannot be used as a means for *ex post* revaluation of the historical RAB. This means that the context for benchmarking will need to be an assessment of proposed future expenditures (not past expenditures already embodied in the RAB).

50. It is conceivable that an alternative regime may leave it within the power of the regulator to alter the value of the RAB either explicitly or implicitly. An explicit

[7] Net of the return of capital to those businesses in regulated revenues and/or any rewards/penalties that accrued as a result of under/overspending against forecast capital expenditure.

alteration of the RAB might involve the regulator declaring that some historical investment was imprudent potentially on the basis of some sort of *ex post* benchmarking assessment. The Australian Competition and Consumer Commission (the ACCC, the AER's precursor as transmission regulator) arguably had this power in the early days of economic regulation, but explicitly asked for these powers to be removed on the grounds that they damaged investment incentives rather than aided them.

> *In the draft SRP the ACCC concluded that a lock in approach provides greater certainty for investment compared to a revaluation approach. The ACCC recognised that the code provides the discretion to revalue assets in service before (existing assets) and after (new assets) 1 July 1999. The ACCC considered that it would be preferable to amend the code to formalise the lock in approach to asset valuation.[8].*

51. This statement from the ACCC, and the subsequent adoption of this proposal in the NEL and Rules, is a reflection of the need for investment certainty when dealing with highly capital intensive businesses with very long lived assets.

52. An implicit expropriation of the value of past investment is likely to be just as damaging to incentives and operation of the regime as an explicit expropriation. An implicit alteration in the value of the RAB might involve the regulator continuing to allow a formal return on and of the RAB, but undermining the ability of a business to truly achieve such a return by setting other allowances well below achievable levels.

53. Professor Yarrow has noted in his preliminary views to the AEMC that implicit expropriation is an ever-present risk to investors – especially in the context of rising costs giving rise to price shocks:

> *As discussed above, the working presumption in the relevant economics15 is that a regulator with unconstrained discretion to set price controls will be tempted to opportunism, and that the temptation will be particularly great in circumstances of rate-shock. That is, at bottom, there is an underinvestment problem associated with the regulation of private monopoly.*
>
> *On this basis, it would be irrational for capital markets to believe that regulatory decisions will always be 'impartial'; particularly in periods of sharply rising costs. Put another way, regulatory discretion comes with biases of its own.[9]*

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[8] ACCC, 2004, Statement of regulatory principles - background paper (8 December 2004), p. 39. Available at http://www.aer.gov.au/content/item.phtml?itemId=660012&nodeId=34e6efa6a0b7cef3988f1fb86c420f85&fn=Statement%20of%20regulatory%20principles%20-%20background%20paper%20%288%20December%202004%29.pdf.

[9] Yarrow , Preliminary Views for the AEMC, pp. 9-10. Available at http://www.aemc.gov.au/Media/docs/Professor-George-Yarrow-c4794217-ac6d-4927-a9fb-1a55d09b38cd-0.PDF)

54. A key mechanism by which the Rules attempt to protect against an implicit undermining of property rights is found in Rules 6.5.6 and 6.5.7 which set out the basis on which operating and capital expenditure allowances are to be established. These Rules require:

- the business to prepare a forecast of required expenditure that complies with the relevant information requirements set out by the AER;
- the AER to decide whether it is satisfied that the total expenditure forecast reasonably reflects:
  - o the efficient costs of achieving the operating/capital expenditure objectives;
  - o the costs that a prudent operator in the circumstances of the relevant network business would require to achieve the *operating/capital expenditure objectives*; and
  - o a realistic expectation of the demand forecasts and cost inputs required to achieve the *operating/capital expenditure objectives*.
- if the AER is satisfied that this is the case then it must accept the businesses forecast; and
- if the AER is not satisfied that this is the case then it must not accept the forecast and can substitute its own estimate. The AER must have regard to the factors set out in 6.5.6(e) and 6.5.7(e) in making these decisions, including, for example, substitution possibilities between operating and capital expenditure.

55. By requiring the businesses to provide an expenditure proposal that the AER must accept if it is reasonable, the Rules are designed to create a potentially significant penalty/risk for businesses proposing excessive expenditures in the first instance. This is because doing so creates an opportunity for the AER to reject the excessive proposals and instead adopting its own alternative expenditure forecasts.

56. Rules 6.5.6 and 6.5.7 also provide protection for the business against arbitrary decisions by the AER. These Rules must be interpreted in the context of the Revenue and Pricing Principles in section 7A of the NEL already referred to. Section 7A(2) of those principles provides that:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

57. The ENA notes that the AER argues that this aspect of the Rules promotes inflated expenditure forecasts. In the ENA's view it has a powerful effect in the other direction. Businesses have a strong incentive to propose reasonable expenditure in the first instance because businesses can avoid the uncertainty that comes when, after rejecting the businesses proposal as unreasonable, the AER can substitute its own forecast. In any event, these are issues before the AEMC.

58. As already described, Rules 6.5.6 and 6.5.7 do not prevent the AER from concluding that business forecasts are inefficient (including because existing business costs are inefficiently high relative to comparable benchmarks). The point is that the AER needs to provide robust evidence to support such a conclusion.

4. Categorising benchmarking techniques

59. Cost benchmarking can be defined as an attempt to glean information about the cost of an output (or the most efficient process for producing an output) in one circumstance using information on costs (processes) from other circumstances.

60. Defined in this way it is clear that the AER will need to use some form of benchmarking in order to assess the reasonableness/efficiency of a firm's expenditure forecast under the Rules. That is, it is simply not possible to assess an expenditure forecast from an individual business without having regard to information on how other businesses organise their activities and/or the costs incurred by those businesses.

61. There are a number of important dimensions to benchmarking. In the current context, the two most important are:

- "pure statistical" and "expert" benchmarking; and
- higher versus lower levels of data aggregation.

The remainder of this section discusses these and other relevant dimensions and how the effectiveness of benchmarking may vary with them.

62. At the end of the section we use these dimensions to classify types/roles for benchmarking according to where they sit in these dimensions. This is useful in spelling out the different types of benchmarking that are possible. It is also useful prior to discussing the different types of benchmarking already undertaken by the AER in section 7 (where we examine some illustrative case studies).

4.1. "Pure statistical" and "expert" benchmarking

63. One dichotomy can be imagined between two different approaches to benchmarking. On the one hand there is an approach that relies purely on statistical analysis when attempting to assess the reasonableness of a business's expenditure forecast. On the other hand there is an approach that relies on expert analysis and opinion of the business's expenditure forecast.

64. This is an artificial distinction in that statistical analysis often can and does form an input into expert opinion. That is, the choice of approach to benchmarking is not an 'either or' choice – both approaches can be used in combination. Pure statistical benchmarking can be used but the results can, and in the ENA's view should, be 'sanity tested' by experts. This expert review can take into account knowledge, facts and data that are not suitable for use in statistical analysis – but which can nonetheless be highly informative in assessing the reasonableness of expenditure forecasts.

65. By way of illustration, consider a business proposing to invest in a program of capacity augmentation over the next five year regulatory period. In order to assess the efficiency of the expenditure forecast the AER needs to form an opinion on whether this augmentation strategy is efficient. This requires the AER to determine whether

there is an alternative strategy that delivers the efficient level of reliability/quality of service at a lower cost.

66. It is difficult to conceive of the AER being able to attempt to answer this question without data and knowledge drawn from outside the business proposing the augmentation plan. The AER will need to, directly or indirectly, rely on observed performance of electricity distribution businesses as a group when assessing the reasonableness of this specific expenditure plan. That is, 'benchmarking' of some kind will be required.

4.1.1. Expert benchmarking

67. One way of arriving at an assessment of the proposed expenditure plan is to ask an expert engineering firm to assess the reasonableness of the investments set out in the plan. They will be able to offer an opinion that reflects:

- their industry knowledge (both technical engineering knowledge and knowledge of best practice network planning procedures gained through working in the industry); applied to
- the circumstances of the business (e.g. their network design, available alternatives given that network design, the level of spare capacity in the relevant regions of the network, forecast demand growth, reliability standards etc.).

68. The application of the expert's knowledge of best industry practice network planning procedures to the circumstances of the firm in question is clearly a form of benchmarking (given the definition used in this submission). It involves the expert:

- *starting with raw data* — namely, the relative costs and practices of all the distribution businesses that the expert engineering firm has worked for or studied in the past;
- *identifying industry wide cost drivers* — that is, based on the above experience and engineering knowledge, the expert develops a model that describes the reasons for different approaches taken in different circumstances by these businesses. This model might be a 'formal model' that has been written down and codified in some form or it might be an informal model that is, in effect, the institutional knowledge of the expert engineering firm; and
- *applying the cost driver model to the circumstances of the firm* — that is, using expert knowledge described above, along with an understanding of the circumstances of the firm in question, to assess the reasonableness of the proposed expenditure forecasts. To the extent that the expert uses a formal model as part of this assessment the expert may need to take into account facts that are relevant but not captured in that formal model.

4.1.2. Pure statistical benchmarking

69. An alternative approach to that described above would be to attempt to determine the potential existence of a more efficient plan using statistical methods. Such an approach would involve:

- *starting with raw data* — this data would need to describe the network conditions under which a large number of other businesses have invested in network augmentations and the level of expenditure (and possibly the type of *expenditure*) undertaken in each case. This data would need to be in a form suitable for later statistical analysis. Relevant variables that would need to be measured would include:
  - o dependent variables that capture the different network solutions possible. One might attempt to use "total augmentation expenditure" for this purpose as a relatively blunt but simple single dependent variable[10]; and
  - o independent variables that capture the different influences on the level and type of investment that is made (e.g. some sort of measure of latent capacity for the businesses in the sample at the time that their investments were made, rates of projected demand growth at the time the investments were made; network design differences that influence the level/type of investment made given the other independent variables);
- *identifying industry wide cost drivers* — using statistical analysis of this data a statistician would attempt to determine the relationship between independent variables (cost drivers) and the level of network augmentation expenditure that is, on average, associated with any given set of independent variables; and
- *applying the cost driver model to the circumstances of the firm* — the statistician could then measure the independent variables that reflect the circumstances of the businesses in question. Once measured these could be 'plugged into' in the statistical model derived in the previous step. This would give a prediction of what expenditure on network investments/solutions, on average, would have been built by other businesses if they had the same independent variables (i.e. were in the same circumstances) as the business putting forward its expenditure proposal. This can then be compared with the business's proposed expenditure and a conclusion about the efficiency of this proposal reached.

4.1.3. A combination of approaches

70. A pure statistical approach will not necessarily give estimates that are sufficiently robust for the regulator to rely solely on them when assessing an expenditure proposal. In these circumstances it will be necessary to augment, or supplant, the statistical analysis with expert analysis and opinion.

71. Expert analysis and opinion will tend to be required where:
    - there are more than a small number of independent variables (factors that influence what expenditure should be undertaken);
    - the interactions between these independent variables is complex (non-linear) — for example, where the specific combination of network design/asset

[10] A more nuanced approach would identify numerous dependent variables (e.g. investment in zone substations of different sizes, high voltage feeders, low voltage augmentations and non-network demand management solutions). This would allow the statistical analysis to say something about the type of investment that one can expect in a given circumstances.

age/demand growth/existing latent capacity gives rise to a particular type of augmentation plan that would be radically different if any one of these four independent variables was different[11];

- where the independent variables cannot easily be quantified in a manner that can be used in statistical analysis — for example, differences in existing network designs (e.g. the mix of transmission, sub-transmission, high and low voltage assets, overhead versus underground assets etc) between businesses are unlikely to lend themselves to quantitative as opposed to qualitative measurement. This means that these differences have to either be ignored, or dummy variables assigned to businesses that have the same or 'similar' network designs[12]; and/or
- where there are a small number of observations from businesses (in the context of the above example the observations that are relevant are augmentation expenditure programs over a five year period).

72. In these circumstances, an expert with a technical understanding of the interactions between independent variables is likely better placed to make an assessment. That is not to say that no formal statistical analysis is useful in assessing network augmentation expenditure. The case study in section 7.2 provides an example where formal statistical analysis was undertaken by Nuttall Consulting as the first step of the assessment analysis, but which was followed up with detailed expert analysis of the type described above. This case study provides a useful illustration of the potential problems/pitfalls associated with attempting to rely on pure statistical analysis.

73. This case study is typical rather than atypical of how benchmarking is used in expert engineering assessments. Indeed, page i of the executive summary of the recent Nuttall Consulting review of Aurora's capital expenditure program describes the methodology used as follows:

> *To undertake this review, we have used a number of different analysis and review approaches, which we consider are consistent with the requirements of the NER [the Rules]. These have included:*
>
> - *benchmarking analysis of Aurora's total capex with the capex of Distribution Network Service Providers (DNSPs) in the other National Electricity Market (NEM) states;*
> - *benchmarking analysis of specific components of Aurora's capex with similar capex components of the Victorian DNSPs;*
> - *comparative analysis of Aurora's capex unit costs;*

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[11] By way of example, a particular combination of these independent variables may mean the most efficient investment is to build a large zone substation mid-way through the next regulatory period. However, if demand growth were slightly smaller it may be more efficient to build one small zone substation midway through the next regulatory period and another smaller zone substation early in the next regulatory period.

[12] If all network designs are in important ways unique then this would render pure statistical analysis impossible (as all observations would have a dummy variable).

- *age-based replacement modelling and benchmarking;*
- *review of the policies, procedures, and forecasting methodologies associated with the capex forecast; and*
- *detailed review of a selection of project/program reviews.*

74. It is noted that of the six different methodologies described, the first four are explicitly described as “benchmarking”. The ENA further considers that the last two methodologies described are also a form of benchmarking (that is, using knowledge that Nuttall Consulting has gained in working for a range of businesses to assess the reasonableness of Aurora Energy’s policies, procedures and specific expenditure proposals.

4.1.4. Summary

75. Statistical analysis in benchmarking can conceivably be used by a regulator as the first and only step in a process of examination and testing of a business’s expenditure proposals. Undertaken in this way, no detailed examination of a business’s expenditure forecast is carried out. Indeed, there is no need for a business to prepare and deliver a detailed expenditure justification to the regulator because it would play no role in the regulator’s decision making. However, there are issues in adopting this approach and these are discussed in the next section of this submission.

76. A more prudent approach would involve using statistical benchmarking techniques as one of the first steps of the analysis in order to identify areas of a business’s expenditure forecasts that are unusual given the patterns observed for other businesses. If anomalies were identified, further detailed examination would then be undertaken in an attempt to understand whether there are good reasons, not capable of being identified in the statistical analysis, why the anomaly exists. As set out in the case studies discussed in section 7, this is generally how statistical benchmarking has been used by the AER to date.

4.2. Benchmarking against the businesses past activities

77. A business’s proposed expenditure, and the activities/assets that this is to be spent on, can be benchmarked against its past expenditure/activities rather than comparisons made with like businesses. This can be done based on the past level of expenditure by the firm, but also based on other attributes of the business management. For example, if a business is proposing replacement expenditure based on a useful life of 20 years, but its past retirement of assets has been, on average, at 25 years then there may be a case for only compensating based on what the business has done in the past.

78. This process is at the heart of incentive regulation. It involves giving a business an incentive to lower its costs, observing any resulting cost reduction and using this to inform future expenditure allowances.

79. This approach attempts to solve the problem of adjusting for differences in circumstances by benchmarking against the business that faces the most similar circumstances to the business in question (i.e. itself).

4.3. Benchmarking at different levels of aggregation

80. Benchmarking can also be undertaken at different levels of aggregation of a business's costs. This is as true for statistical approaches to benchmarking as it is for the expert analysis approach to benchmarking. For example, benchmarking can be undertaken at the level of:

- total expenditure;
- operating and/or capital expenditure separately; and
- different elements of operating and capital expenditure such as:
  - replacement capex;
  - augmentation/reinforcement capex; and
  - vegetation management, pole replacement, etc.

81. Consider the practical example used for illustrative purposes in the previous section. In that case the level of aggregation of expenditure was all capital expenditure relating to augmentation of network capacity. This level of aggregation would, putting aside measurement problems, not include replacement capital expenditure (expenditure on replacement of existing assets at the end of their useful lives), power quality related expenditure (e.g. low voltage conductor upgrades in response to voltage complaints by customers), reliability related expenditure, non-network general IT, non-network motor vehicle and property expenditure etc.

82. Alternatively, a higher level of aggregation could be used that might, for example, lump together expenditure on both augmentation and replacement. Similarly, a lower level of aggregation could be adopted that, instead of looking at all augmentation expenditure, focussed only on a subset of it. For example, augmentation capital expenditure could be broken up into the high voltage network, distribution substations and the low voltage network.

4.3.1. The optimal level of aggregation

83. The optimal level of aggregation for any benchmarking analysis depends critically on:

- capturing interdependencies (substitutability) between different types of expenditure;
- limiting the number and variety of causal factors that need to be accounted for (especially if pure statistical benchmarking is to be relied on);
- whether the benchmarking exercise is purely statistical or whether it allows a role for expert engineering analysis and opinion; and
- the costs and benefits of capturing and analysing the relevant data.

4.3.1.1. Capturing interdependencies

84. The level of aggregation needs to be high enough such that material interdependencies between different expenditure types are captured in the analysis. For example, network augmentation expenditure on the sub-transmission system may be a substitute for augmentation expenditure on the distribution system and vice versa.

85. If analysis of the sub-transmission expenditure is undertaken without regard to the level of distribution system expenditure being undertaken, then the researcher may incorrectly conclude that a business spending more than average on its augmentation of the sub-transmission network is inefficient, even though this business may be efficient overall (with savings on distribution system augmentation expenditure more than offsetting the higher than average expenditure on augmenting the sub-transmission network).

86. This problem may be able to be ameliorated by adding together distribution and sub-transmission augmentation expenditure. Doing so will help avoid the problem described above but it may introduce more problems. For example, distribution system augmentation expenditure may be a substitute for some kinds of reliability expenditure (e.g. building a new distribution substation and associated works may also solve some reliability problems that otherwise would require separate expenditure).

87. Similarly, augmentation and replacement capital expenditure do not, in reality, have a bright dividing line between them. Significant spending on replacement of assets can also be associated with augmentation to the capacity of the network. For example, at the time of replacement of an aged transformer it will often be efficient to increase the capacity of the transformer. Indeed, a need to augment capacity in a region may mean that the optimal replacement time of some assets is brought forward so that they can be replaced with larger capacity assets.

88. This substitutability between replacement and augmentation capital expenditure may lead the researcher to want to include both augmentation and replacement capital expenditure in the benchmarking exercise. However, if this is done then the researcher is immediately faced with the problem of substitutability between replacement capital expenditure and maintenance expenditure. This is because newer assets tend to have fewer faults and require less maintenance expenditure.

4.3.1.2. Limiting the number of causal factors that need to be examined

89. One can see from the discussion above that an attempt to ensure that substitutability between different expenditure types is captured can very quickly lead the researcher to want to include all, or nearly all, expenditure in the benchmarking analysis. However, such an approach quickly runs into the second constraint, namely, the need to keep the number of causal factors (independent variables) to a tractable level.

90. The higher the level of aggregation across activities, the greater the number of causal factors that must be taken into account in a benchmarking analysis becomes. For example, there may be three or four causal factors that determine the expenditure on replacement of a particular asset like street transformers (including for example. the

number of these assets, their costs of replacement, the average remaining life of these assets, the distribution around the average, the type of street transformer used and the climatic conditions in the region they are installed).[13]

91. However, if the benchmarking exercise is undertaken at the level of total replacement expenditure (or even at a higher level) then the number of independent variables will be many times this (i.e. the same or similar independent variables for each and every asset class). If the benchmarking exercise is undertaken at the level of the total replacement capital expenditure proposal (rather than its constituent parts) then there will be only one dependent variable (total replacement expenditure) but a large number of independent variables (all of the factors that determine the expenditure in each subcategory of replacement expenditure).

92. This discussion highlights why a conclusion arrived at using purely statistical techniques with highly aggregated data is unlikely to be robust. In fact, with only a dozen or so businesses to draw data from, there may well be more independent variables than total observations, rendering a purely statistical approach to benchmarking not just non-robust, but actually impossible.

93. One can potentially address this problem by using observations from foreign firms or attempting to use historical data for each firm. However, adding foreign firms to the sample will likely mean that it is necessary to introduce additional independent variables (e.g. exchange rates and reliability standards) and the data for these firms would be unlikely to be easily compared with data collected domestically[14]. It is not obvious that the benefits in terms of more observations of dependent variables from foreign firms would offset the costs of having to deal with more independent variables. Similarly, given the existing problems with domestic data, it is not obvious that a useful time series will be able to be developed going backwards in time from today (although improvements in domestic data collection may make it possible to develop such a time series over time).

4.3.1.3. Aggregation and benchmarking using engineering expert analysis

94. Given the problems associated with large numbers of causal factors, statistical benchmarking can most robustly be used at a relatively low level of aggregation (see discussion of the case study on replacement capex benchmarking in section 7.2).

95. This does not mean that benchmarking should always be carried out at the 'lowest' level of aggregation possible. Rather, there will tend to be a 'sweet spot' where the level of aggregation is not so high such that there are too many independent variables must be modelled and in a way that makes it problematic for the results to be reviewed by engineering experts. However, the level of aggregation will not be so low as to fail

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13 However, even at low levels of aggregation there can still be a large number of independent variables. For example, one member has participated in a benchmarking study relating to gas pipeline laying costs and the following relevant independent variables were identified: number of feet of new distribution main piping installed, -soil type, developed locations, undeveloped locations, surface type, type of backfill, length of job, type of shoring used, pipe size, joining methods, level of compaction required, obstructions, traffic control and extra depth required.

14 See the criticisms of the Mountain (2012) report discussed in Section 7.6.

to group like activities together and to multiply the costs and time of review (e.g. if every expenditure line needed to be benchmarked).

96. Alternatively, if statistical analysis is carried out at a high level of aggregation, it is best used as the first step in the analysis rather than the basis to determine efficient costs (see discussion of the case study on augmentation capex benchmarking in section 7.3 and total operating expenditure in section 7.4).

97. In contrast to pure statistical benchmarking, benchmarking via the use of expert analysis allows for a greater number of causal factors to be accounted for in the analysis in a more detailed fashion. In effect, this approach has the potential to simultaneously perform benchmarking at an aggregated and a disaggregated level.

98. By way of example, the case study in section 7.3 provides an example of how the expert, in this case Nuttall Consulting, was able to form an opinion about Aurora's proposed capital expenditure on a new zone substation by reference to facts the expert could take into account about Aurora's proposed operating expenditure program (and the internal consistency of these):

> *In the case of the Sandford augmentation, we consider that Aurora is proposing a very costly solution, involving the development of sections of underground and submarine sub-transmission lines operating temporarily as HV feeders. While we agree that this solution is in line with the longer-term strategy to develop a new substation in that region, our view is that a much lower cost, short-term, solution most likely could be found, assuming more rigorous analysis is undertaken. Moreover, Aurora is also proposing a non-network solution to defer the need for the related new Sandford zone substation project. We do not consider that Aurora's capex (and opex) allowance for this non-network solution is consistent with the assumption that this network project will be required also. Our view is that the non-network solution will most-likely mean that a network solution will not be required in the next period. This matter will be discussed further in Section 5.5.2 on Aurora's non-network plans.*[15]

4.3.1.4. Aggregation and benchmarking using purely statistical analysis

99. One could attempt to perform aggregate statistical analysis with only a small number of very high level independent variables as proxies for cost drivers. These could be things like kilometres of line, peak demand, and customer density.

100. However, such an approach is as likely to simply disguise the problem of too many independent variables rather than to solve it. This is because substituting very high

[15] Nuttall Consulting, Report – Principle Technical Advisor Aurora Electricity Distribution Revenue Review, 11 November 2011, Page 42

level independent variables inevitably means the loss of relevant information compared to the information an expert reviewer is able to take into account.[16]

101. Perhaps more importantly, high level aggregate benchmarking with the use of a few high level causal factors makes it impossible to 'sanity check' the results that come out of a statistical model with the real world engineering constraints facing a business. If the regulator determines that expenditure on zone substation is not efficient because less costly alternatives exist, then this is a finding that can be contested on the available facts.

102. By contrast, consider an example where a regulator decides that five percent of total expenditure is not efficient purely on the basis of a high level statistical comparison to other businesses. This reasoning provides no indication of what aspects of the expenditure proposal are imprudent. Consequently, the business has no recourse to defend its proposed asset investment program on the engineering needs of the business because this was not the basis of the regulator's finding.

103. This is one of the most significant risks associated with the use of statistical benchmarking performed on a highly aggregate basis. Such benchmarking does not, in its nature, provide any indication of where within the aggregate that the business is inefficient. The only finding is that 'somewhere' within the aggregate the business is inefficient.

104. This makes it impossible for an efficient business to respond by pointing to facts and evidence not captured in the statistical analysis which demonstrates that they are not inefficient. While the business may deliver faultless demonstration of the need for all expenditure programs, if the regulator's decision is based purely on high level statistical analysis then such a faultless justification of the required expenditure can be ignored (indeed, must be ignored in a purely statistical approach).

105. This in turn creates a threat to the property rights of investors. If a regulator could disallow recovery of a material proportion of a business's necessary expenditure without providing any indication of the areas of that expenditure it considered

16 Consider two businesses that have identical network architecture and size today and identical average age of all assets. However, let one business have grown steadily over time so that the distribution around their asset ages is broad and smooth. However, imagine that other business has grown in fits and starts – such that the distribution around their average age is 'humped' (with clusters of assets of similar age reflecting the times that they grew the fastest and therefore needed to install more assets than at other times).

In this example, we expect the second firm (with the fits and starts growth) to have a very different profile of asset replacement than the first firm (with the steady growth). The second firm will have high replacement costs in a given asset class as any 'hump' for this asset class approaches the end of its useful life. At other times it will have low replacement costs.

This difference between the firms' replacement expenditure profiles exists even though the two firms have been assumed to have an identical network design and identical average age of assets. In order for statistical benchmarking of five year expenditure forecasts to take this into account there needs to be independent variables that captures the approach to the end of their useful life of any such humps in individual asset classes age profiles.

In summary, a statistical approach needs to either ignore potentially significant causal factors, perhaps in the hope that they will cancel each other out over time, or must be carried out at the level of individual asset classes.

excessive, then investors may be unable to recover the headline return on their past investments. That is, some of the regulatory return on capital allowed by the regulator will need to be diverted to fill the gap between necessary expenditure and allowed expenditure. In effect, this is an expropriation of past investment used by the regulator to fund future expenditure.

106. By contrast, statistical benchmarking applied at a disaggregated level does allow a business to respond with engineering facts in order to demonstrate their efficiency. For example, the replacement expenditure benchmarking case study discussed in section 7.2 describes, amongst other things, how Nuttall Consulting has used statistical benchmarking against peers to arrive at the conclusion that Aurora Energy's proposed expenditure on pole replacement is excessive.

107. By performing statistical benchmarking at this low level of aggregation the business has the opportunity to respond with facts and evidence specific to its pole replacement program. For example, to justify why it plans to replace poles at an earlier age than has been the case in other jurisdictions. If the business has valid reasons for why it plans to replace poles at an earlier time than other businesses it has the opportunity to provide the AER that justification. It would have no such opportunity if the statistical benchmarking relied on by the AER was performed at a more aggregate level.

108. Similarly, the business also has the opportunity to argue, based on understood engineering/economic principles, for the inclusion/exclusion of particular cost drivers in the statistical model. However, at more aggregate levels there is a much less clear engineering/economic basis for including cost drivers. For example, it may be that poles are twice as expensive in one jurisdiction compared to the other (e.g. due to different proximity to a hardwood industry – noting that poles are expensive to transport). This input price difference can more easily be included in a statistical analysis of pole replacement than it could be in a statistical analysis of total capital expenditure.

4.4. Benchmarking unit versus total costs

109. It is also possible to distinguish between benchmarking unit costs versus total costs. By way of example, one might use a process for determining the total number of poles it is efficient to replace (which could be purely statistical benchmarking or include expert analysis benchmarking). A separate benchmarking process could then be used to determine unit costs. The vegetation management case study in section 7.5 describes the use of unit cost in benchmarking analysis.

4.5. Summary of categorisations

110. The distinctions between the different approaches to benchmarking are summarised in the below table. Also categorised in this table are examples of benchmarking discussed in the case studies in section 7. Each cell of this table describes a particular approach to benchmarking. For example, cell A1 (corresponding to Row A and column 1) describes the approach the AER has taken to the use of benchmarking aggregate operating expenditure. Not explicitly captured in this table is benchmarking against a business's past costs and benchmarking of unit costs.

Table 1: Categorisation of different approaches to benchmarking

	Pure statistical benchmarking used to "shine a light" looking for areas requiring further close inspection (1)	Pure statistical benchmarking used to establish the level of compensation that the regulator will allow for that activity (2)
High level aggregates of expenditure (A)	AER opex benchmarking section 7.4	None
Lower level expenditure categories (B)	Pole replacement example in section 7.2* and augmentation capex benchmarking example in section 7.3	Pole replacement example in section 7.2*

* This example somewhat straddles 1B and 2B given that the end expenditure allowance gives significant weight to the statistical benchmarking.

5. Making like-for-like comparisons in electricity transport

111. The previous section has already discussed some of the difficulties in adjusting for different cost drivers across businesses. However, this is a vital issue when considering the use of benchmarking, especially statistical benchmarking performed at an aggregate level, for network electricity businesses.

112. There are many cost drivers that affect the operating environment for a business and, consequently, the observed costs for a business. Benchmarking provides useful information on efficient costs if it enables a like-for-like comparison – including by making robust adjustments for differences. Amongst other things, these cost drivers for electricity businesses include differences in:

- input prices (e.g. labour and capital costs (including capital rental costs);
- output delivered, including different levels of formal reliability standards that need to be met, as well as other ways in which output can vary across businesses (e.g. differences in workforce safety levels, impact on environmental amenity (e.g. undergrounding cables rather than overhead cables) etc);
- levels of latent capacity from past investment cycles;
- network design that reflects historical decisions made over the last 50 or more years;
- asset ages reflecting, amongst other things, differences in the timing of demand growth in the past;
- network 'size' that allows for some economies of scale;
- the economies of scale that two similarly sized businesses can achieve due to differences in the pattern of past demand growth:
    - for example, one business that has had low and steady growth in the past will tend to (efficiently) have a large number of smaller transformers and other equipment that will need to be operated and maintained. By contrast, a business that has experienced large waves of growth will (efficiently) have a smaller number of large scale assets that need to be operated and maintained (because large scale assets can be built with less average underutilisation when demand is growing faster); and
    - note also that past overinvestment in large scale assets (overinvestment in the sense that the assets spent an inefficiently long time underutilised) may also give rise to apparent (but illusory) levels of high efficiency today;
- customer density that can affect the optimal size and number of transformers and other assets used in the network:
    - noting also that density may have a non-linear U shaped relationship with total costs. That is, very low and very high density may result in higher costs than 'middle' density. High density may cause higher costs if, for example, it requires substations to be built underground/in basements of buildings;

- topography between regions;
- weather/climatic conditions in each region (e.g. rainfall, flooding, humidity, frequency of high wind events, lightning strikes etc). For example, vegetation management costs, asset deterioration and storm related outages can be affected by climatic conditions;
- aspects of urban density (e.g. that affect town planning, environmental impacts, traffic management etc.); and
- applicable environmental, planning and development standards/laws.

113. In relation to the third dot point, a Productivity Commission staff working paper has recently made a very similar point.

> *Given the periodic or cyclical component to capital infrastructure investment in ES, some part of the recent build up in capital capacity (particularly in the network) is likely to be in the form of lumpy capital assets that are designed to underpin growth in demand well into the future, not just to meet current demand. The consequences for MFP are twofold: first, MFP growth in recent years will have been lower than would otherwise have been the case. An increase in investment in long-lived capital assets that will not be fully utilised until sometime in the future will have put (temporary) downward pressure on MFP. Second, once the current investment cycle is completed, output is likely to grow while labour and capital input growth is likely to moderate. These developments will have positive effects on measured MFP. Underlying growth in MFP will not be clear until these developments play out.*[17]

114. If two otherwise similar businesses are in a different phase of this investment cycle it means that expenditure proposals can be radically different. This is just one problem with making aggregate expenditure like-for-like comparisons using purely statistical means.

5.1. Degrees of freedom in statistical analysis

115. As already discussed, two broad approaches are possible in order to make a like-for-like comparison given the impact of these cost drivers:
    - attempt to let the data 'speak for itself' – using cost and cost driver data from each business as an input into econometric techniques in order to determine the relationship between cost drivers and costs; and
    - use expert knowledge and known 'engineering relationships' in order to make adjustments to observations in line with that knowledge.

[17] Tony and Kulys (2012) *Productivity in Electricity, Gas and Water: Measurement and* Interpretation, Ch. 4, p.53.

116. Of course, the data is only capable of 'speaking' coherently if there are a large number of observations of the dependent variable relative to the number of independent variables. As previously discussed, this is unlikely to be the case at high levels of aggregation. This is because the number of relevant cost drivers' increase - but the number of observations does not as different types of expenditures, with different cost drivers, are lumped together.

117. Pedraja et al,[18] estimate that, even if the model specification is perfect (i.e. all cost drivers are included) a very large number of observations would be needed, given the level of measurement error assumed by Pedjara et. al. Specifically, in order to achieve a (minimally) robust estimate of efficient costs. Pedraja et al, estimate that if there were just two cost drivers one would need twenty observations. With three cost drivers one needs 80 observations. With four cost drivers one needs 160 observations etc. We have listed ten cost drivers above – most of which are really multiple cost drivers and which are unlikely to have a linear relationship with costs.

5.2. Data quality/comparability

118. Data quality is another important requirement for robust statistical benchmarking. The case study in section 7.5 relates to vegetation management benchmarking. One of the issues illustrated in this case study is that not all businesses record the same activities in the same way in their accounts. In particular, what was recorded as vegetation management for Powercor was not necessarily the same as what was recorded as vegetation management at businesses that the AER was using in its benchmarking. Similarly, different business can have materially different approaches to capitalisation policy – meaning that recorded operating expenditure and capital expenditure can cover different activities at different businesses. An important component of any plan to increase the accuracy and use of statistical (and expert) benchmarking must involve an attempt to harmonise the manner in which management accounting data is recorded.

119. The AEMC has, in its assessment of the use of TFP benchmarking, identified data quality as an important hurdle to the more widespread use of statistical benchmarking.

> *However, a number of conditions need to be satisfied for a TFP methodology to work properly and promote efficient regulatory decisions. We find that such conditions are not likely to be met at the present time. Crucially, the current lack of a sufficiently robust and consistent data-set means that it could be too problematic to reconstruct existing data for the purpose of a TFP methodology. Also the lack of data prevents proper testing of the other conditions needed for a TFP methodology. We advise*

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18 Pedraja, F.; Salinas, J; Smith, P. (1999): On the quality of the Data Envelopment Analysis model. Journal of the Operational Research Society, 50, 636-645.

that the initial focus should therefore be on establishing a better, more consistent data-set.[19]

[19] AEMC, FINAL REPORT Review into the use of total factor productivity for the determination of prices and revenues, page ii

6. Criteria and scope for good benchmarking

120. The following criteria for the use of statistical benchmarking were developed by Frontier Economics for Ofgem.[20]

- **robustness** — the benchmarking process and the resulting performance assessment must be regarded as robust by the operators and peer reviewers. A technique that produces results that are not sufficiently robust will be of little use in a regulatory context and will struggle to stimulate information revelation;
- **consistency with the wider regulatory framework** — benchmarking should foster the high level objectives of the wider regulatory regime and strike an appropriate balance between different objectives. Benchmarking should also encourage operators to innovate while providing appropriate protection from unnecessary expenditure for customers;
- **transparency** — if benchmarking methodologies are clear it will aid the ability of all stakeholders to understand the rationale for the selected approach. It will also be clear to the operators what conduct is being encouraged;
- **promotion of efficiency** — benchmarking techniques should promote not just efficient cost management, but also strike an appropriate balance between low costs and desired outputs. Benchmarking methodologies should also minimise the extent to which they distort incentives to favour one cost type over another;
- **reasonableness of data requirements** — any benchmarking technique will only have merit if the necessary data exists to populate it;
- **adaptability** — given the likelihood of material changes in the availability and relevance of certain data over time as network roles evolve, there is merit in pursuing a benchmarking technique that can adapt and remain fit for purpose; and
- **resource cost** — approaches that impose significant additional cost on Ofgem and the regulated operators should only be adopted if they deliver materially better information.

121. We consider these criteria to be reasonable. However, we also consider that they involve insufficient direction as to how to assess when the criteria are satisfied and how to deal with potential trade-offs between the criteria.

122. The ENA's view is that the requirements for regulatory decision making set out in the NEL and Rules provide appropriate guidance on this matter. Specifically, benchmarking will be sufficiently robust and consistent with the wider regulatory framework where it:

[20] RPA-X@20: The future role of benchmarking in regulatory reviews, May 2010. Available at http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/rpt-benchmarking.pdf

- provides a network service provider with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing the regulated services (NEL section 7A(2) Revenue and Pricing Principles)[21]; and
- reflects the costs that a prudent operator in the circumstances of the relevant business would require to achieve the capital and operating expenditure objectives. (Rules 6.5.6 (c)(2) and 6.5.7(c)(2)).

123. Benchmarking can and should be used to achieve these outcomes. Where a particular form of benchmarking cannot, on its own, be used to achieve these outcomes it should not be solely relied on. However, it can be relied on as one relevant source of information.

124. The ENA notes that the AER has argued to the AEMC that Rules 6.5.6(c)(2) and 6.5.7(c)(2) restrict it from using benchmarking by requiring analysis to reflect the circumstances of the firm in question. The ENA's position is that this is incorrect. These Rules only restrict the AER from performing poor quality benchmarking that does not make the appropriate adjustments for differences in cost drivers between businesses. In this regard the ENA agrees with the statements made by Professor Yarrow in his recent preliminary advice to the AEMC:

> *By way of example, consider the issue of benchmarking. The evidence indicates that the AER has and does adopt benchmarking approaches, so the argument must be that the regulator would like to make greater use of the approach but is precluded from doing so by sections of the rules that indicate that assessments need to be made which reflect the actual circumstances of the regulated firm.*
>
> *I cannot, however, see how any regulator could not be focused, in a particular decision, on the particular, specific context of that decision (the particular circumstances). Academics may be free to solve abstract problems; regulators are not.*
>
> *This does not mean that information from benchmarking cannot be used. In fact, benchmarking information has value only insofar as it contains information relevant to an assessment of performance in particular circumstances: the greater its implications for assessment of the particular circumstances, the greater its value for the specific purpose at hand. Benchmarks that are uninformative for the assessment of the performance of a particular utility, in its own particular context, are, in fact, valueless, and should not be used, even when the regulator has discretion to use them. It*

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21 Section 7A(2) states that: "A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

is therefore not clear to me that, even on a relative narrow interpretation, the rules do anything other than preclude uninformative benchmarking.

If, however, it is concluded that the existing rules do overly-constrain the AER's use of benchmarking, the appropriate remedy is to remove the relevant restrictions. I do not think a case has been established to go further than this, for example by mandating certain types of benchmarking. The assessment of relevant information in a given case is a technical exercise, and it would likely prove difficult to provide sensible guidelines, in a set of general rules, on the relative weights to be given to the different pieces of information that might be available (and see footnote 1).[22]

125. In this context it is useful to think about how businesses use benchmarking outside of the regulatory context. Businesses can and do commission studies that conclude that they incur higher costs than other comparable companies in performing a particular necessary function. Such information would be used as a high level indicator that the activity was inefficient and set the basis for further, more detailed and business-specific review. The ENA submits that a regulator should follow a similar approach.

[22] Professor Yarrow, Preliminary views for the AEMC, page 17.

7. Benchmarking examples

7.1. Introduction

126. This section provides several recent examples of benchmarking:

- Nuttall Consulting's assessment for the AER of replacement and augmentation capex proposed by Aurora Energy[23] (sections 7.2 and 7.3);
- the AER reflecting on its experience in assessing the reasonableness of total expenditure forecasts using aggregate benchmarking (section 7.4);
- the AER's use of benchmarking in relation to vegetation management for Powercor (section 7.5); and
- two studies by Bruce Mountain for the Energy Users Association of Australia (EUAA) that make broad claims about network business productivity and prices (section 7.6).

127. Broadly, the Nuttall Consulting material demonstrates the potential value of expert analysis benchmarking. The AER's reflection on aggregate benchmarking provides a useful summary of why, according to the AER, the results of this analysis are not robust and are best used as a 'first step' of analysis rather than a 'final step'. The AER vegetation management example and the Mountain material (sections 7.5 and 7.6) demonstrate the dangers of drawing incorrect or unjustified conclusions from limited statistical benchmarking.

7.2. Replacement capex

128. This section examines Nuttall Consulting's use benchmarking for the AER to assess the reasonableness of expenditure forecasts relating to the replacement of ageing or faulty assets. In doing so this example highlights:

- how Nuttall Consulting used formal statistical analysis as the first step of the assessment analysis and how this was followed up with detailed expert analysis of the type described above;
- the flexibility with which an expert with a technical understanding of the interactions between independent variables is able to have regard to information that would be difficult to include in a pure formal statistical analysis;
- how statistical benchmarking can and is used to measure a business's performance:
    - o against its past performance; and
    - o against the performance of peers; and

23 Available at http://www.aer.gov.au/content/index.phtml/itemId/750924.

- how statistical benchmarking applied at an appropriately disaggregated level allows a business to respond with engineering facts in order to demonstrate their efficiency.

129. The AER retained Nuttall Consulting to advise on the reasonableness of Aurora Energy's proposed capital expenditure program. Section 6 of Nuttall Consulting's report deals with non-demand related capital expenditure (i.e. network related capital expenditure that is not driven by growth in peak demand).

130. This section, and the Nuttall Consulting report more generally, provides a useful resource for the Productivity Commission to understand how benchmarking should be used by the AER and its consultants. Section 6.1 of the report provides an overview of Aurora Energy's proposed non-demand capital expenditure plan. Section 6.2 provides high level benchmarking of this against peers identified by Nuttall Consulting (being the Victorian electricity businesses). Nuttall Consulting concludes:

> *Based upon this analysis, Aurora appears to have spent and is forecasting to spend on average 50 - 80% above the Victorian DNSPs in capex per km, when adjusted for scale and density. With regard to its two closest peers, Powercor and SP AusNet, Aurora's capex forecast for the next period, it is approximately 60% greater than Powercor and 30% greater than SP AusNet, adjusting for scale and density.*

131. However, Nuttall Consulting goes on to note that the statistical analysis is not complete and omits potentially important factors that might affect aggregate non-demand capital expenditure:

> *There are a number of factors that could affect the comparison of Aurora's expenditure with the Victorian DNSPs, many of which should favour Aurora with regard to the level of capex required in these categories.*

132. Nuttall Consulting goes on to list these in a descriptive way noting the likely direction of the effect. Nuttall also lists some important factors that he was unable to gather relevant information. However, Nuttall Consulting concludes:

> *Nonetheless, we consider that the analysis supports a view that Aurora may not be managing assets in a prudent and efficient fashion. At the very least, these findings support the need for our detailed review of Aurora's capex in these categories.*

133. Nuttall Consulting then goes on to examine disaggregated components of the non-demand expenditure. The major component of which is replacement of ageing and faulty assets – which Nuttall Consulting examines separately for each asset class. In doing so, Nuttall Consulting continues to rely on statistical benchmarking techniques to assess these disaggregated expenditure items. The statistical benchmarking techniques embodied in Nuttall Consulting's "repex" model (where repex refers to

replacement expenditure). The use of this analysis is, naturally, restricted to areas where Nuttall Consulting considers the relevant data is available:

> *The repex model has been used to assess the replacement component of the non-demand capex. For Aurora, the repex model was developed for the asset categories where appropriate data was available. This represents the majority of the replacement capex. The main asset categories excluded were "services", "distribution other", "zone substation other", and the "other" asset categories. The "distribution switchgear" category has been modelled, but overhead-line switchgear has been excluded from this category. These exclusions were due to either the absence of suitable age profiles or expenditure data.*

134. Nuttall Consulting states that it has developed two models – one benchmarking against past Aurora Energy performance and one benchmarking against peers:

> *We have applied a similar process to that used in our analysis of the Victorian DNSPs. This has involved the development of a "calibrated model", where asset lives and unit costs are calibrated to Aurora's historical levels.*
>
> *In addition, a "benchmark model" has been developed. The benchmark model uses benchmark lives developed from the set of calibrated lives determined from both the Victorian and Aurora repex modelling.*

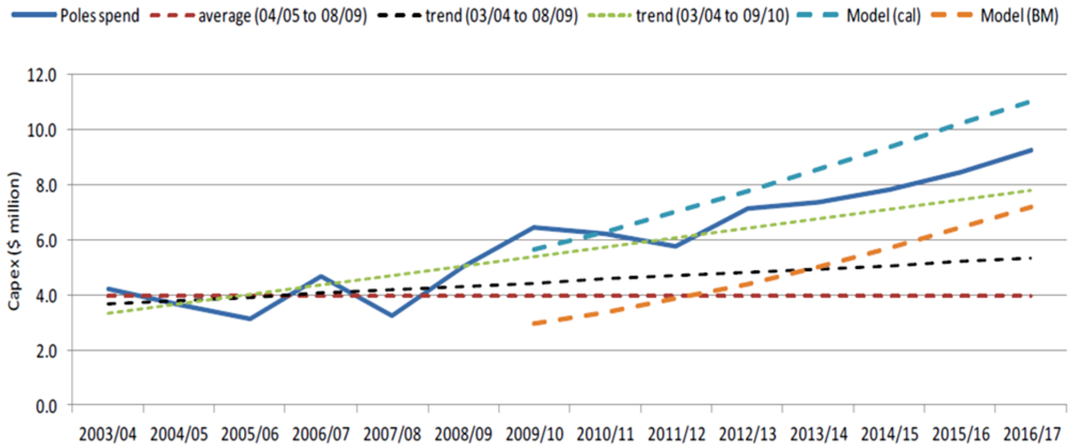
135. Nuttall Consulting performs this analysis at the level of aggregate replacement expenditure and on an asset class by asset class basis. Nuttall Consulting concludes that at the aggregate level:

> *This shows that the calibrated model forecasts a level of replacement capex that is similar to the Aurora forecast in the early part of the next period and higher in the later half. This suggests that Aurora is allowing for longer lives in the next period than it has achieved recently, which could be considered to support a view that its forecast is allowing for further efficiency gains.*
>
> *The benchmark model output supports a much lower level of capex from that forecast by Aurora. Assuming the recent level of replacement by the Victorian DNSPs represents prudent investment levels, then this suggests that Aurora's current asset management practices and/or its forecasting methodologies may be overstating the prudent investment needs of the network.*

136. Nuttall Consulting then goes onto examine each asset class. By way of illustration, consider the approach taken to pole replacement (which, given the rural nature of Aurora's network, contains the largest portion of replacement capital expenditure at 25

percent). Nuttall Consulting examines pole replacement in section 6.3.3.1. The following chart from Nuttall Consulting's report summarises their findings.

Figure 1: Replacement – poles capex trend



Source: Nuttall Consulting, Report – Principle Technical Advisor Aurora Electricity Distribution Revenue Review, Figure 26, from page 80.

137. This figure shows proposed poles spend (unbroken blue line) being below a benchmark calibrated based on Aurora's past spending but above the trend based forecasts (black and green broken lines which differ depending on the end year used to derive the trend) and benchmark based on Victorian businesses.

138. Nuttall Consulting then examined the assumptions and evidence underpinning Aurora's estimates of pole replacement expenditure (pages 80 to 82). Based on that review, Nuttall Consulting identified areas where it believed that Aurora Energy was being overly conservative in its forecast of replacement rates for poles. Nuttall Consulting proposed that the allowance for pole replacement be reduced by $14.7m (around one third of Aurora's original proposal). The magnitude of this estimate was determine and justified on the basis that:

> *This estimate has been calculated by assuming historical expenditures for pole replacements are maintained over the next regulatory period in line with the linear trend (excluding 2009/10). This position places the Aurora forecast far closer to the benchmark repex model, which we consider is reasonable given our findings of the detailed review.*

139. That is, Nuttall Consulting estimated its adjustment based on a historical trend (the black broken line in the above figure) and justified this on the basis that it was similar

to the benchmark based on Victorian businesses. This proposal was adopted by the AER in its draft decision[24].

140. This provides a clear example of where statistical benchmarking has played an important role in the AER's justification for an adjustment to expenditure forecasts. However, it has not taken place in a vacuum. The AER's technical advisers has compared the results of statistical benchmarking (of various sorts) to the expenditure proposal. The advisers have undertaken a review of the modelling assumptions used by Aurora in order to assess whether, in their opinion, a departure from the benchmarks is justified. The adviser has concluded that the modelling is not sufficiently robust to justify such a departure.

141. Finally, but critically, benchmarking carried out in this way gives Aurora the opportunity to respond in a meaningful way. If the AER's adviser has made errors of fact or judgement in their assessment then Aurora can respond to these – both in terms of the statistical modelling and the bottom up modelling of their own costs. Had the analysis been carried out at a more aggregate level without the assessment of Aurora's bottom up expenditure modelling then this potential for contesting of the relevant facts would be seriously muted and would deny the business to appeal to facts not captured in the statistical model.

7.3. Augmentation capex

142. Nuttall Consulting also advised the AER on the reasonableness of Aurora Energy's proposed expenditure on augmentation capital expenditure (i.e., expenditure required to meet growth in peak demand). This is carried out in Section 5 of the Nuttall Consulting report. That section begins with an upfront statement about the different network design that Aurora has compared to most other electricity distribution businesses and the implications of this for how Nuttall Consulting goes about its assessment.

> *It is important to note the difference between Aurora and other NEM DNSPs with regard to the plans that underpin reinforcement capex. Most other DNSPs' proposals have had a number of fairly major projects associated with zone substation and sub-transmission developments that constitute a large portion of reinforcement capex. Often, these DNSPs will use high-level approaches to estimate the required capex at distribution levels.*
>
> *Aurora's proposal on the other hand, owing to Aurora only owning a small amount of sub-transmission and associated zone substations, consists of a very large number of distribution level feeder augmentations. A large portion of these projects have been developed through a bottom-up process. There are only a few projects that could be considered major. Furthermore, many of the projects should be considered as project*

[24] AER, Aurora 2012-17 draft distribution determination available at http://www.aer.gov.au/content/index.phtml/itemId/750924.

complexes (i.e. groups of smaller augmentations that together are aimed at addressing a localised and related set of issues). (Page 34)

143. This illustrates an important theme of this submission, namely, the fact that different network designs (in this case relatively small ownership off sub-transmission assets) will be reflected in different business expenditure proposals.

144. Nuttall Consulting then goes onto perform high level statistical benchmarking of Aurora relative to peers identified by Nuttall Consulting (section 5.2). At page 37 of its report, Nuttall Consulting notes that the analysis suggests that Aurora may be spending around twice the level of its peers after an attempt to adjust for a like-for-like comparison.

> *This analysis suggests that the Victorian DNSPs would have still incurred and are forecasting to incur considerably less than Aurora if the growth rate is adjusted to 1%. Our analysis suggests Aurora is still over twice the Victorian amount for the current and next periods.*

145. However, it is acknowledged that other factors not captured in the statistical analysis may explain at least some of this difference.

> *Another matter that may be causing the increased need for capex in the case of Aurora may be the new reliability standards that were introduced for Transend and have impacted Aurora's capex in the current period. Although Aurora's obligations associated with developing the network to cater for peak demand are similar to Victoria (i.e. they are largely risk based rather than strict redundancy standards), Transend's state-based obligations have resulted in the development of a number of new substations. This in turn means that Aurora needs to develop the distribution network to allow these to be connected and offload the existing substations.*
>
> *It is difficult to quantify this impact in our analysis...*

146. Notwithstanding this caveat, Nuttal Consulting concludes on the basis of the statistical benchmarking that:

> *On balance, we consider that the analysis supports a view that Aurora may not be managing assets in a prudent and efficient fashion. At the very least, these findings support the need for our detailed review of Aurora's capex in these categories.*

147. Nuttall Consulting then moves onto a more detailed analysis of the proposed augmentation. At the heart of this analysis is the substitutability between operating and capital expenditure. We have already discussed how the expert, in this case Nuttall Consulting, was able to form an opinion about Aurora's proposed capital expenditure on a new zone substation by reference to facts the expert could take into

account about Aurora's proposed operating expenditure program (and the internal consistency of these):

> *In the case of the Sandford augmentation, we consider that Aurora is proposing a very costly solution, involving the development of sections of underground and submarine sub-transmission lines operating temporarily as HV feeders. While we agree that this solution is in line with the longer-term strategy to develop a new substation in that region, our view is that a much lower cost, short-term, solution most likely could be found, assuming more rigorous analysis is undertaken. Moreover, Aurora is also proposing a non-network solution to defer the need for the related new Sandford zone substation project. We do not consider that Aurora's capex (and opex) allowance for this non-network solution is consistent with the assumption that this network project will be required also. Our view is that the non-network solution will most-likely mean that a network solution will not be required in the next period. This matter will be discussed further in Section 5.5.2 on Aurora's non-network plans.*[25]

148. However, a general finding of Nuttall's analysis was that many of Aurora's augmentation capital expenditure programs would only be justified if they delivered efficiency benefits in the form of lower operating expenditure.

> *The efficiency benefit component covers the remaining capex where we consider that this must be justified based upon opex and reliability benefits. It is important to note that we are not advising that this capex is justifiable; rather, if the AER makes a capex allowance for this component, it needs to satisfy itself that there are appropriate adjustments to the opex and/or reliability targets to ensure that this capex component would result in net benefits.* (Page 54)

149. This is summarised at Table 12 on page 57 of the Nuttall Consulting report. On the basis of this analysis Nuttall Consulting advises the AER that:

> *The demand component we have determined represents a 50% reduction on the forecast proposed by Aurora. The efficiency benefit component represents an additional 36% of Aurora's proposed reinforcement capex. However, for the reasoning discussed above, the AER will need to decide whether an allowance for this efficiency benefit component is appropriate, and if so, whether appropriate adjustments to Aurora's opex forecast and reliability targets have been made.*

[25] Nuttall Consulting, Report, p 42.

150. In its draft decision the AER[26] explicitly made the adjustments to operating costs proposed by Nuttall Consulting. In doing so, the AER explicitly linked its approach back to the statistical benchmarking results:

> *The AER considers its findings are consistent with benchmarking results. For example, the large proportion of capex that should result in efficiency benefits explains why Aurora's proposed capex to address demand growth is much higher than that of the Victorian DNSPs.*

151. The nature of the logic used by the AER and their advisers demonstrates the importance of interactions between different types of expenditures. In the ENA's view it highlights the importance of engineering expertise being applied in the assessment of the specific type of expenditure proposed in order to appropriately account for those interactions.

152. This is something that, in the ENA's view, pure statistical benchmarking is unlikely to be able to achieve in the foreseeable future. However, as datasets and the understanding of the data improves it may be possible that these sorts of interactions could appropriately be taken into account .

7.4. Total operating expenditure

153. The AER has acknowledged the intrinsic difficulties associated with benchmarking aggregate operating expenditure. This issue was discussed in some detail in its recent Victorian electricity draft decision (numbered headings from the original).[27]

> **I.8 Limitations of benchmarking**
>
> *Benchmarking is a useful tool available to the AER to compare DNSPs. However benchmarking techniques require operating conditions to be accounted for so as to make firms more directly comparable.33 The limitations of benchmarking are frequently discussed in economic texts and were recently discussed in detail in the AER's recent decisions for South Australia and Queensland electricity distribution.[34]*
>
> *In most benchmarking models, where a firm appears less efficient than its peers, it will be unclear whether this difference is due to real inefficiency, data noise or a failure of the model to account for some firm-specific factor.35 In order to minimise this problem high quality data is needed. Some of the general limitations of benchmarking and associated possible sources of error are;[36]*

[26] AER, Aurora draft decision, pages 140 to 142.

[27] AER, *Draft decision: Victorian electricity distribution network service providers: Distribution determination 2011–2015*, Appendix I, pp. 78–80.

- *that the results obtained from the benchmarking are sensitive to the adopted method*
- *that individual efficiency estimates remain sensitive to the assumptions regarding the adopted approach and model specification*
- *errors in the assumptions of the technique used to normalise the data*
- *errors in the selection of measured inputs and outputs (in particular, failing to correctly include relevant inputs or outputs)*
- *errors in the measurement or aggregation of the inputs or outputs*
- *errors in the assumptions about the information that can be obtained from relative productivity information and how that information is best extracted.*

The AER notes the following specific limitations may affect comparisons based on the benchmarking undertaken for this reset:

- *the lumpiness of the capex programs*
- *differing licensing requirements which exist between the NEM jurisdictions*
- *differences in whether DNSPs buy or lease assets*
- *differences in balance dates*
- *variations in the characteristics of DNSPs (see I.8.1) and the age, size and maturity of their networks and the markets they serve*
- *capitalisation, cost allocation and other accounting policies, as well as regulated service classifications, are assumed to be the same across all DNSPs, and across regulatory control periods in the sample*
- *the sample includes a cross section of rural, urban and CBD DNSPs.*

For this review the AER has found limitations in the available data that may preclude properly accounting for these factors, especially when making comparisons of business performance between DNSPs in different jurisdictions.

I.8.1 Characteristics of Victorian DNSPs

There are differences between DNSPs within the NEM and within Victorian DNSPs. The AER notes and attempts to take into account these differences when benchmarking DNSPs - when the available data permits. The differences that exist between DNSPs include the following variable factors:

- *the geography of service areas*
- *customer density and usage characteristics*

- *climatic conditions, including the duration and intensity of heatwaves and storms*
- *the age, condition and structure of the networks*
- *specific jurisdictional obligations.*

154. Nonetheless the AER does attempt to perform benchmarking at the level of aggregate operating expenditure. However, these limitations inevitably lead to the AER to only use aggregate opex level statistical benchmarking as a 'scene setting' first step in its analysis. The ENA considers that this is appropriate.

155. The Productivity Commission may usefully review the nature of the analysis undertaken by the AER in, for example, Appendix B of the AER's recent draft decision for Aurora. This gives an indication of the difficulties of performing a sophisticated 'like for like' comparison at the aggregate level. It also provides a feel for the degree of discretion that would have to be exercised by the regulator in performing such an analysis – a degree of discretion that the ENA considers would be inappropriate if this analysis was the sole basis for determining efficient expenditures.

7.5. Vegetation management

156. The Productivity Commission's issues paper mentions the Australian Competition Tribunal's rejection of the AER's benchmarking of Powercor's vegetation management costs as a possible example of the difficulties in using benchmarking. It is worth noting the reasons given for the rejection of the AER's proposal was as follows

    (a) in relation to HBRA, compared with all of the other DNSPs, Powercor's less frequent cutting involves more aggressive cutting, which is more costly per span cut than more frequent light cutting. This illustrates the need for the AER, when comparing unit rates of one DNSP with one or more of the other DNSPs, to be careful to ensure that appropriate consideration is given to the differences between the networks and the work programs in place for achieving the clearance requirements according to the relevant regulations.

    (b) insofar as the insulated service line changes were concerned, it is apparent that there were vast differences in the frequency of cutting in SP AusNet's network compared with Powercor's network. Nuttall Consulting had placed considerable weight on SP AusNet's rates. In addition, there were substantial differences between the inclusions in the rate as between CitiPower and UED/JEN. The costliest lines, for example, were not in the unit rate because aspects of the costs were dealt with as capital (rather than opex). Furthermore, the AER did not

> *make allowance for inspection costs in applying the unit rates of other DNSPs.*[28]

157. In the ENA's view this is an example of the Rules working well to ensure that non-robust benchmarking is not used to set compensation for actual costs.

7.6. Mountain reports

158. Bruce Mountain has prepared two papers for the Energy Users Association Australia (EUAA):

- *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* (Mountain (2011)) published in May 2011;[29] and
- *Electricity Prices in Australia: an International Comparison* (Mountain (2012)) published in March 2012.[30]

Both provide strong examples of the dangers of drawing conclusions from uniformed, pure statistical benchmarking.

Mountain (2011)

159. Following a review of the expenditure allowances of distribution network service providers (DNSPs), Mountain (2011) concludes that regulatory failure and Government ownership are the major causes of recent price increases, rather than the well understood need for investment to replace aging assets and meet the requirements of rising peak demand. On this basis, Mountain makes a number of recommendations that, the paper argues, would raise productivity in this sector.

160. An assessment by NERA (Appendix B attached) of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs per connection and a reliance on inappropriate comparisons has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. Mountain's focus on ownership as the key distinction between DNSPs omits consideration of state-specific cost drivers. Identification of actual cost drivers is further hampered by Mountain's reliance on state averages rather than reviewing data on a DNSP specific basis.

161. Mountain begins by comparing revenue, capex and the value of the RAB per connection within each state, on a weighted average basis. The paper notes that growth in each of these ratios has been substantially higher for DNSPs in Queensland and NSW as opposed to South Australia and Victoria. On this basis, Mountain

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28 http://www.austlii.edu.au/au/cases/cth/ACompT/2012/1.html para 653

29 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.

30 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

concludes that the financial performance of government-owned DNSPs, being those in Queensland and NSW, is relatively poor compared to that of the privately-owned DNSPs, being those in South Australia and Victoria.

162. As explained by NERA, a comparison of these ratios is ill-suited to making conclusions regarding the relative efficiency of DNSPs. There are numerous reasons, besides relative efficiency, why DNSPs would have different levels of opex, capex and RAB per connection. These will include service quality standards, past expenditure decisions and the nature of the network, such as the mix between industrial and residential connections, network length, customer density, peak and average demand levels, the split between transmission and distribution networks, etc.

163. Furthermore, the use of averages for each state masks variations in costs between firms within a state. Such a loss of information makes it difficult to draw conclusions about the true causes of cost differences.

164. Mountain develops a composite scale variable (CSV) to assess the relative efficiency of the NSPs. This analysis, in essence, assumes that customer numbers and network length are the only drivers of DNSP costs. Because this analysis fails to account for the many other drivers of cost differences, it is impossible to accept it as a good indication of the relative efficiency of firms.

165. Mountain's comparison of the costs of NEM distributors to those in the Great Britain sheds very little light on the efficiency of the NEM distributors for a number of reasons.

- first, making international comparisons is difficult due to such factors as exchange rates, comparability of the costs, scope of businesses, etc.;
- second, there are many legitimate reasons prices will differ between DNSPs in different countries. For example:
  - o many differences in the nature of the networks being considered. For example, line lengths and peak versus average demand;
  - o distortions in the current prices due to past regulatory decisions; and
  - o differences in cost of inputs.

166. Mountain goes on to review of a number of potential cost drivers that may have been responsible for recent price increases. In our view, a number of shortcomings in this analysis makes it difficult to agree with Mountain that it is government ownership and the regulatory framework are the key drivers of price increases. Specifically Mountain dismisses:

- rising peak demand as a driver of investment by considering the growth in historic aggregate and average demand. However, networks must be configured to meet anticipated peak demand, not past average demand. Consideration of Figure 3.1 on page 14 of the NERA report at Appendix B leads to the opposite conclusions;

- the need to replace aging assets as a driver of investment by considering the average effective remaining life of assets. Mountain acknowledges that the profile of asset age is more important than the average remaining life but assumes that NSPs have similar asset age profiles making it possible to then simply compare the average. This is simply incorrect (see page 15 *et seq* of the Appendix B NERA report); and
- claims that there is an element of "catch-up" in investment due to past levels of under-investment largely on the basis of information regarding potential efficiency gains from 1982 to 1994, which is of highly questionable relevance.

Mountain (2012)

167. Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison* provides an international comparison of electricity retail prices. On the basis of this comparison, Mountain concludes that Australian prices are high and rising when compared to those in other countries

168. The paper was not submitted to the AEMC as part of its review of the AER and EURCC's Rule change proposals. The report also concerns *retail* prices rather than network charges and is further limited to *household* customers, ignoring the relative prices of industrial customers.

169. While of limited direct relevance, the paper demonstrates the dangers of drawing conclusions about productivity and prices based on aggregated data without making the appropriate adjustments. The NERA report at Appendix B explains *inter alia* that:

- Mountain has emphasised comparisons with international retail prices based on market exchange rates whereas Purchasing Power Parity (PPP) comparisons are arguably more appropriate — on a PPP basis, Australian prices are lower than those in Japan and the EU;
- Mountain has also used older data for other jurisdictions than that used for Australia, limiting the comparability; and
- other commentators have arrived at quite different conclusions from Mountain regarding Australia's retail electricity prices.

List of Appendices

Appendix A. NERA Economic Consulting Report - Analysis of Key Drivers of Network Price Changes

The attached report by NERA analyses the extent to which network price changes for both electricity transmission and distribution businesses in the current regulatory period have been the result of changes in the cost of capital and increases in forecast capital and operating allowances. The report examines the key drivers behind the increases and considers the extent to which they reflect changes in circumstances which have been recognised as legitimate by the AER, rather than indicating shortcomings with the current regulatory framework.

Appendix B. NERA Economic Consulting Report – Rising Electricity and Network Productivity: a Critique

Appendix C. Responses to Issues Paper questions

Appendix A

NERA Economic Consulting Report

Analysis of Key Drivers of Network Price Changes

NERA
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A report prepared for the ENA

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Contents

List of Tables

List of Figures

Executive Summary

The primary focus of this report is on analysing the extent to which network price changes for both electricity transmission and distribution network service providers (NSPs) in the current regulatory period have been the result of changes in the revenue requirements for NSPs arising from changes in WACC and increases in forecast capex and opex allowances. We have also identified the change in the NSPs' revenue requirement due to 'other factors', outside of the increase in WACC, capex and opex.

Further, we have examined the key drivers behind the increases in WACC and forecast capex and opex allowances, and considered the extent to which they reflect changes in circumstances which have been recognised as legitimate by the AER, rather than indicating shortcomings with the current regulatory framework. We note that NERA has prepared a separate report for the ENA covering the policy intent of the Chapter 6A Rules, and whether the AER's determinations under Chapter 6A are consistent with that policy intent.[1]

Specifically, this report is responding to the Australian Energy Market Commission (AEMC's) call in its Directions Paper in relation to the AER's Rule change proposal for further evidence 'on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges'.[2]

Our overall conclusion is that whilst increases in capex and opex allowances have been a key driver of recent increases in network charges across many NSPs, the increase in the allowed WACC has generally been more significant. The underlying reasons for the required increases in capex and opex vary across businesses and include factors such as increasing peak demand, replacement of aging assets and meeting environmental, safety and statutory obligations. Furthermore, both the increases in capex and opex allowances and the increase in the WACC have been driven by changes in external circumstances, which have been examined and acknowledged by the AER, rather than being a product of the Rules.

Methodology

This analysis addresses the impact of increases in the revenue requirements on network prices. It does not seek to address the impacts of forecast changes in customer total demand on network prices.

We have used the Post-Tax Revenue Model (PTRM) for each NSP to estimate the P_0 change that would have resulted if the AER's decision at its last determination had adopted:

1. the WACC allowed in the previous regulatory decision; or
2. the real forecast capital expenditure (capex) allowed in the previous regulatory decision; or
3. the real forecast operating expenditure (opex) allowed in the previous regulatory decision.

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1 NERA Economic Consulting, *Capital and Operating Expenditure – Response to AEMC Directions Paper*, April 2012.

2 AEMC, Directions Paper, p. 28.

For each NSP we have carried out three separate analyses, to identify the impact of each of the above three factors on the P_0 change.[3] We have also identified the residual change in P_0 due to 'other factors'.

Impact of the WACC in driving P_0 increases

The increase in the allowed WACC between regulatory periods has contributed significantly to the observed network price rise in almost all of the jurisdictions analysed. Only for the ACT was the change in the WACC found to have a minor impact on the overall change in real prices.

The increase in WACC is also significant in terms of the materiality of its impact on the overall increase in P_0. For example, in Queensland the change in WACC results in an 18% increase in P_0 for DNSPs (on a weighted average basis), out of the total 45% P_0 change. Similarly, in NSW the change in WACC results in an 12.8% increase in P_0 for DNSPs (on a weighted average basis), out of the total 49.3% P_0 change, whilst in South Australia the change in WACC accounts for a 14.1% increase in P_0 for ElectraNet, out of the total 33.9% P_0 change.

Our analysis of the key drivers of the increase in the WACC between regulatory periods has shown that the increase has been driven by an increase in the debt risk premium. The increase in the debt risk premium has been due to a change in market conditions (predominantly the impact of the global financial crisis), rather than a change in the benchmark credit ratings adopted. The increase in the WACC does not therefore reflect shortcomings in the regulatory framework.

Impact of increased capex allowance in driving network price increases

The increase in the capex allowance between periods has contributed significantly to the observed price rise in all jurisdictions analysed. Specifically, the increase in allowed capex between periods is found to represent at least 18% of the overall change in P_0 for all jurisdictions.

The impact of the increase in allowed capex is the most material in NSW and South Australia. The increase in forecast capex allowances in NSW results in a 16% and 14% increase in P_0 for DNSPs and TNSPs, respectively. In South Australia, the increase in capex allowance implies an increase of 10.6% in the P_0 for ETSA Utilities. Further, our analysis has found that changes in real costs are not a key driver of increases in capex allowances and have in fact had an offsetting impact, ie, the real cost of capex has gone down between this regulatory period and the last.

Our assessment indicates that the key drivers of the increase in capex allowances between regulatory periods differ across NSPs. However augmentation to meet peak demand growth, asset renewal/replacement and environmental, safety & statutory obligations (excluding

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3 The P_0 represents the change in real network prices, where the regulatory control mechanism for the NSP is a price cap, which is the case for most DNSPs. In the case of TNSPs, who are all subject to a revenue cap, and for those DNSPs subject to a revenue cap, the P_0 represents the increase in real revenue.

reliability) are categories of expenditure that have contributed substantively to the overall increase in capex allowance for a large number of DNSPs and TNSPs.

Moreover, our analysis indicates that in reviewing the proposed capex allowances, the AER and the engineering consultants it has commissioned, have recognised these external circumstances as being legitimate drivers of the allowed expenditure and the expenditure allowed as prudent and efficient.

Impact of increased opex allowance in driving P_0 increases

The increase in the allowed opex between periods has contributed significantly to the observed price rise in almost all jurisdictions analysed. Specifically, only for ElectraNet (South Australia) and SP AusNet transmission (Victoria) is the increase in opex allowance found to represent less than 10% of the overall change in P_0.

The impact of the increase in allowed opex is the most material for the DNSPs in NSW, South Australia and the ACT as well as for the TNSP in Tasmania. The increase in forecast opex allowance in the ACT results in an 18% increase in P_0 for ActewAGL. For the NSW DNSPs the increase in P_0 due to the higher opex allowance is 15.6% (on a weighted average basis), whilst for ETSA Utilities the increase is 10%. In Tasmania, Transend's increase in P_0 due to the increase in opex allowance alone would have been 10.6%.

Our assessment of the key drivers of the increase in opex allowances between regulatory periods has identified that real cost escalation has only contributed modestly to the increase in total opex (between 1.9% and 3.5% across all NSPs). In terms of other drivers, the increase in opex allowances reflects circumstances (eg, increased legislative obligations (including Feed-in Tariffs) and expansion of the capital base) which have been recognized as legitimate drivers of expenditure by the AER, and which have been reviewed by external consultants. Moreover, for four out of the five NSPs we reviewed in detail, the reduction made by the AER to the forecast opex exceeded that recommended by the independent consultants.

Impact of 'other' factors in driving P_0 increases

The contribution of other factors on the change in P_0 is less than the combined contribution of the changes in WACC, capex and opex. However the impact of other factors does remain a substantive component of the overall change in the P_0 for all jurisdictions, with the exception of the ACT. For the Victorian DNSPs, and for NSW transmission, changes in these other factors offset some of the impact of WACC, capex and opex, resulting in P_0 changes being below the level that they would otherwise have been.

The impact of other factors is the most material for the Queensland DNSPs and ElectraNet. Specifically, the impact of other factors in Queensland has resulted in a 15% increase in the P_0 for DNSPs (on a weighted average basis). For ElectraNet, the impact of other factors increased the P_0 by 10.3%.

The 'other factors' affecting the P_0 outcomes include increases in actual outturn capital expenditure in the previous regulatory period (rather than the capex allowance for future periods); revenue associated with the operation of the EBSS and differences between outturn and expected demand. Importantly, these factors reflect the legitimate outworkings of the regulatory arrangements, rather than shortcomings in particular regulatory rules.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) for the Energy Networks Association (ENA).

The primary focus of the analysis set out in this report is on analysing the extent to which network price changes for both electricity transmission and distribution businesses in the current regulatory period have been the result of changes in the revenue requirements for NSPs arising from changes in the Weighted Average Cost of Capital (WACC) allowed by the Australian Energy Regulator (AER), increases in forecast capital expenditure allowances and increases in forecast operating expenditure allowances. We have examined the key drivers behind the increases in each of these three factors, to identify the extent that these reflect changes in circumstances recognised as legitimate by the AER or whether they indicate shortcomings with the current regulatory framework.

Specifically, this report is responding to the Australian Energy Market Commission (AEMC's) call in its Directions Paper in relation to the AER's Rule change proposal for further evidence 'on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges'.[4] Our conclusion is that whilst increases in capex and opex allowances have been a key driver of recent increases in network charges across many NSPs, the increase in the allowed WACC has generally been more significant. Furthermore, both the increases in capex and opex allowances and the increase in the WACC have been driven by changes in external circumstances, which have been examined and acknowledged by the AER, rather than being a product of the Rules.

We note that NERA has prepared a separate report for the ENA covering the policy intent of the Chapter 6A Rules, and whether the AER's determinations under Chapter 6A are consistent with that policy intent.[5]

The remainder of this report is structured as follows:

- Section 2 summarises our approach to assessing the extent of the change in network prices/revenues arising as a result of changes in WACC, allowed capex and allowed opex.
- Section 3 sets out our findings in relation to the relative importance of each of these three factors in contributing to the overall increase in network prices/revenues, for each of the five National Electricity Market (NEM) jurisdictions, together with the extent of the change in network prices/revenues which is applicable to other factors. The results of this analysis for each individual network service provider (NSP) are set out in Appendix A.
- Section 4 then analyses the key factors underpinning the increase in the WACC in the current regulatory period for each NSP, and concludes that these factors reflect changes in market conditions, rather than shortcomings with the current Rules.
- Section 5 analysis the key drivers for the increase in capex allowances in the current regulatory period, particularly for those NSPs where the increase in capex allowance has

[4] AEMC, Directions Paper, p. 28.

[5] NERA Economic Consulting, *Capital and Operating Expenditure – Response to AEMC Directions Paper*, April 2012.

been a key driver of an overall substantive increase in their P_0. In each case we review what the NSP said in relation to these drivers in its regulatory submission to the AER, and the AER's responding determination.

- Section 6 presents the complementary analysis of the key drivers of the increase in opex allowances, for those NSPs where the increase in opex allowance has been a key driver of an overall substantial increase in network prices/revenues.

2. Methodology

This section sets out the approach we have adopted in calculating for each NSP the extent to which the change in real network prices/revenues in the current regulatory period has been the result of changes in WACC, capex and opex allowances.

2.1. P_0 Analysis

We have used the post-tax revenue model (PTRM) for each NSP to estimate the P_0 change that would have resulted if the AER's decision at its last determination had adopted:

1. the WACC allowed in the previous regulatory decision; or
2. the real forecast capital expenditure (capex) allowed in the previous regulatory decision;[6] or
3. the real forecast operating expenditure (opex) allowed in the previous regulatory decision.[7]

For each NSP we have carried out three separate analyses, to identify the impact of each of the above three factors on the P_0 change. The P_0 represents the change in real network prices, where the regulatory control mechanism for the NSP is a price cap, which is the case for most DNSPs.[8] In the case of TNSPs, who are all subject to a revenue cap, and for those DNSPs subject to a revenue cap, the P_0 represents the increase in real revenue.

We note that our analysis has considered the impact on P_0 of each factor in isolation, keeping the other two factors constant. As a consequence, the results of our analysis are not additive, and cannot be combined in order to determine the per cent contribution to the P_0 change made by each of the change in WACC, forecast capex and forecast opex. We consider this to be the most appropriate approach, as the identified contribution of each factor in an additive approach will depend upon the order in which the factors are considered. For example, the contribution of an increase in the WACC on the P_0 change will appear greater if the analysis first takes into account the increase in capex forecast, and then applies the increase in WACC to that higher forecast. Approaches which attempt to breakdown the overall P_0 into the contribution of each of the relevant factors therefore risk being misleading.[9]

[6] We note that where a previous regulator's decision did not provide an allowed capex profile (either in terms of expenditure type or timing) then we have assumed the same expenditure profile as in the current decision.

[7] We note that where a previous regulator's decision did not provide an allowed opex profile (in terms of timing) then we have assumed the same expenditure profile as in the current decision.

[8] The exceptions are the Queensland DNSPs, ie ENERGEX and Ergon, which are subject to a revenue cap.

[9] For example, the AER's analysis in Table 18.11 on p.817 of its Victorian DNSP final decision 'per cent contribution to 'P_0' is potentially misleading, as the relative per cent contribution of each factor depends on the order in which the factors have been considered in the analysis – see: AER, (2010), *Victorian Electricity Distribution Network Service Providers Distribution Determination 2011–2015*, Final Decision, October 2010, p. 817.

We have also calculated the residual impact of 'other factors' on the P_0 outcomes, over and above the combined impact of the change in WACC, capex forecasts and opex forecasts.[10] 'Other factors' encompass a variety of things, including the realignment of tariff revenue to costs in the final year of the previous regulatory period arising from:

- forecast smoothed revenue for the previous period differing from forecast building block costs;
- forecast operating costs for the previous period differing from actual operating costs;
- forecast capital expenditure for the previous period differing from actual capex; and
- for those NSPs subject to price cap regulation, differences between forecast and actual demand in the final year of the previous regulatory period.

'Other factors' affecting P_0 outcomes also include revenues associated with the operation of the Efficiency Benefit Sharing Schemes (EBSS) and other incentive schemes.

We have used the PTRM models as adopted by the AER in its Final Decision for each NSP (subject to these reflecting the outcome of any subsequent appeal to the Australian Competition Tribunal (Tribunal)), with the exception that for ElectraNet we have used the more recent PTRM model which incorporates the outcome of AER approval of contingent projects. We also note that for the Victorian NSPs the PTRM models used in our analysis do not reflect the outcome of the most recent Tribunal decision.

We have conducted this analysis for each of the distribution network service providers (DNSPs) and transmission network service providers (TNSPs) in the NEM, with the exception of Powerlink and Aurora, where the AER has yet to make a Final Determination.

2.2. Recalculation of the P_0 for each NSP

To quantify the effect of the above three variables on P_0, we have first recalculated the P_0 for each NSP on the basis of setting the X-factor in years 2 to 5 to zero (ie, prices are held constant in real terms after the first year). We have then calculated the P_0 that equalises the building block revenue requirements allowed in the AER's Final Decision[11] with the smoothed forecast revenue.

We have undertaken this recalculation of the P_0 for each NSP in order to be able to isolate the total network price/revenue change implied by the AER's determination into a single P_0 figure.[12] Note that the DNSPs are generally subject to a price cap and so the P_0 represents the change in real network prices from the end of the previous regulatory period to the first year of the current regulatory control period.[13] This approach makes the calculation of the

[10] We note that our analysis considers the combined impact of the increase in WACC, capex and opex forecasts, and then identifies the residual as being due to 'other factors'. Alternative approaches which first adjust for 'other factors' would result in different contributions being calculated for WACC, capex and opex.

[11] Or as amended by the later AER approval of a contingent project (in the case of ElectraNet) or the outcome of an appeal to the Tribunal.

[12] We note that this approach in recalculating P_0 accords with that adopted by the AER in its analysis of the 'per cent contribution to 'P_0' in Table 18.11 of the AER's Victorian DNSP final decision (p.817).

[13] The exceptions are the Queensland DNSPs (ie, Ergon and ENERGEX) which are currently regulated under a revenue cap.

contribution of the different factors to the P_0 change more straightforward, and allows for a clearer comparison of the results across NSPs.

The P_0 for each NSP for the current regulatory period resulting from this recalculation is set out in the following tables. In all cases, a negative P_0 represents an *increase* in network prices/revenues for that NSP.

Table 2.1
Recalculated P_0 - DNSPs

Business	Recalculated P_0
Ausgrid	-58.3%
Essential Energy	-49.7%
Ergon Energy	-47.5%
ENERGEX	-42.6%
ETSA Utilities	-36.4%
Endeavour Energy	-32.9%
ActewAGL	-22.7%
SP AusNet	-19.2%
Jemena	-11.0%
Powercor	-6.3%
United Energy	-5.6%
CitiPower	-1.4%

Source: NERA analysis.

Table 2.2
Recalculated P_0 - TNSPs

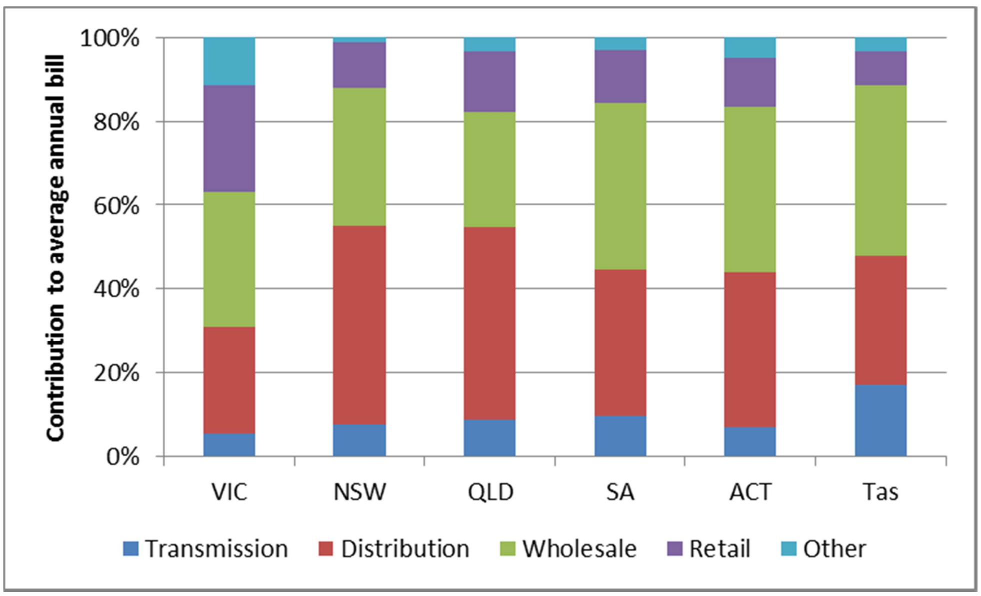
Business	Recalculated P_0
Ausgrid	-46.8%
ElectraNet	-33.9%
Transend	-32.5%
TransGrid	-18.2%
SP AusNet	-15.3%

Source: NERA analysis.

The above tables highlight that there have been some substantial real increases in network prices/revenues in the most recent round of regulatory determinations, with the recalculated P_0 for the DNSPs in NSW, the ACT, Queensland and South Australia reflecting increases in charges of over 20%. Similarly, in NSW (Ausgrid), South Australia and Tasmania, real increases in allowed transmission revenues have also exceeded 20%.

The analysis in this report is focused on the drivers behind the recent increase in network charges, rather than the increase in electricity prices faced by final consumers. Final consumer prices also include wholesale and retail costs, as well as other charges. The relative contribution of transmission and distribution network charges to end-use customer prices varies by jurisdiction, and is summarised in Figure 2.1.

Figure 2.1
Breakdown of Components of End-use Customer Prices, 2010/11



Source: NERA analysis using data in: AEMC, (2011), Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014, Final Report, 25 November 2011.

3. Key Drivers of Network Price Changes

This section sets out the results of our analysis of P_0 changes, comparing the impact of changes in WACC, capex allowances and opex allowances on the overall P_0 change, as well as highlighting the residual change in network prices/revenues due to other factors.

3.1. Impact on P_0 of the increase in WACC

3.1.1. Assumptions

We have calculated the change in P_0 for each NSP if the WACC parameters adopted by the AER in its most recent decision were instead substituted with the WACC parameters adopted in the previous regulatory determination (either by the ACCC (in the case of the TNSPs) or by each of the respective jurisdictional regulators (in the case of the DNSPs)).

Table 3.1 sets out the post-tax nominal WACC and gamma implied by the parameters adopted for the previous regulatory decision and the parameters adopted by the AER in the current decision.[14] Table 3.2 provides the equivalent summary for the TNSPs. Figures for each individual NSP are provided in Appendix B.

Table 3.1
Implied Change in WACC and Gamma - DNSPs

	Implied WACC from Previous Decision	**WACC[#] from Current Decision**
NSW – WACC	8.52%	10.07%
(Gamma)	(0.5)	(0.5)
VIC – WACC	8.61%	9.45% - 10.01%
(Gamma)	(0.5)	(0.5)
QLD – WACC	8.50%	9.77%
(Gamma)	(0.5)	(0.25)
SA – WACC	8.94%	9.81%
(Gamma)	(0.5)	(0.25)
ACT – WACC	8.53%	8.84%
(Gamma)	(0.5)	(0.5)

Source: NERA analysis.
[#] Includes the allowance for debt raising costs.

[14] Note that we have included debt raising costs in the presentation of the WACC for the current regulatory decisions, for comparability with the previous decisions.

Table 3.2
Implied Change in WACC and Gamma - TNSPs

	Implied WACC from Previous Decision	WACC# from Current Decision
NSW – WACC (Gamma)	8.92% (0.5)	10.07% - 10.10% (0.5)
VIC – WACC (Gamma)	8.24% (0.5)	9.76% (0.5)
Tasmania – WACC (Gamma)	8.80% (0.5)	10.06% (0.5)
SA – WACC (Gamma)	8.30% (0.5)	10.70% (0.65)

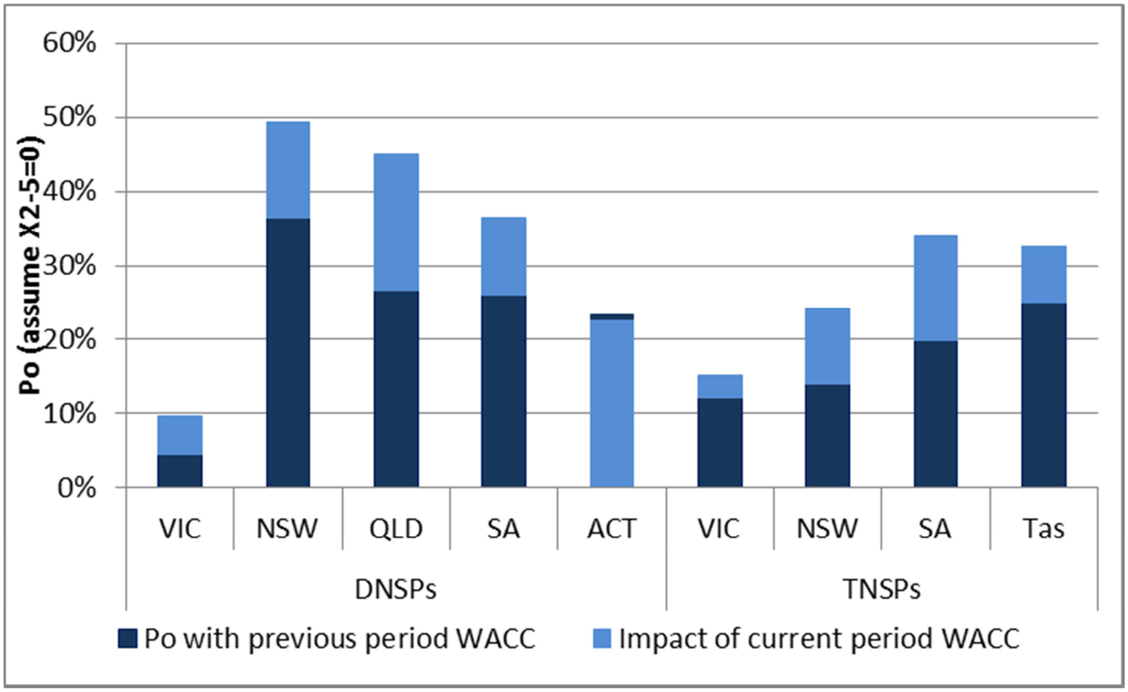
Source: NERA analysis.
\# *Includes the allowance for debt raising costs.*

3.1.2. Results

Figure 3.1 summarises the significance of the change in the WACC in terms of the increase in the P_0 in each jurisdiction. For each jurisdiction, the height of the light bar represents the total recalculated P_0 (ie, the values set out in the earlier Table 3.1 and Table 3.2),[15] whilst the height of the dark bar represents what the P_0 would have been had the previous WACC been retained. Appendix A provides the breakdown for each of the individual NSPs.

[15] For jurisdictions with more than one DNSP, the P_0 change shown represents the weighted average across all the DNSPs in that jurisdiction (weighted on the basis of the NPV of their respective total revenues).

Figure 3.1
Significance of the Increase in WACC in Driving P_0 Increases



Source: NERA analysis.

It is clear from Figure 3.1 that the increase in the allowed WACC between regulatory periods has contributed significantly to the observed P_0 rise in almost all of the jurisdictions analysed. Only for the ACT was the change in the WACC found to have a minor impact on the overall change in P_0 (and, indeed, to act to *reduce* the overall P_0).

The increase in WACC is also significant in terms of the materiality of its impact on the overall P_0 increases. For example, in Queensland the change in WACC results in an 18% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 27% to 45%. Similarly, in NSW the change in WACC results in an 12.8% increase in P_0 for DNSPs (on a weighted average basis), ie, an increase from 36% to 49%, whilst in South Australia the change in WACC accounts for a 14.1% increase in P_0 for ElectraNet, ie, an increase from 20% to 34%.

In section 4 we discuss the key drivers of the increase in the WACC between regulatory periods. Our conclusion in that section is that the increase in WACC has been driven by a change in market circumstances (specifically an increase in the measure of the debt risk premium), and does not reflect any shortcomings in the regulatory framework.

3.2. Impact on P_0 of the increase in capex allowances

3.2.1. Assumptions

We have calculated the change in P_0 for each NSP that would have resulted if the capital expenditure allowed by the AER for the current regulatory period were instead set to the same level (in real terms) as that allowed in each NSP's previous regulatory determination.

The tables below set out the total real forecast capex allowance by jurisdiction in the current and previous regulatory periods, for both DNSPs and TNSPs. In each case the values shown are in real terms, expressed in the dollars at the start of the current regulatory period for each NSP. Appendix B provides the details of the change in capex allowance for each NSP.

Table 3.3
Change in Real Capex Allowance – DNSPs ($m, real)

	Capex Allowance in Previous Period	Capex Allowance in Current Regulatory Period	% Increase
NSW	$5,122.2	$13,035.1	154%
VIC	$3,655.7	$4,702.7	29%
QLD	$7,380.0	$10,801.8	46%
SA	$844.4	$1,579.6	87%
ACT	$123.1	$275.4	124%

Source: NERA analysis using PTRMs provided by NSPs and forecast capex allowances publically available in the various regulatory decisions.

Table 3.4
Change in Real Capex Allowance - TNSPs ($m, real)

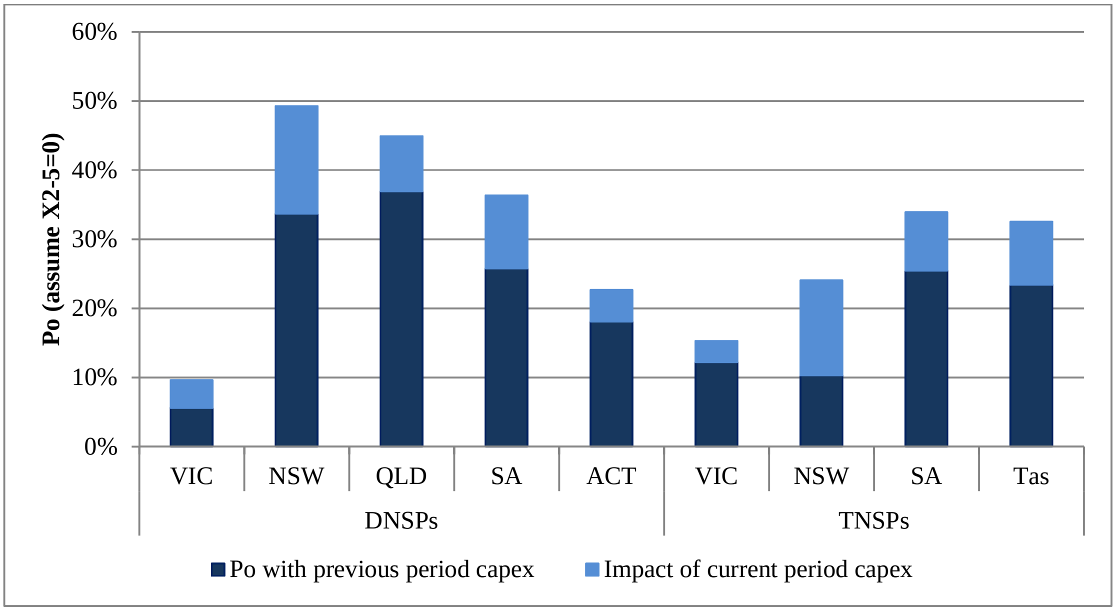
	Capex Allowance in Previous Period	Capex Allowance in Current Regulatory Period	% Increase
NSW	$1,646.7	$3,629.5	120%
VIC	$467.1	$769.6	65%
SA	$411.3	$788.9	92%
Tas	$338.1	$606.4	79%

Source: NERA analysis using PTRMs provided by NSPs and forecast capex allowances publically available in the various regulatory decisions.

3.2.2. Results

Figure 3.2 summarises the significance of the increase in forecast capex allowances in terms of the increase in the P_0 in each jurisdiction. Again, for each jurisdiction the height of the light bar represents the total recalculated P_0,[16] whilst the height of the dark bar represents what the P_0 would have been had the previous capex allowance been retained. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.2
Significance of Increase in Capex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the capex allowance between periods has contributed significantly to the observed P_0 rise in all jurisdictions analysed. Specifically, the increase in allowed capex between periods is found to be a significant factor and contributes at least 18% of the overall change in the P_0 for all jurisdictions.

The impact on P_0 of the increase in allowed capex is the most material in NSW and South Australia. The increase in forecast capex allowances in NSW results in a 16% and 14% increase in P_0 for DNSPs and TNSPs respectively (on a weighted average basis), ie, an increase from 34% to 49% for DNSPs and an increase from 10% to 24% for TNSPs. In South Australia, the increase in capex allowance implies an increase of 10.6% in the P_0 for the DNSP (ETSA Utilities), ie, an increase from 26% to 36%.

In section 5 we discuss the key drivers of the increase in capex allowances between regulatory periods. Our conclusion in that section is that the increases in capital expenditure allowances reflect circumstances (eg, increases in peak demand; asset condition) which have been recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

16 For jurisdictions with more than one DNSP, the P_0 change shown represents the weighted average across all the DNSPs in that jurisdiction (weighted on the basis of the NPV of their respective total revenues).

3.3. Impact on P_0 of the increase in opex allowances

3.3.1. Assumptions

We have calculated the change in P_0 for each NSP that would have resulted if the operating expenditure allowed by the AER for the current regulatory period were instead set to the same level (in real terms) as that allowed in each NSP's previous regulatory determination.

The tables below set out the total real forecast opex allowance by jurisdiction in the current and previous regulatory periods, for both DNSPs and TNSPs. In each case the values shown are in real terms, expressed in the dollars at the start of the current regulatory period for each NSP. Appendix B provides the details of the change in opex allowance for each NSP.

Table 3.5
Change in Real Opex Allowance – DNSPs ($m, real)

	Opex Allowance in Previous Period	Opex Allowance in Current Regulatory Period	% Increase
NSW	$4,191.3	$5,982.3	43%
VIC	$2,420.1	$2,700.0	12%
QLD	$2,943.9	$3,400.0	15%
SA	$762.4	$1,024.6	34%
ACT	$228.3	$339.6	49%

Source: NERA analysis using PTRMs provided by NSPs and forecast opex allowances publically available in the various regulatory decisions.

Table 3.6
Change in Real Opex Allowance – TNSPs ($m, real)

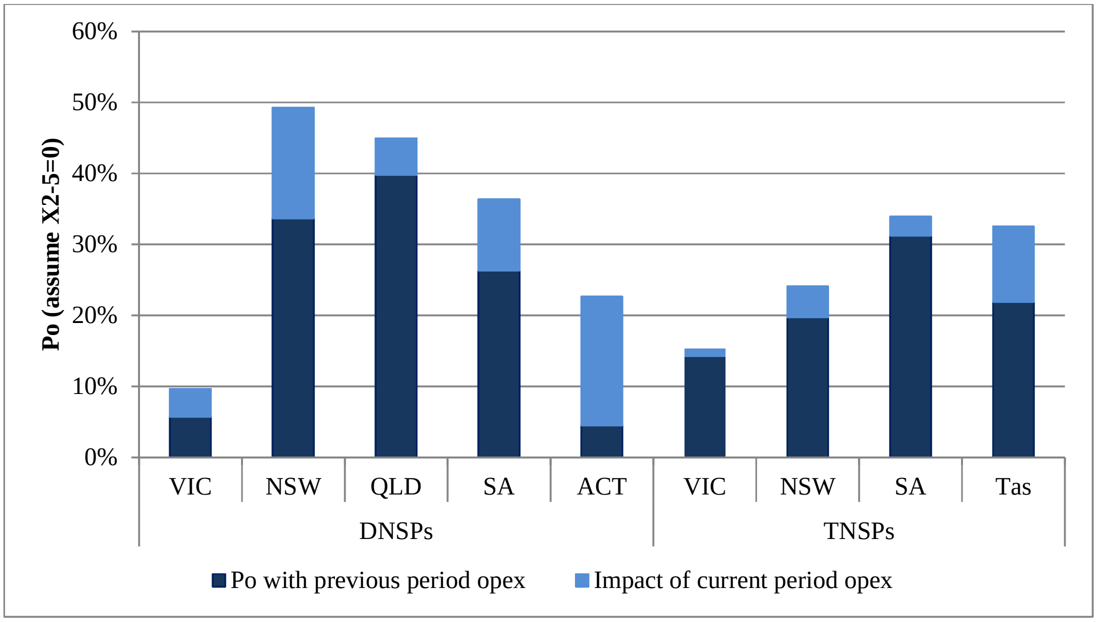
	Opex Allowance in Previous Period	Opex Allowance in Current Regulatory Period	% Increase
NSW	$824.4	$986.5	20%
VIC	$972.8	$1,003.5	3%
SA	$284.6	$310.2	9%
Tas	$176.8	$254.3	44%

Source: NERA analysis using PTRMs provided by NSPs and forecast opex allowances publically available in the various regulatory decisions.

3.3.2. Results

Figure 3.3 summarises the significance of the increase in forecast opex allowances in terms of the increase in the P_0 in each jurisdiction. Again, for each jurisdiction the height of the light bar represents the total recalculated P_0, whilst the height of the dark bar represents what the P_0 would have been had the previous opex allowance been retained. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.3
Significance of Increase in Opex Forecast in Driving P_0 Increases



Source: NERA analysis.

The increase in the allowed opex between periods has contributed significantly to the observed P_0 rise in almost all jurisdictions analysed. Specifically, only for ElectraNet (South Australia) and SP AusNet transmission (Victoria) is the increase in opex allowance found to represent less than 10% of the overall change in the P_0.

The impact of the increase in allowed opex is the most material for the DNSPs in NSW, South Australia and the ACT as well as for the TNSP in Tasmania. The increase in forecast opex allowance in the ACT results in an 18% increase in P_0 for ActewAGL, ie, an increase from 4% to 23%. For the NSW DNSPs the increase in P_0 due to the higher opex allowance is 15.6% (on a weighted average basis), ie, an increase from 34% to 49%, whilst for ETSA Utilities the increase is 10%, ie, an increase from 26% to 36%. In Tasmania, Transend's increase in P_0 due to the increase in opex allowance alone would have been 10.6%, ie, an increase from 22% to 33%.

In section 6 we discuss the key drivers of the increase in opex allowances between regulatory periods. Our conclusion in that section is that real cost escalation has only contributed modestly to the increase in total opex (ie, between 1.9% and 3.5% across all NSPs). In terms of other drivers, the increase in opex allowances reflects circumstances (eg, increased legislative obligations (including Feed-in Tariffs) and expansion of the NSP's capital base) which have been recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

3.4. Contribution of other factors to P_0 increases

3.4.1. Assumptions

The above analysis has focused on the impact of each of the increase in WACC, capex allowances and opex allowances on the P_0 increases for NSPs across the NEM. As discussed earlier, we have considered each of these factors in isolation.

We have also considered to what extent the P_0 increases have been driven by factors other than the change in WACC and expenditure allowances.

Specifically, we have calculated the change in P_0 for each NSP retaining the WACC, capex and opex allowed in the previous regulatory decision, in order to assess what effect *other factors* (ie, besides changes in allowed WACC, capex and opex) have had on the increase in the P_0.

3.4.2. Results

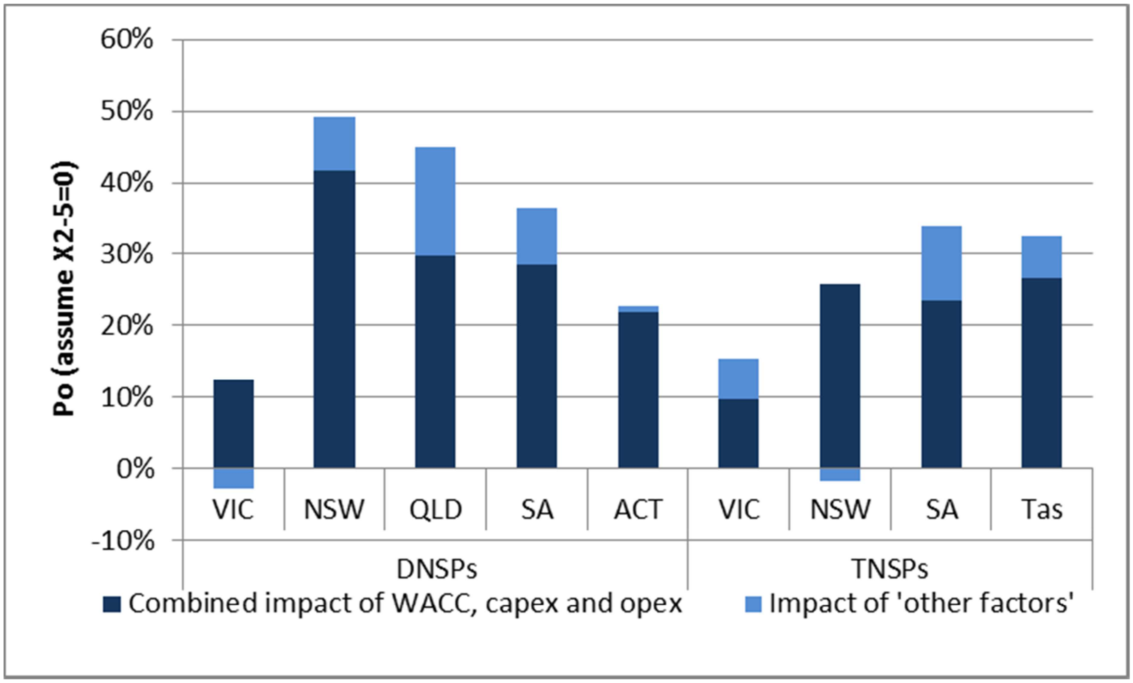
Figure 3.4 summarises the significance of other factors in terms of the increase in network prices/revenues in each jurisdiction. For each jurisdiction the height of the light bar represents the total recalculated P_0, whilst the dark portion of the bar represents the combined impact of the increases in the allowed WACC, capex and opex. Appendix A provides the breakdown for each of the individual NSPs.

Figure 3.4 shows that the contribution of other factors on the change in P_0 is less than the combined contribution of the changes in WACC, capex and opex. However the impact of other factors does remain a substantive component of the overall change in the P_0 for all jurisdictions, with the exception of the ACT.

In Victoria distribution and NSW transmission, changes in these other factors offset some of the impact of WACC, capex and opex, resulting in P_0 changes being below the level that they would otherwise have been.

The impact of other factors is the most material for the Queensland DNSPs and ElectraNet (South Australia). The impact of other factors in Queensland has resulted in a 15% increase in the P_0 for DNSPs (on a weighted average basis), ie, an increase from 30% to 45%. For ElectraNet, the impact of other factors increased the P_0 by 10.3%, ie, an increase from 24% to 34%.

Figure 3.4
Significance of Other Factors in Driving P_0 Increases



Source: NERA analysis.

The 'other factors' affecting the P_0 outcomes encompass a variety of things, including the realignment of tariff revenue to costs in the final year of the previous regulatory period arising from:

- forecast smoothed revenue for the previous period differing from forecast building block costs;
- forecast operating costs for the previous period differing from actual operating costs;
- forecast capital expenditure for the previous period differing from actual capex; and
- for those NSPs subject to price cap regulation, differences between forecast and actual demand in the final year of the previous regulatory period.

P_0 outcomes will also be affected by revenues associated with the operation of the Efficiency Benefit Sharing Schemes (EBSS) and other incentive schemes.

Importantly, these factors reflect the legitimate outworkings of the regulatory modelling, rather than any shortcomings in particular regulatory rules.

As part of the information gathering component of this assignment, we asked those NSPs for whom the impact of 'other factors' has a substantial impact on P_0 changes for information on the key components of these 'other factors'.

ENERGEX advised us that the following 'other' factors help explain its P_0 increase in the current regulatory period (noting that the first two are likely to account for the majority of the gap):

- In the previous regulatory control period (ie, 2004/5-2009/10), ENERGEX spent above its capex allowance, primarily to address compliance with obligations arising from the Queensland Government's Electricity Distribution Service Delivery (EDSD) review and to meet demand growth on its network. This contributed to a higher starting Regulatory Asset Base (RAB) for the current regulatory period;
- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER; and
- In the previous regulatory control period (2005-06 to 2009-10), ENERGEX's revenue was reduced to account for over-recoveries, adjustments to asset lives and opex carry forward from the 2001-02 to 2004-05 control period. These adjustments totalled $234 million and understate the efficient costs in the previous regulatory control period. In addition, the 2009-10 revenue included a downward adjustment of approximately $20.4 million for over recovery in 2007-08 which further understates the starting revenue and overstates the P_0

Ergon Energy advised us that the following 'other' factors help explain its P_0 increase between periods:[17]

- In the 2005-10 regulatory control period, Ergon Energy spent above its capex allowance, primarily to address customer and demand growth on its network. This contributed to a higher starting RAB for the current regulatory period;
- The tax allowance component under the Queensland Competition Authority's building block approach was based on actual tax paid, which is substantially lower than the assumed benchmark tax costs adopted by the AER;
- There was a carry forward amount from the previous period of $10.7 million ($2009-10) for accelerated depreciation due to Cyclone Larry, which further increased the allowed revenue in the first year of the current period; and
- The starting point of the 2009-10 revenue included a net over-recovery adjustment of approximately $9.3 million for revenue over recovery, cost pass through for Cyclone Larry and exclusion of excluded distribution services revenue, which would understate the starting revenue and overstate the overall P_0.

ElectraNet advised us that the following 'other' factors help explain its P_0 increase between this period and the last:[18]

- $21 million extra for capitalised equity raising costs - equity raising costs in the previous regulatory period were provided for by the ACCC as an allowance in perpetuity and the AER converted this into an amount capitalised in the RAB as part of the most recent decision;[19]
- $29 million for easement compensation costs;

[17] Similar to ENERGEX, Ergon Energy noted that the first two are likely to account for the majority of the gap.

[18] Note all figures are provided in $2007/08.

[19] AER, (2008), *ElectraNet Transmission Determination 2008–09 to 2012–13*, Final Decision, 11 April 2008, p. ix.

- A further $46.6 million for easement transaction or acquisition costs, granted as a result of merits review; and
- $17 million for readmission of optimised assets.

4. Drivers of the Increase in WACC

From our analysis of the drivers of the change in P_0, it is evident that the increase in the WACC between regulatory periods is a material driver of the change in real network prices/revenues.

We have undertaken further analysis to identify the key drivers of the increase in the WACC.

4.1. Methodology

The current return on assets for all NSPs is set by reference a nominal 'vanilla' post-tax WACC which is defined by the following formula:[20]

$$WACC = k_e \frac{E}{D+E} + k_d \frac{D}{D+E}$$

Where:

k_e is the nominal return on equity, determined by a domestic Sharpe-Lintner capital asset model (CAPM), ie:

$$k_e = r_f + \beta_e \times (r_m - r_f)$$

where

r_f is the nominal risk free rate;

β_e is the equity beta; and

$(r_m - r_f)$ is the domestic market risk premium;

k_d is the nominal cost of debt, as observed from observable domestic corporate bond performance, ie:

$$k_d = r_f + DRP$$

DRP is the nominal debt risk premium, ie, the difference between the nominal risk free rate and the yield on the benchmark corporate debt;

$\frac{D}{D+E}$ is the debt to value ratio of a benchmark efficient business; and

$\frac{E}{D+E}$ is the equity to value ratio of a benchmark efficient business.

For TNSPs, previous determinations applied a similar nominal 'vanilla' post-tax WACC. The process of comparing the current and previous allowed WACCs is therefore straight

[20] Clauses 6.5.2(b) and 6A.6.2(b) of the NER.

forward. Table 4.2, sets out the WACC applied to TNSPs in the current and immediately preceding determination.[21]

For DNSPs, the comparison is complicated by the fact that previous jurisdictional state regulators determined revenues on the basis of a variety of WACC definitions. For DNSPs in Queensland, South Australia, the ACT and Tasmania, we have used the constituent WACC parameters used in the previous state determinations in order to calculate a nominal 'vanilla' post-tax WACC.

However, in Victoria the Essential Services Commission (ESC) set a real 'vanilla' post-tax WACC and so all WACC parameters were defined in real terms. To estimate a comparable nominal 'vanilla' post-tax WACC, we converted the real parameter values to nominal values, using the Fisher equation and the ESC's forecast of inflation.[22]

The previous rate of return applied to the NSW DNSPs was a real pre-tax WACC of 6.70 per cent.[23] However, in arriving at this point estimate, the Independent Pricing and Regulatory Authority (IPART) assessed a plausible range for some WACC parameters. To back-solve the constituent point estimates of each WACC parameters consistent with IPART's 2004 actual determination of 6.70 per cent, we have generally taken the mid-point of the identified range. The exception to this rule was the equity beta, where we employed the excel solver function to ensure that the real pre-tax WACC matched the point estimate determined by IPART. Table 4.1 sets out the range specified by IPART in its final decision as well as the point estimates assumed by NERA.

Table 4.2 and Table 4.3 below set out the WACC applied to TNSPs and DNSPs in each jurisdiction in the current and immediately preceding determinations.

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21 Note that Powerlink has been excluded because the AER has only recently released its draft determination.

22 The Fisher equation, is specified by the following formula:

$Nom = \frac{1+real}{1+\rho} - 1$ where, ρ is the inflation rate expected by the ESC in its 2005 decision, ie, 2.56%.

23 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09: Final Report*, June 2004, p. 218.

Table 4.1
IPART's 2004 Regulatory WACC Decision

Parameter	IPART specified range Low	IPART specified range High	NERA estimate Point
Nominal risk free rate (06/05/04)	5.90%	5.90%	5.90%
Inflation	2.50%	2.50%	2.50%
Real risk free rate (06/05/04)	3.30%	3.30%	3.30%
Market risk premium	5%	6%	5.50%
Debt margin 0.9%-1.1%	0.90%	1.10%	1.00%
Allowance for debt raising costs	0.125%	0.125%	0.125%
Debt to total assets	60.00%	60.00%	60.00%
Dividend imputation factor (gamma)	50.00%	50.00%	50.00%
Tax rate	30.00%	30.00%	30.00%
Equity beta	0.78	1.11	0.918
Cost of equity (nominal post-tax)	9.80%	12.56%	10.95%
Cost of debt (nominal pre-tax)	6.93%	7.13%	7.03%
WACC (nominal post-tax)	6.14%	7.13%	6.56%
WACC (real pre-tax)	6.11%	7.50%	6.70%

Source: NERA analysis and IPART's 2004 NSW DNSP decision, page 218.

Table 4.2
TNSP Regulatory WACC Decisions

	Ausgrid		ElectraNet		Transend		TransGrid		SP AusNet	
	Previous	Current*	Previous	Current*	Previous	Current*	Previous	Current*	Previous	Current*
Risk free rate	*5.98%*	5.82%	5.17%	6.20%	5.86%	5.80%	*5.98%*	5.86%	6.09%	*5.12%*
Forecast inflation	*2.49%*	2.47%	2.07%	2.63%	2.32%	2.47%	*2.49%*	2.47%	2.59%	*2.04%*
Debt risk premium	*0.90%*	3.08%	1.22%	3.50%	1.02%	3.10%	*0.90%*	3.07%	2.11%	*1.20%*
Equity risk premium (β_e*MRP)	*6.00%*	6.00%	6.00%	6.00%	6.00%	6.00%	*6.00%*	6.00%	6.00%	*6.00%*
Gearing (D/V)	*60.00%*	60.00%	60.00%	60.00%	60.00%	60.00%	*60.00%*	60.00%	60.00%	*60.00%*
Return on debt	6.88%	8.90%	6.39%	9.70%	6.88%	8.89%	6.88%	8.93%	8.20%	6.32%
Return on equity	11.98%	11.82%	11.17%	12.20%	11.86%	11.80%	11.98%	11.86%	12.09%	11.12%
Nominal vanilla post-tax WACC	**8.92%**	**10.07%**	**8.30%**	**10.70%**	**8.87%**	**10.06%**	**8.92%**	**10.10%**	**9.76%**	**8.24%**
Real vanilla post-tax WACC[#]	6.43%	7.59%	6.23%	8.07%	6.55%	7.58%	6.43%	7.62%	7.17%	6.20%
Gamma	*0.5*	0.5	*0.5*	0.65	*0.5*	0.65	*0.5*	0.5	0.5	*0.5*

Source: NERA analysis of the WACC publically available in the various regulatory decisions.
** The current and previous WACC as determined by the AER has been adjusted to incorporate the allowed debt raising costs into the debt risk premium.*
[#] The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

Table 4.3
DNSP Regulatory WACC Decisions

	NSW		Victoria		Queensland		South Australia		ACT	
	Previous	**Current***	**Previous**	**Current***	**Previous**	**Current***	**Previous**	**Current***	**Previous**	**Current***
Risk free rate	5.90%	5.82%	5.27%	5.08%-5.65%	5.61%	5.64%	5.80%	5.89%	5.62%	4.29%
Forecast inflation	2.50%	2.47%	2.64%	2.57%	1.22%	2.52%	2.44%	2.52%	2.17%	2.47%
Debt risk premium	1.00%	3.08%	1.46%	3.80%-4.14%	2.76%	3.42%	1.64%	3.07%	1.25%	3.59%
Equity risk premium (β_e*MRP)	5.05%	6.00%	6.15%	5.20%	5.40%	5.20%	5.40%	5.20%	5.40%	6.00%
Gearing (D/V)	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
Return on debt	6.90%	8.90%	6.73%	8.90%-9.44%	6.83%	9.06%	7.44%	8.96%	6.87%	7.88%
Return on equity	10.95%	11.82%	11.42%	10.28%-10.85%	11.01%	10.84%	11.20%	11.09%	11.02%	10.29%
Nominal vanilla post-tax WACC	**8.52%**	**10.07%**	**8.61%**	**9.45%-10.01%**	**8.50%**	**9.77%**	**8.94%**	**9.81%**	**8.53%**	**8.84%**
Real vanilla post-tax WACC#	6.02%	7.60%	5.97%	6.88%-7.43%	5.74%	7.25%	6.50%	7.29%	6.36%	6.37%
Gamma	0.5	0.5	0.5	0.5	0.5	0.25	0.5	0.25	0.5	0.5

Source: NERA analysis of the WACC publically available in the various regulatory decisions.
** The current and previous WACC as determined by the AER has been adjusted to incorporate the allowed debt raising costs into the debt risk premium.*
 # The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

4.2. Results

The results of the analysis described above are set out in Table 4.6 (for DNSPs) and Table 4.7 (for TNSPs).

It is clear from these tables that the increase in the real WACC between regulatory periods is predominantly due to a higher debt risk premium (DRP). This finding is consistent across all DNSPs and TNSPs.

The Tribunal decision in 2011 to lower the value of gamma to 0.25[24] also has a significant impact on the P_0 calculation for those affected NSPs (ie, ETSA Utilities, ENERGEX and Ergon). However we note that the Queensland DNSPs have not been permitted to pass through the implied change in revenues resulting from the Tribunal decision, and hence the change in gamma is not a driver of the observed real network price change for these NSPs.

4.2.1. Increase in the DRP

Given its importance in driving the increase in the WACC, we have further considered the drivers behind the increase in the DRP between regulatory periods. Importantly, the DRP is affected by both the decision as to the appropriate benchmark to adopt for long term debt, and the observed market value associated with that benchmark.

The AER has adopted a benchmark for Australian corporate debt with a BBB+ credit rating and a 10 year term for maturity in all of its determinations, for both DNSPs and TNSPs. Furthermore, the AER concluded that this was the appropriate benchmark to adopt in its 2009 Statement of Regulatory Intent (SORI),[25] reflecting the evidence available at that time.

The tables below set out the benchmarks adopted in determining the DRP by the relevant regulator at the time of each NSP's previous regulatory determination, ie prior to the determination undertaken by the AER.

24 Application by ENERGEX Limited (Gamma) (No 5) [2011] ACompT 9, 12 May 2011

25 AER (2009), Electricity transmission and distribution network service providers, Statement of the revised WACC parameters (transmission), Statement of regulatory intent on the revised WACC parameters (distribution).

Table 4.4
Benchmark Adopted for Determining the DRP - DNSPs

Business	Increase in DRP	Previous benchmark	Current benchmark
Ausgrid	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
Essential Energy	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
Ergon Energy	220 basis points	BBB+, 10 yr	BBB+, 10 yr
ENERGEX	220 basis points	BBB+, 10 yr	BBB+, 10 yr
ETSA Utilities	143 basis points	BBB+, 10 yr	BBB+, 10 yr
Endeavour Energy	208 basis points	BBB+ to BBB, 10 yr	BBB+, 10 yr
ActewAGL	234 basis points	BBB+, 10 yr	BBB+, 10 yr
SP AusNet	268 basis points	BBB+, 10 yr	BBB+, 10 yr
Jemena	234 basis points	BBB+, 10 yr	BBB+, 10 yr
Powercor	237 basis points	BBB+, 10 yr	BBB+, 10 yr
United Energy	237 basis points	BBB+, 10 yr	BBB+, 10 yr
CitiPower	237 basis points	BBB+, 10 yr	BBB+, 10 yr

Source: NERA analysis using publically available regulatory decisions.

Table 4.5
Benchmark Adopted for Determining the DRP - TNSPs

Business	Increase in DRP	Previous benchmark	Current benchmark
Ausgrid	218 basis points	A, 10 yr	BBB+, 10 yr
ElectraNet	228 basis points	A, 10 yr	BBB+, 10 yr
Transend	210 basis points	A,5.5 yr	BBB+, 10 yr
TransGrid	217 basis points	A, 10 yr	BBB+, 10 yr
SP AusNet	91 basis points	A, 5 yr	BBB+, 10 yr

Source: NERA analysis using publically available regulatory decisions.

We note that for DNSPs, the benchmark credit rating adopted by the AER in the current regulatory period (ie, BBB+) is the same as, or slightly higher, than the benchmark credit rating adopted by the previous jurisdictional regulators at the time of the earlier regulatory decisions, whilst a 10-year term has been assumed in both cases. This implies that, absent any change in market conditions, the DRP estimated by the AER for the DNSPs in the current period would have been the same as or *below*[26] the DRP estimated in the previous period. The observed increase in the DRP for DNSPs is therefore solely due to changes in market conditions (predominantly the impact of the global financial crisis), leading to increases in the measurement of the DRP, rather than reflecting any change in the provisions in the Rules.

For the TNSPs, the AER benchmark (again, BBB+, 10 year) has changed from that applied in the previous regulatory periods (where a benchmark credit rating of A was adopted for all TNSPs). However the change in the benchmark credit rating was determined by the AER as appropriate in its 2009 SORI. The AER was not subject to any restrictions in its choice of benchmark credit rating in its review. Therefore, again, the change in DRP for the TNSPs, which has driven the increase in the WACC in the current regulatory period and, in turn, has had a substantive impact on real network revenues, does not reflect any shortcomings with the current regulatory arrangements.

4.2.2. Gamma

In 2011, the Tribunal[27] determined that the value of gamma (used to calculate the compensation for tax) should be set to 0.25, rather than 0.65 as determined by the AER.

The Tribunal's decision to lower the value of gamma has had a significant impact on revenues in the current regulatory period:

- ETSA Utilities – increase in tax compensation of \$162.2m (ie, which in itself leads to a P_0 price increase by 5.8%)
- ENERGEX – increase in tax compensation of \$189.5m (ie, which in itself leads to a P_0 revenue increase by 3.7%)
- Ergon – increase in tax compensation of \$131.5m (ie, which in itself leads to a P_0 revenue increase by 2.8%)

We have not incorporated the impact of the Tribunal's decision on the P_0 for the Victorian DNSPs given an updated PTRM is not yet available.

As noted above, Ergon and ENERGEX have not been permitted in practice by their shareholder (the Queensland government) to pass through the implied change in revenue for 2011-12 resulting from the Tribunal decision, and hence the change in gamma is not a driver of the *observed* real network price change for those NSPs.

The Tribunal's decision to lower the value of gamma reflects the outcome of its deliberations, rather than indicating a shortcoming with the regulatory framework.

[26] Since where a higher benchmark credit rating has adopted by the AER, this would imply a lower cost of debt, all else equal.

[27] Application by ENERGEX Limited (Gamma) (No 5) [2011] ACompT 9, 12 May 2011

Table 4.6 Analysis of the Drivers for the Change in WACC – DNSPs

DNSPs	Victoria					NSW			Queensland		ACT	SA
	Citipower	Powercor	SP AusNet	Jemena	United Energy	Ausgrid	Endeavour	Essential Energy	ENERGEX	Ergon	ActewAGL	ETSA Utilities
Real WACC: Current Decision#	6.88%	6.88%	7.13%	7.43%	6.88%	7.60%	7.60%	7.60%	7.25%	7.25%	6.37%	7.29%
Real WACC: Previous Decision#	5.97%	5.97%	5.97%	5.97%	5.97%	6.02%	6.02%	6.02%	5.74%	5.74%	6.36%	6.50%
Change basis points	91	91	116	146	91	158	158	158	151	151	1	79
Percentage increase in WACC	15.3%	15.3%	19.5%	24.5%	15.3%	26.2%	26.2%	26.2%	26.3%	26.3%	0.1	12.1%
Contribution to change in WACC												
Risk free rate	-19	-19	-13	38	-19	-8	-8	-8	3	3	-133	9
Debt risk premium	142	142	161	140	142	125	125	125	132	132	140	86
Equity premium	-38	-38	-38	-38	-38	38	38	38	-8	-8	24	-8
Inflation	7	7	7	7	7	3	3	3	24	24	-30	-8
Tax (additional Revenue)	0	0	0	0	0	0	0	0	\$203m (P_0 3.7%)	\$142.9m (P_0 2.8%)	0	\$149.4m (P_0 5.8%)

The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

Table 4.7 Analysis of the Drivers for the Change in WACC – TNSPs

TNSPs	SP AusNet	TransGrid	Energy Australia	ElectraNet	Transend
Real WACC: Current Decision#	7.17%	7.62%	7.59%	8.07%	7.58%
Real WACC: Previous Decision#	6.20%	6.48%	6.48%	6.23%	6.55%
Change basis points	97	113	109	184	103
Percentage increase in WACC	15.7%	17.4%	16.9%	29.5%	13.6%
Contribution to change in WACC					
Risk free rate	97	-12	-16	103	-6
Debt risk premium	55	125	125	137	131
Equity premium	0	0	0	0	5
Inflation	-55	2	2	-56	-15
Tax (additional Revenue)	0	0	0	-$3.0m	0

 # The Fisher equation has not been used to calculate the real vanilla post tax WACC, instead it is equal to the nominal WACC less the forecast inflation (which is a better reflection of the impact of the WACC on revenues).

5. Drivers of the Increase in Capex Allowances

The analysis in section 3.2 highlights that the increase in capex allowances in the current regulatory period compared to the previous regulatory period has had a substantive impact on the P_0 increases in the current period.

The next stage of our analysis has been to identify the drivers behind the increase in capex allowances. We first assess how much of the increase in the allowances are due to real cost escalation. We then analyse the other key drivers of the increase.

5.1. Real cost escalation

In order to estimate how much of the change in capex allowances is due to real cost escalation, we have used real cost indices commissioned by ENA from Sinclair Knight Merz (SKM). These indices act as a proxy for the real cost escalators adopted by the AER and the previous jurisdictional regulators in their regulatory decisions. Information on the actual real cost escalation factors adopted by the previous jurisdictional regulators is not available from public sources. For the purpose of this exercise, we consider that the escalators developed by SKM are a reasonable proxy for the escalators applied in the regulatory decisions, whilst recognising that the actual escalation factors adopted will have differed somewhat from these values.

The AER is not constrained under the Rules in substituting its own real cost escalation indices. Indeed, we note that the AER has chosen to substitute its own real cost escalators in all of its final determinations for each of the DNSPs and TNSPs.[28] As a consequence, any change in network charges due to the impact of real cost escalation on capex allowances does not indicate a shortcoming in the operation of the Rules.

SKM has modelled the changing price of equipment and project costs through combining forecast movements in the price of input components, with ‘weightings’ for the relative contribution of each component to final equipment/project costs. Specifically, SKM has undertaken this exercise for a ‘typical’ transmission and distribution network capex and opex program to derive an overall capex and opex escalator for each sector. The real cost indices developed by SKM are reproduced in Appendix C.

Table 5.1 sets out the percentage change in the real capex allowance between the current and previous regulatory periods accounting for changes in real costs of capex, for each DNSP.

[28] For example, the AER reduced Ausgrid’s total forecast distribution capex by $373.3 million ($m, 2008-09) to reflect its own real cost escalators in the final decision (see: AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 144). Similarly, the AER reduced Transend’s total forecast distribution capex by $63.1 million ($m, 2008-09) to reflect its own real cost escalators in the final decision (see: AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 65).

Table 5.1
Change in Capex Allowance Due to Real Cost Escalation - DNSPs

Business	Change in real capex
Ausgrid	-6.3%
Essential Energy	-6.3%
ActewAGL	-6.2%
Endeavour Energy	-6.1%
ENERGEX	-5.3%
Ergon Energy	-5.1%
ETSA Utilities	-5.0%
United Energy	-4.6%
CitiPower	-4.5%
Powercor	-4.4%
SP AusNet	-4.4%
Jemena	-4.0%

Table 5.2 provides the same breakdown for TNSPs.

Table 5.2
Change in Capex Allowance Due to Real Cost Escalation - TNSPs

Business	Change in real capex
Ausgrid	-6.2%
ElectraNet	-4.0%
Transend	-4.5%
TransGrid	-6.1%
SP AusNet	-1.1%

It is evident from the above that changes in real costs have not been a key driver of the increase in the capex allowance for NSPs in the most recent regulatory period. In fact, real costs for capex have *fallen* between the current and previous regulatory periods, implying that real costs have had a negative impact on the increase in the capex allowance (ie, have resulted in capex allowances being lower in real terms than they otherwise would have been).

This result is driven by the fact that the demand for many of the inputs used by NSPs slowed significantly following the onset of the global financial crisis in 2008. Put another way, the previous regulatory period for all businesses coincided (mostly) with times of high prices for the inputs used by DNSPs and TNSPs, while the current regulatory period incorporates much lower observations/expectations regarding prices for inputs.

This is evidenced in the real cost escalators provided by SKM, whereby the real cost of capex for both DNSPs and TNSPs dropped off significantly, following a peak in 2008. Figure 5.1 below illustrates this reduction in the real cost of capex for DNSPs as well as how it coincides with the last two regulatory periods (using the NSW DNSPs as an illustration, however, note that the other DNSPs have regulatory periods that are within one or two years of the NSW DNSPs).

Figure 5.1
SKM's Cumulative Real Cost Escalation of Capex – DNSPs, (July 2003 = 1.0)

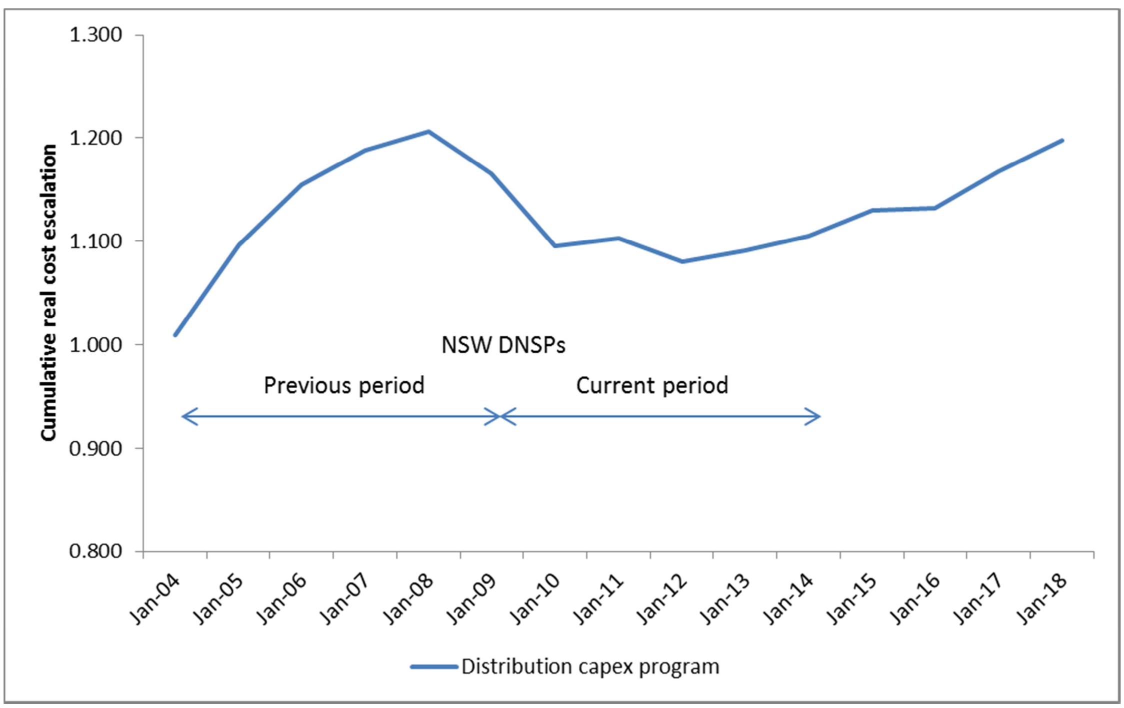
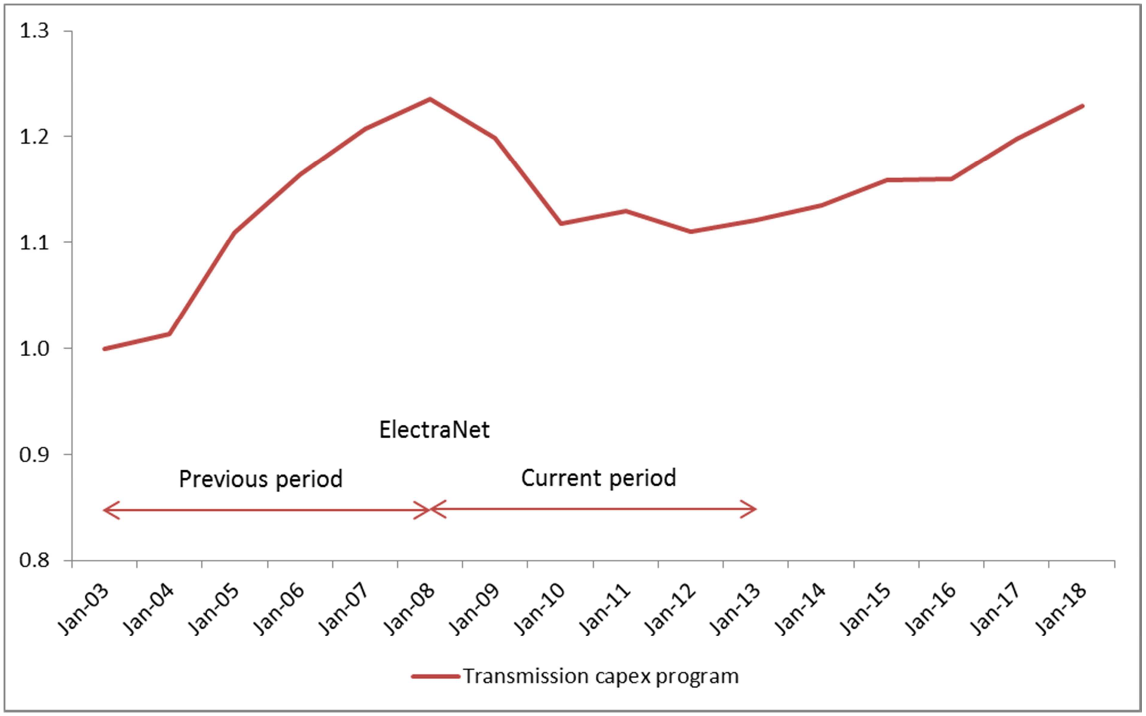


Figure 5.2 illustrates the reduction in the real cost of capex for TNSPs following the global financial crisis estimated by SKM, as well as how it coincides with the last two regulatory periods (using ElectraNet as an illustration, however, note that the other TNSPs have regulatory periods that are within one or two years of ElectraNet's).

Figure 5.2
SKM's Cumulative Real Cost Escalation of Capex – TNSPs, (July 2003 = 1.0)



5.2. Key drivers of the increase in capex allowances

In order to identify the key drivers of the increase in capex forecasts, NERA has facilitated completion of a survey from all DNSPs and TNSPs in the NEM. As part of this survey, the NSPs were asked to complete a template which included a breakdown of the capex allowance in the current and previous regulatory periods into key component categories.

For both TNSPs and DNSPs the following eight categories of capital expenditure were identified: (i) asset renewal/replacement; (ii) augmentation to meet peak demand growth; (iii) quality, reliability and security of supply enhancement; (iv) new customer connections (excluding customer contributions); (v) environmental, safety and statutory obligations (excluding reliability); (vi) SCADA and network control; (vii) non-network assets; and (viii) other.

Table 5.3 and Table 5.4 identify those categories of capex which have made the greatest contribution (in real $m terms) to the overall increase in the capex allowance for each DNSP and TNSP (respectively). For each NSP we have highlighted those categories of capex that have contributed the most to the increase. Appendix B provides further information in relation to each NSP.

It is evident from the tables that the key drivers of the increase in the capex allowance differ across NSPs. However augmentation to meet peak demand growth, asset renewal/replacement, environmental, safety and statutory obligations and new customer connections are categories of expenditure that have contributed substantively to the overall increase in capex allowance for a large number of DNSPs and TNSPs.

In the case of augmentation to meet peak demand growth, we note that it is increases in peak demand at a particular feeder level which are the key driver of network capex, rather than the system-wide increase in peak demand. This is particularly the case for networks which have a wide geographic spread, and where different parts of the network are facing different peak demand growth conditions (eg, due to the different composition of load in each area).

Capex to meet enhanced distribution reliability standards in NSW was identified as a key driver for the increase in Essential Energy's capex forecast. The increase in distribution network reliability standards in both NSW and Queensland has also contributed to the increase in capex allowances to meet higher peak demand for some DNSPs. The increase in standards also contributed to an overspend in capex in the previous regulatory period for the Queensland DNSPs, which is in turn an 'other factor' driving P_0 increases (see discussion in section 3.4.2).

Table 5.3
Key Drivers of Increase in Capex Allowance – DNSPs

DNSP	New customer connections*	Augmentation to meet peak demand growth	Environmental, safety and statutory obligations	Non-network assets	Asset renewal/ replacement	Quality, reliability and security of supply enhancement	SCADA & network control
Citipower	✓	✓	-	-	-	-	-
Powercor	✓	✓	✓	-	-	-	-
Jemena	✓	✓	✓	-	-	-	-
SP AusNet	✓	✓	✓	✓	-	-	-
United Energy	✓	✓	✓	✓	-	-	-
Ausgrid	-	✓	-	-	✓	-	-
Endeavour Energy	-	✓	✓	-	✓	-	-
Essential Energy	-	✓	-	-	✓	✓	-
ENERGEX	-	✓	-	-	✓	-	-
Ergon Energy	✓	✓	-	-	✓	-	-
ETSA Utilities	-	✓	-	✓	-	-	-
ActewAGL	-	✓	-	-	✓	-	✓

** Excluding customer contributions*

Table 5.4
Key Drivers of Increase in Capex Allowance – TNSPs

TNSP	New customer connections*	Augmentation to meet peak demand growth	Environmental, safety and statutory obligations	Asset renewal/ replacement	Quality, reliability and security of supply enhancement	Network IT and communications (SCADA)
SP AusNet	-	-	✓	✓	-	-
Ausgrid	-	✓	-	✓	✓	-
TransGrid	-	✓	-	✓	-	-
ElectraNet	✓	✓	-	✓	-	✓
Transend	✓	✓	-	-	-	-

** Excluding customer contributions*

5.3. The AER's assessment of the key drivers for increases in capex allowances

We have undertaken additional analysis in relation to those NSPs with P_0 increases above 15%, as indicated by our recalculated P_0 analysis (discussed in section 2.2). These NSPs are: Ausgrid,[29] Essential Energy, Ergon Energy, ENERGEX, ETSA Utilities, Endeavour Energy, ActewAGL, SP AusNet,[30] ElectraNet, Transend and TransGrid.

For each of these NSPs, we have assessed the extent to which the P_0 increase has been due to the increase in capex allowance between the current and previous regulatory periods. We have identified the increase in capex allowance as a major driver for the overall P_0 increase in the case of Ausgrid (both transmission and distribution), Essential Energy and ETSA Utilities.[31]

For these NSPs, we have then gone on to review:

- the reasons given by the NSP for the required increase in capex allowance, as set out in its initial regulatory submission to the AER; and
- the AER's assessment in its Draft and Final Decisions of the key drivers of the increase in the NSP's forecast capex, including any substantiating analysis it commissioned from independent consultants.

The focus of our review is on understanding to what extent the allowed increase in the capex allowance between regulatory periods for these NSPs reflects circumstances that the AER has determined are reasonable and justify the increased capex allowance, rather than indicating a shortcoming in the regulatory framework.

The detailed results of our analysis are set out below. However in summary we have found that:

- For **Ausgrid** (both transmission and distribution): the key drivers of the increase in capex allowance were (i) asset renewal/replacement; and (ii) augmentation to meet peak demand growth – with these two categories accounting for approximately 80% of the overall increase in the approved total capex forecast;
- For **Essential Energy**: the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; (ii) quality, reliability and security of supply enhancement; and (iii) asset renewal/replacement – with these three categories accounting for approximately 87% of the overall increase in the approved total capex forecast;
- For **ETSA Utilities**: the key drivers of the increase in capex allowance were (i) augmentation to meet peak demand growth; and (ii) non-network capex - with these two

[29] Both distribution and transmission.

[30] Both distribution and transmission.

[31] We have considered the impact of the increase in capex allowances to be a 'major' driver of P_0 increases for these businesses where it has resulted in a P_0 of more than 10%. We note that this cut-off point is essentially arbitrary and has been adopted only in order to contain the analysis, and to focus our review on the key drivers of the larger network price increases.

categories accounting for approximately 69% of the overall increase in the approved total capex forecast

For all three NSPs, the key drivers of the increase in capex forecast were examined by independent engineering consultants appointed by the AER, with both the consultants and the AER concluding that the capex allowance for these categories reflected the prudent and efficient level of expenditure. The evidence therefore indicates that for these NSPs, the key drivers of the increase in capex allowances, and ultimately network price increases, reflect circumstances (eg, increases in peak demand; asset condition) which were recognized as legitimate drivers of expenditure by the AER and its consultants, rather than reflecting a failing in the regulatory regime.

5.3.1. Ausgrid

The increase in the real capex allowance in the current regulatory period for Ausgrid's distribution business was $3.58bn (June 2009$)(ie, 85%). The increase in capex allowance accounted for 18.6% of the overall 58.3% P_0 increase in Ausgrid's distribution charges.

The information template completed by Ausgrid identifies the key drivers for the increase in Ausgrid's distribution capex allowance as:

- Asset renewal/replacement – which increased from $1.2bn to $2.9bn (June 2009$). This category contributed 56% of the total increase in the real capex allowance; and
- Augmentation to meet peak demand growth - which increased from $1.7bn to $2.4bn (June 2009$). This category contributed 24% of the total increase in the real capex allowance.

Overall these two categories account for approximately 80% of the total increase in real capex forecast.

The increase in the real capex allowance in the current regulatory period for Ausgrid's transmission business was $783m (June 2009$)(ie, 195%). The increase in capex allowance accounted for 29.9% of the overall 46.8% P_0 increase in Ausgrid's transmission charges.

As with distribution, the information template completed by Ausgrid identifies the key drivers for the increase in Ausgrid's transmission capex as:

- Asset renewal/replacement – which increased from $158m to $573m (June 2009$). This category contributed 53% of the total increase in the real capex allowance; and
- Augmentation to meet peak demand growth - which increased from $177m to $327m (June 2009$). This category contributed 19% of the total increase in the real capex allowance.

Overall these two categories account for approximately 72% of the total increase in real capex forecast.

5.3.1.1. Asset renewal/replacement capex

Ausgrid (known at the time as EnergyAustralia) specified asset age and condition as the primary driver for renewal/replacement capex in its initial regulatory proposal.[32] In particular Ausgrid highlighted that the key drivers of replacement capex were the need to replace or convert 11kV switchboards incorporating oil-filled switchgear and the need to replace oil and gas-filled transmission and sub–transmission cables due to their poor circuit availability.[33] Ausgrid also noted that sections of its network were at or near the end of their lives and that failure to replace the aged equipment would result in increasing levels of functional failures, with associated safety, reliability and cost impacts.[34]

The AER retained Wilson Cook in an external consultant role to review Ausgrid's proposed replacement capex. Wilson Cook undertook a detailed review of a number of particular projects in the area plans and in each instance considered the replacement capex proposed by Ausgrid to be prudent and efficient.[35] Further, Wilson Cook also reviewed in detail a number of the sub-programs in Ausgrid's replacement plan and in each instance considered the replacement capex proposed by Ausgrid to be prudent and efficient.[36]

The AER summarised Wilson Cook's position on Ausgrid's proposed replacement capex as follows: [37]

> *"In reviewing EnergyAustralia's proposed replacement capex Wilson Cook was satisfied that EnergyAustralia had followed reasonable policies and procedures that included the identification of need and the determination of least-cost solutions.*
>
> *Wilson Cook considered that EnergyAustralia's proposed replacement capex (and its implicit timing) appeared reasonable. It considered that the consistent and rising trend in replacement expenditure was matched to EnergyAustralia's understanding of the age and condition of its network and the ability of EnergyAustralia to resource the substantial scope of works. Furthermore Wilson Cook considered that the scope of replacement work proposed was generally consistent with the reported fault rates and trends observed.*
>
> *In summary, Wilson Cook was satisfied that the scope of replacement work proposed by EnergyAustralia was prudent and efficient."*

The AER stated it is draft determination that it was "satisfied that the proposed replacement forecast capex reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives".[38]

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32 EnergyAustralia, (2008), *Regulatory Proposal*, 2 June 2008, p. 55,

33 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 479

34 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 480

35 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 481

36 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 481 – 482.

37 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 482.

38 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 483.

5.3.1.2. Augmentation to meet peak demand growth

Ausgrid also identified peak demand growth as a major driver of future capex.[39]

In assessing Ausgrid's proposed growth capex, the AER retained Wilson Cook as an external consultant. The AER also retained McLennan Magasanik Associations (MMA) to conduct a separate independent review of Ausgrid's demand forecasts. In summary, MMA found Ausgrid's peak demand forecasts to be reasonable and acceptable for the purposes of assessing its augmentation capex proposal for the next regulatory control period.[40]

In its review of Ausgrid's proposed growth capex, Wilson Cook examined a number of Ausgrid's area plans in detail and in each instance concluded that the growth capex proposed by Ausgrid was prudent and efficient.[41] Wilson Cook also reviewed Ausgrid's 11 kV network development model, customer connections plan, low voltage capacity plan and property plan and it considered that they were well established documents that set out a prudent and efficient development strategy for the network and its related facilities.[42]

The AER summarised Wilson Cook's position on Ausgrid's proposed growth capex as:[43]

> *"Wilson Cook considered that the analysis undertaken by EnergyAustralia was comprehensive for the type of assets concerned. Importantly, Wilson Cook considered that EnergyAustralia appropriately determined the need for the proposed growth related projects, gave consideration to the least cost options, considered the optimal timing of the projects and maintained consistency with its policies and broader plans."*

In its draft determination, the AER stated that:[44]

> *"The AER has reviewed EnergyAustralia's supporting documentation, including its area plans, 11kV network development model, customer connections plan, low voltage capacity plan and property plan, and engaged in discussions with EnergyAustralia about its growth-related capex. The AER has also considered the advice provided by Wilson Cook and its own assessment of the impact of demand forecasts on the timing of specific projects. Taking into account all of these factors, the AER is satisfied that the proposed growth-related capex reasonably reflects the efficient costs a prudent operator, in the circumstances of EnergyAustralia, would require to achieve the capex objectives and is based on a realistic expectation of demand forecasts and cost inputs, consistent with the capex criteria in clause 6.5.7(c)."*

[39] EnergyAustralia, (2008), *Regulatory Proposal*, 2 June 2008, p. 55,

[40] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 476.

[41] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

[42] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

[43] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 477.

[44] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 479.

5.3.2. Essential Energy

The increase in the real capex allowance in the current regulatory period for Essential Energy was $1.59bn (June 2009$) (ie, 71%). The increase in capex allowance accounted for 15.7% of the overall 49.7% P_0 increase.

The information template completed by Essential Energy identifies three categories of capex as being primarily responsible for the increase in forecast capex, ie:

- Augmentation to meet peak demand growth– which increased by $762m to $1,341m ($June 2009), contributing 37% of the total increase in real capex;
- Quality, reliability and security of supply enhancement - which increased by $429m to $875m ($June 2009), contributing 28% of the total increase in real capex; and
- Asset renewal/replacement capex - which increased $444m to $795m (in $June 2009), contributing 22% of the total increase in real capex.

Overall these three categories account for approximately 87% of the total increase in real capex forecast.

5.3.2.1. Augmentation to meet peak demand growth

In its initial regulatory proposal, Essential Energy (then known as Country Energy) submitted that the key driver of capex relating to peak demand growth was the forecast annual growth rate for summer and winter peak demand of 3.0% and 1.8%, respectively, for the next regulatory control period, with a shift from a winter to a summer system peak expected during 2012–13.[45] Growth related programs proposed by Essential Energy for the regulatory period included:[46]

- New sub–transmission lines, and capacity and thermal upgrades to existing lines, looping of the network at the sub–transmission level and powerline route and easement acquisitions for future works.
- Construction of new zone substations and capacity upgrades to existing ones, installation of capacitor banks, upgrading of zone substation switchgear and protection systems and land purchases for future substation sites.
- Construction of new urban distribution feeders and interconnections between existing ones to create a meshed network to address shortfalls in load transfer capabilities, upgrading of existing urban feeders, extension and uprating of existing rural feeders facing capacity constraints, new and upgraded distribution substations, and transformers and new augmented low voltage circuits.
- Installation of customer metering for new residential, commercial and industrial developments and connections and installation of load control equipment.

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[45] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 135-136.

[46] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 438.

The AER engaged Wilson Cook in an external consultant role to review the augmentation proposed by Essential Energy to meet peak demand. Wilson Cook noted that, unlike the other DNSPs, Essential Energy has a very large service region defined by numerous small networks and a commensurately large number of smaller capex projects and, as a result, they adopted a sampling approach focussing on the projects representing the largest investment during the next regulatory control period.[47] The AER summarised Wilson Cook's conclusions on the two sub-categories of capex projects and programs sampled (sub-transmission augmentation and distribution) as follows:[48]

> *"Wilson Cook concluded that the proposed work [sub-transmission augmentation] was unexceptional and supported adequately by documentation and explanation. It concluded that there were no grounds on which to deem that the costs applied to Country Energy's growth capex program were inefficient…Wilson Cook considered that Country Energy's expenditure under the categories of distribution lines, low voltage lines and customer metering and load control is in line with levels incurred during the current regulatory control period, and therefore considered the projections to be reasonable."*

Taking Wilson Cook's advice into account, the AER stated in its draft determination that it "considers the proposed augmentation capex program reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives".[49]

5.3.2.2. Quality, reliability and security of supply enhancement

In its initial regulatory proposal, Essential Energy stated that the increase in capex required for quality, reliability and security of supply enhancement was being driven by the need to comply with design planning and reliability criteria licence conditions, requiring reinforcement of the distribution network to N-1 standards, remediation of individual poor performing feeders and improvement of average feeder reliability.[50] Specifically, Essential Energy proposed five key reliability and quality of supply investment programs for the regulatory control period: [51]

1. Urban distribution reinforcement program to satisfy N-1 security of planning criteria for high voltage distribution feeders in regional centres (as set out in their licence conditions);
2. Improving average feeder reliability performance of urban and short rural feeders, to a 20% probability of exceeding the SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index) targets set in the licence conditions;
3. Maintaining an average feeder reliability performance for long rural feeders, to meet the SAIDI and SAIFI targets set in the licence conditions;
4. Improving individual feeder reliability performance for SAIDI and SAIFI towards the standards set in the licence conditions; and

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[47] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 438.

[48] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 439-440.

[49] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 441.

[50] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 444.

[51] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, pp. 444-445.

5. System wide steady-state voltage improvement program.

The AER had Wilson Cook review Essential Energy's proposed quality, reliability and security of supply enhancement capex. Wilson Cook concluded that the capex associated with all five of the reliability and quality of supply investment programs was reasonable.[52]

Taking Wilson Cook's advice into account, the AER concluded in its draft determination: [53]

> *"[T]hat Country Energy's proposed projects and programs are necessary to maintain the ongoing security and reliability of its network, and to meet statutory obligations, and reasonably reflect the efficient costs required by a prudent operator to meet the capex objectives. In reaching this conclusion, the AER has considered the advice of Wilson Cook with respect to the efficiency of the expenditure and also the analysis undertaken by Country Energy regarding the prudence of its targeted level of compliance with the licence conditions relating to average feeder reliability."*

5.3.2.3. Asset renewal/replacement capex

In its initial regulatory proposal, Essential Energy specified approximately $814 million of capex for asset renewal/replacement.[54] Specifically, Essential Energy noted that "the need for asset renewal is largely brought about by the physical condition and age of the in service asset and/or component item".[55]

In reviewing Essential Energy's initial proposal for asset renewal/replacement capex, the AER engaged Wilson Cook to undertake an independent review. Wilson Cook reviewed each category of proposed renewal and replacement expenditure and concluded that the scope of the proposed works were 'reasonable and efficient'.[56]

Taking Wilson Cook's advice into account, the AER concluded in its draft decision that:[57]

> *"Country Energy's proposed renewal and replacement programs are necessary to maintain the ongoing security and reliability of its network, and to meet reliability obligations. The AER is satisfied that this aspect of Country Energy's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives."*

52 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 448.

53 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 449.

54 Country Energy, (2008), Country Energy's Electricity Network Regulatory Proposal 2009-2014, 2 June 2008, p. 144.

55 Country Energy, (2008), Country Energy's Electricity Network Regulatory Proposal 2009-2014, 2 June 2008, p. 105.

56 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 443.

57 AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008, p. 444.

5.3.3. *ETSA Utilities*

The increase in the real capex allowance in the current regulatory period for ETSA Utilities was $824m (June 2010$) (ie, 107%). The increase in capex allowance accounted for 10.6% of the overall 36.4% P_0 increase.

The information template completed by ETSA Utilities identifies the following main drivers of the increase in capital allowance:

- Augmentation to meet peak demand growth - increased from $204m to $615m ($June 2010), contributing 50% of the total increase in real capex; and
- Non-network asset capex - increased from $173m to $331m ($June 2010), contributing 19% of the total increase in real capex.

These two categories accounted for almost 70% of the total increase in real capex between the regulatory periods.

5.3.3.1. Augmentation to meet peak demand growth capex

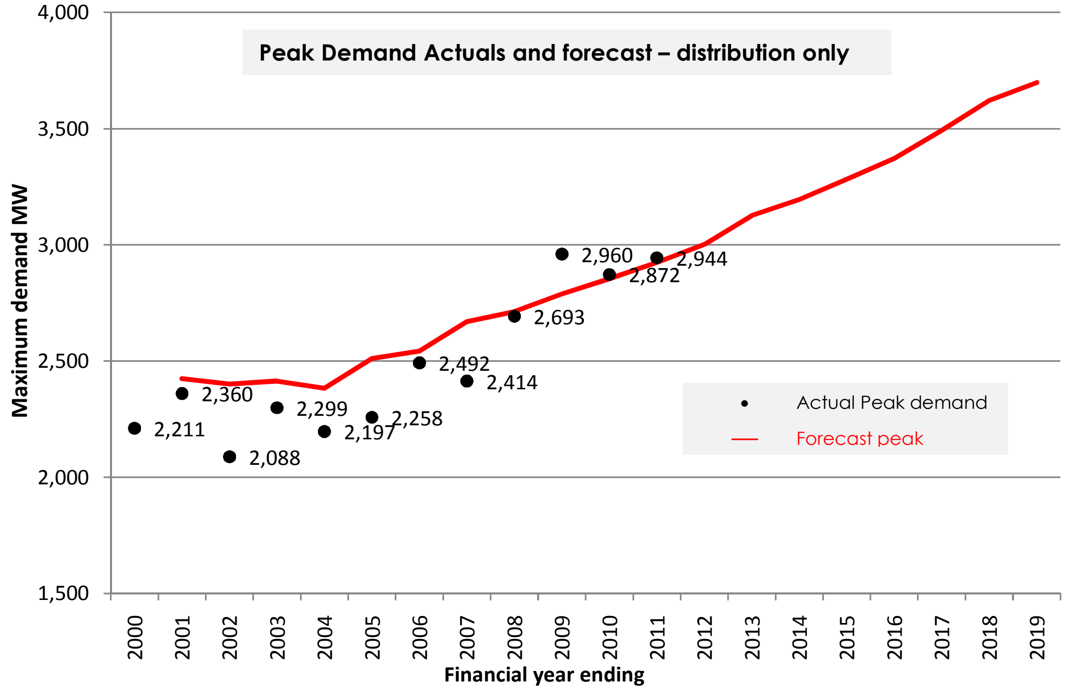
ETSA Utilities proposed $776m of ‘capacity’ demand driven capex in its initial regulatory proposal, to respond to peak demand growth.[58] The proposed increase was attributed to peak demand growth, changes to the South Australian Electricity Transmission Code requiring downstream work on ETSA’s distribution network, and the need to alleviate forecast network constraints (due to network utilisation approaching maximum prudent limits).[59]

Figure 5.3 shows the historical and forecast growth in peak demand across ETSA Utilities’ distribution network.

[58] AER, (2009), *South Australia Draft Distribution Determination 2010–11 to 2014–15*, Draft Decision, 25 November 2009, p. 128. ‘Capacity’ demand driven capacity encompasses capex required to meet peak demand growth. The other category classed as ‘demand driven’ capex in the case of ETSA was customer connections.

[59] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 128.

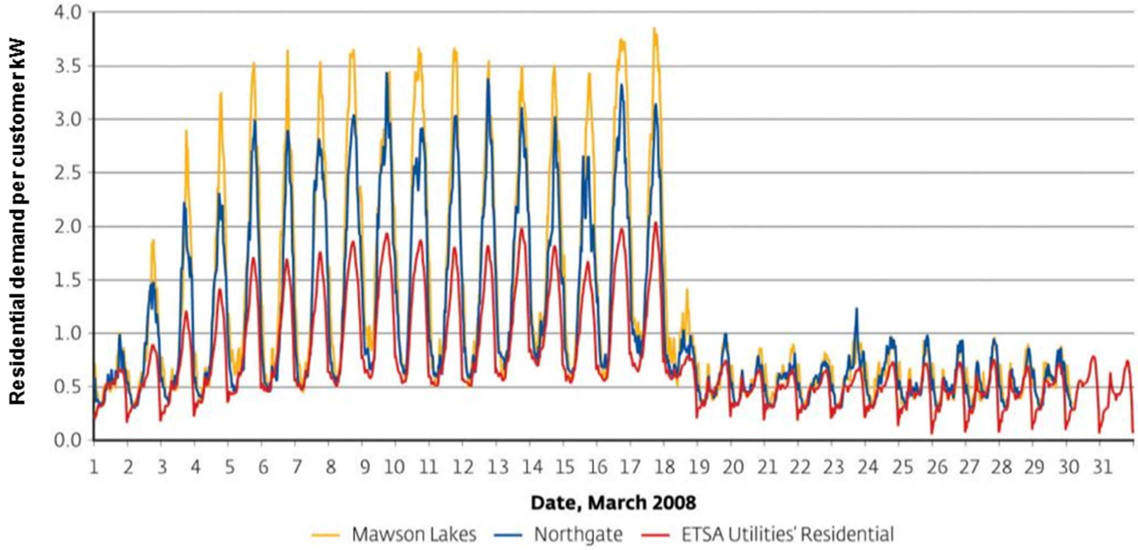
Figure 5.3
ETSA Utilities Peak Demand – Actuals and Forecast, 2000-2019



Source: ETSA Utilities

Figure 5.4 shows the change in demand that occurs in South Australia during extended heatwaves. We understand from ETSA Utilities that this step up in demand is primarily driven by the very high penetration rate of airconditioners (which are constantly being upgraded in size) combined with the poor passive performance of modern dwellings during heatwaves. This is evidenced by the higher peak demand in more modern suburbs (such as Mawson Lakes, shown by the yellow line in Figure 5.4) compared with the state average (shown by the red line in Figure 5.4).

Figure 5.4
ETSA Utilities – Change in Demand in South Australia during Extended Heatwaves



Source: ETSA Utilities.

As part of the draft decision process, the AER retained Parsons Brinkerhoff (PB) to review ETSA's capacity related capex. Specifically, PB:[60]

- assessed whether ETSA Utilities was acting efficiently in accordance with good electricity industry practice, through a review of capital governance, policy and procedures, cost estimating practices, and specific reviews of certain expenditures;
- assessed whether there was a justifiable need for the proposed capital investment within each expenditure category;
- after confirming the need for a capital investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need; and
- where a capital investment was based on assumptions about future conditions, assessed whether those assumptions were reasonable.

In the case of ETSA Utilities' proposed demand-driven capex, PB found that ETSA's planning criteria, capex governance, options analysis and cost estimation procedures were all appropriate. The only adjustments recommended by PB were to the low voltage network upgrade program (which represented 16% of the overall expenditure proposed to meet peak demand).[61] Specifically, PB noted that ETSA's risk assessment underpinning the low voltage

[60] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 111.

[61] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, Draft Decision, 25 November 2009, p. 134.

capacity upgrade program overstated the risk, and ETSA proposed low voltage planning criteria were more conservative than those applied by other Australian DNSPs.[62]

In the final decision, the AER concluded that it was satisfied that reducing ETSA's proposed demand driven capex by $39 million (to reflect adjustments to the capex proposed for the low voltage network) would result in expenditure that reasonably reflects the capex criteria.[63]

In its media release in relation to the South Australia distribution determination issued on 6 May 2010 the AER stated:[64]

> *"More than half of this expanded [capex] program is required to ensure the capacity of the network meets future demand from both new and existing customers, including meeting the continuing growth in peak demand. The load is growing as customers continue to install air conditioners and other appliances. In addition, there is need to address risks associated with ageing assets to maintain reliability for customers."*

5.3.3.2. Non-network asset capex

In its initial regulatory proposal, ETSA proposed non-system capex of $364 million - an increase of 98% from the level of non-system capex proposed in the earlier regulatory period. This represented approximately 13% of the total proposed capex program and included expenditure on information technology, property, fleet, and plant and tools.[65]

Specifically, ETSA Utilities has identified the key drivers of the increase of non-network capex as:[66]

- Renewal of major IT systems, IT support for increased network capital program, new Network Operations Centre;
- Existing property maintenance and upgrades. To meet changing field requirements, relocation of existing depots, establishment of new offices and depots;
- New vehicles for increases employee numbers and capital program, legislative required updates to vehicles; and
- Plant and Tools associated with new vehicles, building plant.

In assessing ETSA's proposed non-system capex, the AER retained PB in an independent reviewer role. PB found ETSA's initially proposed non-system capex to be prudent and efficient and did not recommend any adjustments to the proposed expenditure on that basis.[67] Specifically, the AER summarised PB's view as:[68]

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[62] AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, Final Decision, May 2010, p. 74.

[63] AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, Final Decision, May 2010, p. 79.

[64] AER Media Release, 6 Mat 2010 – available at: http://www.aer.gov.au/content/index.phtml/itemId/736389/fromItemId/746345

[65] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 166.

[66] Information provided by ETSA Utilities in survey template to NERA.

[67] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 168-169.

[68] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 113.

> *"PB has assessed ETSA Utilities' proposed non–system capex, including capex for information systems, plant and tools, property and fleet categories, and found the proposed non–system capex to be prudent and efficient. A reduction of $25 million (6%) to the non–system capex is recommended to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009–10 basis."*

In its draft determination, the AER noted PB's conclusion and itself concluded that ETSA's proposed non-system capex was prudent and efficient, although the AER did make an adjustment to real cost escalators of $107m.[69] Further, the AER noted the cyclical nature of certain elements of the non–system capex, such as costs associated with the replacement of IT systems and the timing of fleet replacement expenditures.[70]

ETSA reflected the AER draft determination findings for non-system assets in its revised regulatory proposal.[71]

[69] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 171.

[70] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 171.

[71] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 70.

6. Drivers of the Increase in Opex Allowances

The analysis in section 3.3 highlights that the increase in opex allowances in the current regulatory period compared to the previous regulatory period has had a substantive impact on P_0 increases.

As in the case of capex allowances, we have sought to identify the drivers behind the increase in opex allowances. Again, we first assess if changes in real costs are a significant component of the increases in opex allowances. We then look at the other key drivers of the increase in opex allowances.

6.1. Real cost escalation

Part of the increase in the opex allowances in the current regulatory period is due to real cost escalation. In particular, materials costs, construction costs, land and labour rates have generally been increasing in real terms.

As discussed in section 5.1 above, in order to estimate how much of the increase in opex allowance is due to real cost escalation, we have used real cost indices commissioned by ENA from SKM. SKM have developed ‘typical’ transmission and distribution network capex and opex real cost escalators. The real cost indices developed by SKM are reproduced in Appendix C.

Table 6.1 sets out the increase in the real opex allowance between the current and previous regulatory periods for each DNSP.

Table 6.1
Change in Opex Allowance Due to Real Cost Escalation - DNSPs

Business	Change in real opex
Ausgrid	1.9%
Essential Energy	1.9%
ActewAGL	2.0%
Endeavour Energy	1.9%
ENERGEX	2.0%
Ergon Energy	2.1%
ETSA Utilities	2.1%
United Energy	2.4%
CitiPower	2.4%
Powercor	2.4%
SP AusNet	2.2%
Jemena	2.1%

Table 6.2 provides the same breakdown for TNSPs.

Table 6.2
Change in Opex Allowance Due to Real Cost Escalation - TNSPs

Business	Change in real opex
Ausgrid	1.9%
ElectraNet	3.1%
Transend	1.9%
TransGrid	1.9%
SP AusNet	3.5%

It is evident from the above that, unlike capex, increases in real costs are a driver of the increase in the opex allowance in the most recent regulatory period. However, they are only a modest driver – estimated to contribute real increases of between 1.9% and 2.4% for DNSPs and between 1.9% and 3.5% for TNSPs of total opex.

As discussed earlier, the AER is not constrained under the Rules in substituting its own real cost escalation indices. Indeed, the AER has chosen to substitute its own real cost escalators in all of its final determinations for DNSPs and TNSPs. As a consequence, the increase in network charges due to the impact of real cost escalation on opex allowances does not indicate a shortcoming in the operation of the Rules.

6.2. Key drivers of the increase in opex allowances

Part of the survey template circulated to the DNSPs included a breakdown of the opex allowance in the current and previous regulatory periods into base year and step-changes.

Table 6.3 presents the percentage of the total opex allowance due to step-changes. It is evident from this analysis that the importance of step-changes in driving overall opex allowances varies across DNSPs.

Table 6.3
Step-changes as a Percentage of Total Opex Allowance – DNSPs

Business	Proportion
SP AusNet	22%
ETSA Utilities	20%
Jemena	13%
ENERGEX	16%
Essential Energy	15%
ActewAGL	14%
Powercor	11%
CitiPower	11%
United Energy	10%
Ausgrid	6%
Endeavour Energy	4%
Ergon Energy	0%

6.3. The AER's assessment of the key drivers for increases in opex allowances

We have again undertaken additional analysis in relation to those NSPs with P_0 increases above 15%, as indicated by our recalculated P_0 analysis.

For each of these NSPs we have assessed the extent to which the P_0 increase has been due to the increase in opex allowance between the current and previous regulatory periods. We have identified the increase in opex allowance as a major driver for an overall material P_0 increase in the cases of Ausgrid (distribution), ActewAGL, ETSA Utilities, and Transend.[72]

For these NSPs, we have reviewed:

- the reasons given by the NSP for the required increase in opex allowance, as set out in its initial regulatory submission to the AER; and
- the AER's assessment in its Draft and Final Decisions of the key drivers of the increase in the NSP's forecast opex, including any substantiating analysis it commissioned from independent consultants.

The focus of this analysis is again on understanding to what extent the allowed increase in forecast opex between regulatory periods reflects circumstances that the AER has determined are reasonable and justify the allowed increase, rather than indicating a shortcoming in the Rules.

In summary, we have found that the drivers behind the increase in opex reflect a combination of factors, such as real wages growth (increased legislative obligations (including feed-in tariffs) and an expansion of the capital base). For the businesses we reviewed, in all cases the AER had the NSP's forecasts reviewed by independent consultants. In the case of Transend, ActewAGL, ETSA Utilities and Essential Energy, the AER applied reductions to the allowed opex forecast over and above those that had been recommended by the external consultants.

6.3.1. Transend

Our PTRM analysis indicates that Transend's transmission revenues have increased approximately 32.5% since the previous regulatory period. Of the three factors investigated, changes in forecast opex were found to have had the greatest impact on this revenue increase. Specifically, treating every other change between periods as given, the increase in the real forecast operating expenditure alone would have resulted in a 10.6% increase in Transend's revenues.

Transend's initial regulatory proposal included forecast opex of \$281 million.[73] Transend identified the following high level drivers of the increase in forecast opex:[74]

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[72] We have considered the impact of the increase in opex allowances to be a 'major' driver of P_0 increases for these businesses where it has contributed more than 10% of the overall change in P_0. We note that this cut-off point is essentially arbitrary and has been adopted only in order to contain the analysis, and to focus on the drivers of the larger network price increases.

[73] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14,* Draft Decision, 21 November 2008, p. 158.

- Increasing real wage growth, driven by skills shortages in Australia;
- Increasing asset growth and additional resources to support capital program and systems control;
- Increased legislative obligations (such as compliance with the *Electricity Supply Industry (Network Performance Requirements) Regulations 2007*); and
- Other changing circumstances and obligations.

As part of the information gathering component of this assignment, Transend informed us that the allowance provided by the ACCC for the previous (ie, 2004-09) regulatory period was considered by Transend to provide unsustainably low expenditure allowances and , as a result, Transend incurred actual expenditure throughout the regulatory period which was greater than the allowance provided (which included increased costs associated with preparing for Tasmania's entry into the NEM and associated ongoing obligations). In fact, during the review of Transend's initial proposal for the current period, the AER's consultants, WorleyParsons stated in their report that:[75]

> *"WorleyParsons has studied the ACCC Decision on the level of Opex expenditure in the Current Regulatory Control Period, and does not understand the basis for that Decision."*

In its draft decision, the AER stated that it had compared Transend's opex in 2006-07 (the base year) against the efficient amount forecast in the 2003 revenue cap decision and Transend's actual opex in 2006-07 was $7.2 million higher than the efficient forecast amount in the ACCC decision of $33.3 million.[76] In its draft decision, the AER found that Transend's actual base year expenditure was efficient, effectively confirming that the ACCC decision allowance was insufficient.

Further, as part of its draft decision, the AER engaged WorleyParsons to provide an independent review of Transend's opex proposal. WorleyParsons reviewed Transend's business model, maintenance policies and processes, concluding that Transend was a relatively efficient TNSP.[77] Further, WorleyParsons concluded that the methodology and resulting forecast for all major[78] categories of controllable opex were considered reasonable.[79] WorleyParsons only recommended one minor adjustment to Transend's forecast opex, which was a reduction for one inventory officer position and totalled $0.4 million over the regulatory period (less than 1% of Transend's total proposed opex).[80]

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[74] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 159.

[75] WorleyParsons, (2008), *REVIEW OF THE TRANSEND TRANSMISSION NETWORK REVENUE PROPOSAL 2009 - 2014*, 23 October 2008, p. 12.

[76] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 166.

[77] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 161.

[78] Major categories are: field maintenance & operations; transmission services; transmission operations; asset management; and corporate.

[79] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 180-184.

[80] AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 161-162.

In its draft decision, the AER concluded that Transend's forecast total opex did not reasonably reflect the opex criteria and applied various reductions totalling $21.2 million (7.5%) to determine a total opex forecast of $260.2 million for the period.[81] As part of its draft decision, the AER made specific reductions to the labour escalation rates applied to controllable opex.[82]

Transend included a total opex forecast of $283 million as part of its revised opex proposal, which accepted most aspects of the AER's draft decision relating to forecast opex, except for:[83]

- Debt and equity raising costs;
- Labour and non-labour escalators; and
- Labour escalation for telecommunication costs.

As part of its final decision, the AER engaged a number of external consultants to review various aspects of Transend's revised opex proposal and concluded that the telecommunication costs submitted by Transend as well as the electricity, gas and water labour cost escalators submitted reasonably reflected the opex criteria.[84] However, overall, the AER concluded that it was not satisfied that Transend's total forecast opex reasonably reflected the opex criteria and applied a $29 million (10.2%) reduction to Transend's total forecast opex, comprising of:[85]

- a reduction of $11 million to equity raising costs - equity raising costs were removed from opex and the amount of equity raising costs calculated by the AER was capitalised; and
- a reduction of $18 million arising from the modelling - reflecting changes to asset growth (resulting from amended capex allowance), actual CPI for 2007–08 and 2008–09, removal of replacement capex for transitional services, and debt raising costs (resulting from amended capex allowance).

6.3.2. Essential Energy

Our PTRM analysis indicates that Essential's distribution prices have increased approximately 49.7% since the previous regulatory period. Of the three factors investigated, changes in forecast opex were found to have had the most significant effect on this price increase. Specifically, treating every other change between periods as given, the increase in the real forecast operating expenditure alone would have resulted in a 20.2% increase in Essential's prices.

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81 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 200-203.

82 AER, (2008), *Transend Transmission Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 202.

83 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. xv.

84 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, pp. 95 & 101.

85 AER, (2009), *Transend Transmission Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, 2008, pp. 121-122.

As part of the information gathering component of this assignment, we understand from Essential that step changes made up approximately 15% of the total allowed opex in the current regulatory period. Further, Essential informed us that the opex increase between periods was primarily caused by increases in vegetation management, maintenance and repairs and inspections. Specifically, Essential informed us that vegetation management accounted for the largest part of the increase in opex between the regulatory periods and that it increased for the following reasons:

- The introduction of Design, Reliability and Performance Licence Conditions which included the requirement for compliance with the feeder class reliability standards as well as the individual feeder reliability standards;
- Insufficient vegetation management costs had been included in Country Energy's previous regulatory proposal. This was due to the fact that Country Energy was formed in 2001 and the historical vegetation spends of the 3 predecessor organsisations did not accurately reflect the expenditure necessary to comply with the Industry Safety Steering Committee;
- Improved safety standards; and
- A new methodology was developed to more accurately forecast vegetation management expenditure requirements just prior to submitting the regulatory proposal for the 2009 to 2014 determination period.

Essential's initial regulatory proposal included a forecast opex amount of $2,160 million.[86] Of this total amount, approximately 98% was classified as 'controllable opex.' Essential identified the following significant drivers of controllable opex: [87]

- new, deferred and backlog asset inspection and maintenance works to mitigate risk and improve network performance;
- cost increases above inflation for labour and input materials; and
- increased workload due to additional assets.

As part of the draft decision, the AER engaged Wilson Cook to to review the controllable opex components of Essential's forecast opex proposal. Wilson Cook made the following comments with respect to Essential's proposed maintenance and repairs opex:[88]

> *"We reviewed the asset management plans and policies and the principles applied to the risk-based model used to derive the work programme. We found the maintenance strategies and processes used by Country Energy to be typical of electricity distribution businesses. Inspection cycles and routine maintenance activities were in line with industry standards. The process used to review and identify maintenance requirements appeared to be robust and appropriate. Based on our review, we are satisfied that Country Energy's maintenance policies and processes are appropriate and properly applied."*

[86] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 159.

[87] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 160.

[88] Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 40

Wilson Cook also made the following comments with respect to Essential's proposed inspections opex:[89]

> *"The new programmes include new initiatives to widen the scope of the inspection programme, including programmed internal inspection of all underground pits and pillars, six-monthly condition monitoring of critical distribution substations and ring main units, programmed live-line pole-top inspection of all radial sub-transmission feeders, a 'thermo vision' programme covering all critical equipment and urban network components and six monthly condition monitoring of all regulators and reclosers… We consider the increased scope of the proposed programmes reasonable and should enable the company to identify risks earlier and improve system performance."*

Further, Wilson Cook noted the following with respect to Essential's proposed vegetation management opex:[90]

> *"We have reviewed all the information provided on the vegetation management forecast. Much of the increased programme is new and targeted at different purposes to the historical programme. It will take some years before it can be established that the programme achieves the reliability improvements being targeted but use of the profiling data does provide a reasonable basis for estimating the required works."*

Overall, Wilson Cook concluded that its top-down review suggested that Essential's base year level of expenditure was low and may be below a prudent level to maintain targeted service levels.[91] However, Wilson Cook did recommend a $30 million reduction (1%) to the forecast controllable opex, as it did not consider that it was appropriate for Essential to apply an asset growth escalator to vegetation management, as it was unlikely that the quantity of vegetation management would be driven principally by growth capex.[92]

In its draft decision, the AER concluded that it was not satisfied that Essential's total forecast opex reasonably reflects the opex criteria. Taking into account Wilson Cook's advice as well as their own analysis, the AER applied a reduction of $185 million ($8.6%) to Essential's proposed opex.[93] Specifically, the AER's adjustment was comprised of the following components:[94]

- $135 million reduction to deferred expenditure (inspections, maintenance & repair and vegetation management);[95]

[89] Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 40

[90] Wilson Cook & Co, (2008), *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs*, Volume 4 – Country Energy, p. 41.

[91] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 167.

[92] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 167.

[93] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 198.

[94] Unless otherwise stated: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, pp. 198-199.

[95] Unless otherwise stated: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 174.

- a $25 million reduction to vegetation management escalation;
- an $8 million reduction to input cost escalators;
- a $12 million reduction to debt raising costs; and
- a $5 million reduction to self-insurance costs.

Essential did not accept the AER's conclusion on forecast opex in its revised proposal and included a forecast of $2,211 million for the regulatory period.[96] In its revised regulatory proposal, Essential clarified a number of points to the AER in relation to its vegetation management and in its final decision the AER concluded the following:[97]

> *"As such, Country Energy has alleviated the AER's key concerns by demonstrating that it is not proposing that consumers pay for the same service twice. Rather, in the current regulatory control period Country Energy undertook projects that were of a higher priority and provided benefits to customers."*

However, overall, in the final decision, the AER stated it was not satisfied that Essential's revised opex forecast reasonably reflected the opex criteria and, having undertaken its own analysis as well as engaging Wilson Cook and Energy and Management Services, applied a reduction of $159 million to the proposed total opex, ie, a reduction of around 7.2% compared with Essential's revised proposed opex.[98] Specifically, the AER's adjustment was comprised of the following components:[99]

- a $40.2 million reduction to the costs of project associated with Sheather decision;
- a $26 million reduction to vegetation management escalation;
- a $75 million reduction to input cost escalators;
- a $4 million reduction for revised capex forecasts;
- a $12 million reduction to debt raising costs; and
- a $5 million reduction to self-insurance costs.

However, the AER did conclude that the $135 million reduction to deferred expenditure made in the draft decision should be reinstated. Specifically, the AER concluded:[100]

> *"For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is satisfied that the reinstatement of $135 million ($2008–09) for vegetation management expenditure in Country Energy's forecast opex results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors."*

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96 AER, (2008), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 150.

97 AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 156.

98 AER, (2008), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 200.

99 AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, pp. 201-202.

100 AER, (2008), *New South Wales Distribution Determination 2009–10 to 2013–14*, Final Decision, 28 April 2009, p. 156.

6.3.3. ActewAGL

Our PTRM analysis indicates that, treating other changes between periods as given, the increase in the real forecast operating expenditure for ActewAGL contributed 18.2% to the overall 22.7% increase in network charges. We understand from ActewAGL that approximately 54% of the $108.8 million increase in opex between this regulatory period and the last is attributable to their Feed-in Tariff (FiT) scheme and the Utilities Network Facilities Tax (UNFT).[101]

ActewAGL's initial regulatory proposal included forecast opex of $306 million, which was approximately 36% greater than the forecast opex in the, then, current regulatory period.[102] ActewAGL identified the following significant drivers for the increase in opex in its initial regulatory proposal:[103]

- Increases in real wages and cost of raw materials;
- Asset base growth;
- Introduction of an enhanced pole inspection program; and
- Additional activities associated with the vegetation and bushfire mitigation inspection and management program.

The AER retained Wilson Cook to review ActewAGL's forecast opex, who concluded:[104]

> *"After considering both the "bottom-up" and "top-down" analyses, we accepted that improvements in efficiency will be made over the next period and concluded that the proposed opex should be accepted without adjustment."*

However, having considered the advice Wilson Cook, and undertaking their own analysis, the AER applied a reduction of $9.5 million (around 3%) to ActewAGL's proposed opex.[105]

In their revised proposal, ActewAGL did not accept the AER's conclusion on controllable opex and substituted an amount of $275 million that included: [106]

- revised labour cost escalators;
- new opex relating to service target performance incentive scheme (STPIS) reporting requirements; and
- new opex relating to the implementation of the FiT scheme.

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[101] Specifically, ActewAGL informed us that the FiT scheme and UNFT added $47.9 million and $10.8 million respectively (both $2008/09) to the total opex increase between periods.

[102] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 83.

[103] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 84.

[104] Wilson Cook, (2008), *ACT & NSW DNSP Expenditure Review – ActewAGL*, Final Report, October 2008, p. 39.

[105] AER, (2008), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Draft Decision, 7 November 2008, p. 119.

[106] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, pp. 50-51.

Further, ActewAGL also provided revised opex estimates for debt raising costs, equity raising costs, self-insurance and FiT scheme direct tariff payments. In total, ActewAGL's revised proposal increased the total opex forecast by $60 million to $359 million.[107]

In making its final decision, the AER engaged various consultants to review ActewAGL's revised opex forecasts and concluded that it was not satisfied that ActewAGL's forecast total opex reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.[108] Having considered the advice of the consultants, and undertaking its own analysis of ActewAGL's proposed opex, the AER applied a reduction of $18 million (5%) to ActewAGL's proposed opex.[109]

6.3.4. ETSA Utilities

Our PTRM analysis indicates that, treating other changes between periods as given, the increase in the real forecast operating expenditure for ETSA Utilities contributed 10% to the overall 36.4% increase in network charges.

As part of the information template ETSA completed, it identified that step changes in opex contributed approximately 20% of the total opex allowed in the current regulatory period. ETSA listed the following categories of opex as being major contributors to these step changes:[110]

- Feed in tariffs - $39 million;
- Asset inspections - $26 million;
- IT support - $28 million;
- Property costs & land tax - $21 million; and
- Insurance premiums and support - $21 million.

ETSA's initial regulatory proposal included forecast opex of $1,175 million, which was approximately 60% greater than the forecast opex for the, then, current regulatory period.[111] Of this total amount, approximately 89% was classified as 'controllable opex.' ETSA identified the following significant drivers of controllable opex:[112]

- ETSA submitted that its base year expenditure included a number of unusual expenditures that are likely to understate or overstate ETSA Utilities' longer-term efficient costs, ie,

[107] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 51.

[108] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 84.

[109] AER, (2009), Australian Capital Territory Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 84.

[110] We note that ETSA also identified network maintenance & planning ($14 million), superannuation contributions ($12 million) and operating support for significant increase in capex as being large contributors to the step changes.

[111] AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 182.

[112] Unless otherwise stated: AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 185-186 & 201 - 202.

vegetation management, telecommunications, debt raising costs, self-insurance, regulatory proposal, demand management and finance adjustments;

- Changing risk profile of the distribution network, ie, intensifying its asset condition monitoring regime;[113]
- Impact of the capex program being substantially greater than the last period;[114]
- Changes associated with economic factors, ie, costs associated with superannuation contributions and insurance premiums were expected to increase significantly due to the global financial crisis;[115]
- Changes in regulatory, legal, or tax obligations, ie, land tax, meter maintenance and feed-in tariffs;[116]
- Changing community expectations through a series of 'formal and informal' methods of engagement with the community;[117]
- Other changes in scope including full retail contestability systems support, aerial inspections and Davenport Training Centre;
- Scale escalation – primarily network growth; [118] and
- Input cost escalation– primarily labour costs.[119]

As part of the draft decision, the AER engaged PB to provide an independent assessment of ETSA's forecast opex proposal. Based on its review, PB found that 96% of ETSA's $1,175 million of proposed opex was prudent and efficient and recommended that the forecast opex be reduced by $46 million (ie, a 4% reduction).[120]

In its draft decision, the AER concluded that it was not satisfied that the opex forecast reasonably reflects the opex criteria, including the opex objectives.[121] The AER concluded that an adjustment in forecast opex to $1,044 million (ie, a reduction of 11% compared with ETSA's initial proposal) would reasonably reflects the opex criteria, being the minimum adjustment necessary for the total forecast opex to comply with the NER.[122]

ETSA did not accept the AER's conclusion on forecast opex in its revised proposal and included a revised forecast of $1,082 million.[123] As part of its final decision, the AER again engaged PB to review the revised opex proposal put forward by ETSA, who recommended

113 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 158.

114 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 164.

115 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 161.

116 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 162.

117 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 166.

118 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 171.

119 ETSA Utilities, (2009), *ETSA Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 177.

120 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 189.

121 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, pp. 243 -245.

122 AER, (2009), South Australia Draft Distribution Determination 2010–11 to 2014–15, 25 November 2009, p. 245.

123 AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, May 2010, p. 108.

reductions to ETSA's revised proposed opex totalling approximately $12 million (1%).[124] Having considered the advice of PB as well as its own review, the AER made a series of specific adjustments to ETSA's revised opex proposal resulting in a total opex forecast of $1,033 million (ie, 12 % below ETSA's initial proposal) and concluded that it was satisfied this amount reasonably reflected the opex criteria, taking into account the opex factors.[125]

6.3.5. Ausgrid

Our PTRM analysis indicates that the increase in opex forecast for Ausgrid contributed 15.6% to the overall 58.3% P_0 change from the previous regulatory period.

Ausgrid's initial regulatory proposal included a forecast opex amount of $3,047 million. [126] Of this total amount, approximately 97% was classified as 'controllable opex.' Ausgrid identified the following significant drivers of controllable opex:[127]

- Increased workload largely arising from the larger asset base, adding approximately 25% to network maintenance costs;
- Increased network maintenance costs associated with the increasing age of assets;
- Cost increases above inflation;
- Step changes arising from:
  - the higher costs of IT due to the introduction of new systems;
  - an increased property portfolio to meet the expanded capex requirements as well as corporate property expenses; and
  - a need to meet statutory and regulatory obligations.

As part of its draft decision, the AER engaged Wilson Cook to to review the controllable opex components of Ausgrid's forecast opex proposal. The AER summarised Wilson Cook's main findings as:[128]

- Ausgrid's base year opex is at or a little above the industry norm, but could not be considered inefficient;
- Ausgrid's cost efficiency relative to the other NSW and ACT DNSPs will deteriorate and, unless reasons can be established why Ausgrid should move further away from an

[124] Parsons Brinkerhoff, (2010), Review of ETSA Utilities' Revised Regulatory Proposal for the Period July 2010 to June 2015, May 2010, pp. 29 – 41.

[125] AER, (2010), South Australia Distribution Determination 2010–11 to 2014–15, May 2010, p. 142.

[126] AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 162. Note that the discussion in this section refers to the total opex proposed by Ausgrid across both their transmission and distribution activities, as these amounts were not separately identified in the AER's draft and final decisions (see: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 174)

[127] Communication with Ausgrid as well as: AER, (2008), *New South Wales Draft Distribution Determination 2009–10 to 2013–14*, Draft Decision, 21 November 2008, p. 162.

[128] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, pp. 167-168.

industry norm level of opex, the level of opex in the next regulatory control period cannot be considered to be efficient; and

- Wilson Cook proposed adjustments to remove most of the step changes proposed by Ausgrid as they were found not to be supported by considerations of business efficiency improvements or potential cost savings.

In total, Wilson Cook recommended a reduction of $316 million (11%) to Ausgrid's total opex forecast.[129]

Noting Wilson Cook's advice, as well as its own analysis, the AER applied a series of reductions totalling $410 million (13%) to Ausgrid's proposed opex in its draft decision, which resulted in a revised forecast opex allowance of $2,638 million.[130]

In its revised regulatory proposal, Ausgrid rejected all of the reductions made by the AER in its draft decision.[131] Ausgrid proposed a revised total opex allowance of $2,991 million, which represented a reduction of $80 million from its initial regulatory proposal but was $353 million greater than the amount of opex allowed by the AER in its draft decision.[132] Ausgrid's rejection of the AER's adjustments was based on the following arguments:[133]

- The AER and Wilson Cook did not consider all of the material in Ausgrid's initial proposal;
- The AER uncritically relied on Wilson Cook's analysis rather than supplementing it with its own analysis; and
- Much of Wilson Cook's analysis was flawed.

Ausgrid provided additional information in support of its revised regulatory proposal, including four new consultancy reports.

As part of its final decision, the AER again engaged Wilson Cook to review the components of Ausgrid's revised opex proposal. In total, Wilson Cook recommended a reduction of 12% compared with Ausgrid's revised total opex proposal.[134] Based on the advice provided by Wilson Cook as well as their own analysis, the AER applied a reduction of $363 million (around 12%) to Ausgrid's revised total opex proposal, resulting in a revised forecast opex allowance of $2,628 million.[135]

We note that Ausgrid appealed to the Tribunal regarding the AER's final decision on Ausgrid's proposed step changes as well as a number of other minor factors. However, the Tribunal affirmed the AER's decisions in the majority of cases, noting that the only step

[129] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 168.

[130] AER, (2008), New South Wales Draft Distribution Determination 2009–10 to 2013–14, Draft Decision, 21 November 2008, p. 199.

[131] AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 151.

[132] AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 151.

[133] AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 152.

[134] AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 202.

[135] AER, (2009), New South Wales Distribution Determination 2009–10 to 2013–14, Final Decision, 28 April 2009, p. 202.

change that should not be reduced to zero was that relating to ‘finance and commercial – business systems’.[136]

[136] Australian Competition Tribunal, (2009), Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8, 12 November 2009, Para. 203.

Appendix A. Results of P_0 Analysis for each NSP

Table A.1
Victoria: Scenario Changes in P_0

	CitiPower	Powercor	JEN	SP AusNet	United Energy	DNSP weighted average	Change	SP AusNet*	Change
P_0 (assume X2-5 = 0)	-1.4%	-6.3%	-11.0%	-19.2%	-5.6%	-9.7%		-15.3%	
(NPV of revenue)	$903.8	$1,907.7	$751.2	$1,872.1	$1,272.0			$2,158.0	
WACC (including franking)	3.4%	-2.2%	-4.4%	-12.9%	-1.8%	-4.6%	-5.1%	-12.0%	-3.2%
(NPV of revenue)	$878.2	$1,871.5	$731.7	$1,822.4	$1,251.3			$2,158.1	
Capex	-0.2%	-2.9%	-9.4%	-12.4%	-1.4%	-5.6%	-4.1%	-12.2%	-3.1%
(NPV of revenue)	$893.0	$1,847.0	$740.4	$1,765.4	$1,221.3			$2,100.2	
Opex	-0.2%	-2.6%	-14.6%	-10.0%	-2.8%	-5.7%	-3.9%	-14.2%	-1.1%
(NPV of revenue)	$892.9	$1,841.6	$775.7	$1,728.4	$1,238.0			$1,763.1	
WACC, Capex & Opex	5.5%	4.4%	-6.8%	2.3%	4.9%	2.7%	-12.4%	-5.5%	-9.8%
(NPV of revenue)	$859.9	$1,750.9	$748.3	$1,578.1	$1,169.3			$1,646.9	

Source: NERA analysis.

** We have assumed middle of the financial year (ending in 31 March) dollars for forecast capex/opex approved in the previous regulatory period and brought them forward to March 2008 dollars. We have also created a '6th year' of capex/opex for the last regulatory period (consistent with the current PTRM) by averaging the 5 years of approved forecasts.*

Table A.2
New South Wales: Scenario Changes in P_0

	Ausgrid	Endeavour Energy	Essential Energy	DNSP weighted average	Change	Transgrid	Ausgrid	TNSP weighted average	Change
P_0 (assume X2-5 = 0)	-58.3%	-32.9%	-49.7%	-49.3%		-18.2%	-46.8%	-24.1%	
(NPV of revenue)	$6,319.5	$3,591.6	$4,515.3			$2,981.4	$771.9		
WACC (including franking)	-43.7%	-21.8%	-38.3%	-36.5%	-12.8%	-9.5%	-30.8%	-13.9%	-10.2%
(NPV of revenue)	$5,964.9	$3,441.8	$4,346.4			$2,837.1	$728.6		
Capex	-39.7%	-23.4%	-33.9%	-33.7%	-15.6%	-8.8%	-17.0%	-10.3%	-13.8%
(NPV of revenue)	$5,578.4	$3,346.2	$4,044.6			$2,744.7	$614.9		
Opex	-42.7%	-23.1%	-29.5%	-33.6%	-15.6%	-14.0%	-42.0%	-19.7%	-4.4%
(NPV of revenue)	$5,697.4	$3,337.2	$3,911.0			$2,874.0	$746.3		
WACC, Capex & Opex	-12.2%	-3.8%	-4.5%	-7.6%	-41.7%	2.8%	-3.7%	1.6%	-25.7%
(NPV of revenue)	$4,658.3	$2,959.7	$3,293.9			$2,517.1	$559.0		

Source: NERA analysis.

Table A.3
Queensland: Scenario Changes in P_0

	ENERGEX	Ergon Energy	DNSP weighted average	Change
P_0 (assume X2-5 = 0)	-42.6%	-47.5%	-45.0%	
(NPV of revenue)	$5,471.9	$5,109.6		
WACC (including franking)	-23.6%	-29.7%	-26.6%	-18.4%
(NPV of revenue)	$4,933.2	$4,669.3		
Capex	-33.8%	-40.3%	-36.9%	-8.0%
(NPV of revenue)	$5,134.8	$4,858.6		
Opex	-39.9%	-39.6%	-39.8%	-5.2%
(NPV of revenue)	$5,368.8	$4,836.8		
WACC, Capex & Opex	-14.2%	-16.2%	-15.1%	-29.8%
(NPV of revenue)	$4,555.7	$4,183.9		

Source: NERA analysis.

Table A.4
South Australia: Scenario Changes in P_0

	ETSA Utilities	Change	ElectraNet	Change
P_0 (assume X2-5 = 0)	-36.4%		-33.9%	
(NPV of revenue)	$2,879.2		$1,003.8	
WACC (including franking)	-26.0%	-10.4%	-19.8%	-19.2%
(NPV of revenue)	$2,710.9		$914.7	
Capex	-25.8%	-10.6%	-25.4%	-8.5%
(NPV of revenue)	$2,655.5		$940.2	
Opex	-26.3%	-10.0%	-31.2%	-2.7%
(NPV of revenue)	$2,667.1		$983.6	
WACC, Capex & Opex	-7.8%	-28.6%	-10.3%	-28.6%
(NPV of revenue)	$2,319.4		$865.2	

Source: NERA analysis.

Table A.5
Australian Capital Territory: Scenario Changes in P_0

	ActewAGL	Change
P_0 (assume X2-5 = 0)	-22.7%	
(NPV of revenue)	$612.8	
WACC (including franking)	-23.3%	0.6%
(NPV of revenue)	$614.7	
Capex	-18.1%	-4.6%
(NPV of revenue)	$589.9	
Opex	-4.5%	-18.2%
(NPV of revenue)	$521.8	
WACC, Capex & Opex	-0.7%	-22.0%
(NPV of revenue)	$502.3	

Source: NERA analysis.

Table A.6
Tasmania: Scenario Changes in P_0

	Transend	Change
P_0 (assume X2-5 = 0)	-32.5%	
(NPV of revenue)	$778.5	
WACC (including franking)	-25.0%	-7.5%
(NPV of revenue)	$751.4	
Capex	-23.4%	-9.1%
(NPV of revenue)	$724.9	
Opex	-21.9%	-10.6%
(NPV of revenue)	$716.2	
WACC, Capex & Opex	-5.9%	-26.6%
(NPV of revenue)	$639.2	

Source: NERA analysis.

Appendix B. Key Drivers of P_0 Increase

B.1. New South Wales

Table B.1 Primary drivers of Ausgrid's Distribution P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 58.3% price increase			
1. Capex 2004/05 - 2008/09 $3.58b 2009/10 – 2013/14 $6.63b Increase $3.05b, ie, 85%	18.6%	a) Asset renewal/replacement - Increased from $1.2b to $2.9b - 56% of total increase in real capex	
		b) Augmentation to meet peak demand growth - Increased from $1.7b to $2.4b - 24% of total increase in real capex	
2. Opex	15.6%	a) Real cost scale (workload) escalation	
		b) Real cost escalation	
3. WACC	14.6%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
Unexplained change in prices = 12.2% increase			

Source: NERA analysis.

Table B.2 Primary drivers of Endeavour Energy's P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 32.9% price increase			
1. WACC	11.2%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
2. Opex	9.9%	'Base year' opex makes up 93% of allowed opex.	
3. Capex 2004/05 - 2008/09 $1.84b 2009/10 – 2013/14 $2.72b Increase $880m, ie, 48%	9.5%	a) Augmentation to meet peak demand growth - Increased from $807m to $1,101m - 33% of total increase in real capex	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $140m to $416m - 31% of total increase in real capex	i. NSW Design Planning Licence Conditions - 100% of total increase in this category - Increased from $135m to $411m
		c) Asset renewal/replacement - Increased from $521m to $781m - 30% of total increase in real capex	
Unexplained change in prices = 3.8% increase			

Source: NERA analysis.

Table B.3 Primary drivers of Essential Energy's P_0, ($June 2009)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 49.7% price increase			
1. Opex	20.2%	Inspections, maintenance & repair and vegetation management	
2. Capex 2004/05 - 2008/09 $2.24b 2009/10 – 2013/14 $3.83b Increase $1.59b, ie, 71%	15.7%	a) Augmentation to meet peak demand growth - Increased from $762m to $1,341m - 37% of total increase in real capex	
		b) Quality, reliability and security of supply enhancement - Increased from $429m to $875m - 28% of total increase in real capex	
		c) Asset renewal/replacement - Increased from $444m to $795m - 22% of total increase in real capex	
3. WACC	11.4%	Real nominal WACC increased from 6.02% to 7.60% Increase in the DRP contributes 125 basis points to the WACC Increase in the Equity risk premium contributes 38 basis points to the WACC	New benchmark higher quality than that assumed by IPART, ie, IPART assumed BBB+ to BBB 10yr Aus corporate debt. Transitional WACC allowed an equity beta of 1.0 and an MRP of 6%.
Unexplained change in prices = 4.5% increase			

Source: NERA analysis.

Table B.4 Primary drivers of TransGrid's P_0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 18.2% revenue increase			
1. Capex 2004/05 - 2008/09 $1,350 2009/10 – 2013/14 $2,405 Increase $1,055m, ie, 78%	9.4%	a) Augmentation to meet peak demand growth - Increased from $930m to $1,752m - 78% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $274m to $441m - 16% of total increase in real capex	
2. WACC	8.7%	Real post-tax WACC increased from 6.48% to 7.62%. Increase in the DRP contributes 125 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A- 10yr Aus corporate debt.
3. Opex	4.3%		
Unexplained change in revenue = 2.8% decrease			

Source: NERA analysis.

Table B.5 Primary drivers of Ausgrid's Transmission P_0, ($June 2009)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 46.8% revenue increase			
1. Capex 2004/05 - 2008/09 $402m ($'Jun09) 2009/10 – 2013/14 $1,184m ($'Jun09) Increase $783m, ie, 195%	29.9%	a) Asset renewal/replacement - Increased from $158m to $573m - 53% of total increase in real capex	
		b) Reliability and quality of service enhancement - Increased from $0m to $157m - 20% of total increase in real capex	
		c) Augmentation to meet peak demand growth - Increased from $177m to $327m - 19% of total increase in real capex	
2. WACC	16.0%	Real post-tax WACC increased from 6.48% to 7.59%. Increase in the DRP contributes 131 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A- 10yr Aus corporate debt.
3. Opex	4.9%		
Unexplained change in revenue = 3.7% increase			

Source: NERA analysis.

B.2. Queensland

Table B.6 Primary drivers of ENERGEX's P_0, ($June 2010)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 42.6% revenue increase			
1. WACC	18.9%	Real Post tax WACC increased from 5.74% to 7.25%. Increase in the DRP contributes 132 basis points to the WACC The change in Gamma added $189.5m (ie, which in itself leads to a P0 price increase by 3.7%)	**No change in the benchmark**, ie, QCA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
2. Capex <u>2005/06 - 2009/10</u> $3.22b <u>2010/11 – 2014/15</u> $5.80b <u>Increase</u> $2.59b, ie, 80%	8.8%	a) Augmentation to meet peak demand growth - Increased from $1.63b to $2.76b - 44% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $275m to $1.09b - 31% of total increase in real capex	
3. Opex	2.7%		
Unexplained change in revenue = 14.2% increase			

Source: NERA analysis.

Table B.7 Primary drivers of Ergon Energy's P_0, ($June 2010)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 47.5% revenue increase			
1. WACC	17.8%	Real Post tax WACC increased from 5.74% to 7.25%. Increase in the DRP contributes 132 basis points to the WACC The change in Gamma added $131.5m (ie, which in itself leads to a P0 price increase by 2.8%)	**No change in the benchmark**, ie, QCA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
2. Opex	7.9%	Base year opex.	Ergon noted that the "AER Decision effectively removed all step changes".
3. Capex 2005/06 - 2009/10 $3.29b 2010/11 – 2014/15 $5.11b Increase $1.82b, ie, 55%	7.2%	a) Augmentation to meet peak demand growth - Increased from $859m to $1.54b - 37% of total increase in real capex	i. Ergon stated "Significantly overspent this category in previous period and anticipated continuing level af activity in regional Qld"
		b) New customer connections (excluding customer contributions) - Increased from $858m to $1.40b - 30% of total increase in real capex	i. Ergon stated "Significantly overspent this category in previous period and anticipated continuing level af activity in regional Qld"
Unexplained change in revenue = 16.2% increase			

Source: NERA analysis.

B.3. South Australia

Table B.8 Primary drivers of ETSA Utilities' P_0, ($June 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 36.4% price increase			
1. Capex 2005/06 - 2009/10 $767m 2010/11 – 2014/15 $1,590m Increase $824m, ie, 107%	10.6%	a) Augmentation to meet peak demand growth - Increased from $204m to $615m - 50% of total increase in real capex	i. Electricity Transmission Code changes ii. Continuing peak demand growth iii. Network utilisation approaching maximum prudent limits
		b) Non-network assets - Increased from $173m to $331m - 19% of total increase in real capex	i. Renewal of major IT systems, IT support for increased network capital program, new Network Operations Centre. ii. Existing property maintenance and upgrades. To meet changing field requirements, relocation of existing depots, establishment of new offices and depots. iii. New vehicles for increases employee numbers and capital program, legislative required updates to vehicles. iv. Plant and Tools associated with new vehicles, building plant.

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
2. WACC	10.4%	Real Post tax WACC increased from 6.50% to 7.29%. Increase in the DRP contributes 86 basis points to the WACC. The change in Gamma added $162.2m in additional revenue (ie, which in itself leads to a P0 price increase by 5.8%)	**No change in the benchmark**, ie, ESCOSA assumed BBB+ 10yr Aus corporate debt Result of decision of the Tribunal to lower the gamma from 0.5 to 0.25.
3. Opex	10.0%	a) Base year - 77% of total allowed	
		b) Step changes - 20% of total allowed	i. Feed In Tariffs $39m, Asset Inspections $26m, IT support $28m, Property costs & Land Tax $21m, Insurance premiums and support $21m, Superannuation contributions $12m, Network Maintenance & Planning $14m. ii. Operating support for significant increase in capex. Note that under ETSA Utilities Cost Allocation Method (CAM), all corporate overheads are expensed.
Unexplained change in prices = 7.8% increase			

Source: NERA analysis.

Table B.9 Primary drivers of ElectraNet's P_0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 33.9% revenue increase			
1. WACC	14.1%	Real Post tax WACC increased from 6.23% to 8.07%. Increase in the DRP contributes 137 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 10yr Aus corporate debt.
2. Capex <u>2003/04- 2007/08</u> $412m <u>2008/09– 2012/13</u> $626m <u>Increase</u> $214m, ie, 52%	8.5%	a) Augmentation to meet peak demand growth - Increased from $51m to $131m - 38% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $190m to $236m - 22% of total increase in real capex	
		c) New customer connections (excluding customer contributions) - Increased from $0m to $44m - 21% of total increase in real capex	
3. Opex	2.7%		
Unexplained change in revenue = 10.3% increase			

Source: NERA analysis.

B.4. Australian Capital Territory

Table B.10 Primary drivers of ActewAGL's P_0, ($2008/09)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 22.7% price increase			
1. Opex	18.2%	Feed-in tariff and UNFT tax contributed $47.9 million ($08/09) and $10.8 million ($08/09) to the increase respectively. Specifically, step changes* contributed approximately 14% to the total allowed opex in the current regulatory period.	
2. Capex 2004/05- 2008/09 $147m 2009/10– 2013/14 $275m Increase $129m, ie, 88%	4.6%	a) Augmentation to meet peak demand growth - Increased from $9m to $75m - 50% of total increase in real capex	
		b) Asset renewal/replacement - Increased from $70m to $95m - 19% of total increase in real capex	
3. WACC	-0.6% (New allowance would decrease prices – ie, real opex has fallen between the current period and the last)	Real Post tax WACC increased from 6.36% to 6.37%. Increase in the DRP contributes 140 basis points to the WACC.	**No change in the benchmark**, ie, the ICRC assumed BBB+ 10yr Aus corporate debt.
Unexplained change in prices = 0.7% increase			

Source: NERA analysis.

** We understand from ActewAGL that there was only one major step change included in the final decision which was outside of ActewAGL's control, being the Feed-in Tariff (FiT).*

B.5. Tasmania

Table B.11 Primary drivers of Transend's P_0, ($June 2009)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 32.5% revenue increase			
1. Opex	10.6%	The allowance provided by the ACCC for the 2004-09 regulatory period was unsustainably low.	
2. Capex 2004/05- 2008/09 $334m 2009/10– 2013/14 $606m Increase $273m, ie, 82%	9.1%	a) New customer connections , to meet customer demand:[137] - Increased from $5.7m to $110m - 40% of total increase in real capex	
		b) Augmentation to meet demand growth and reliability standards - Increased from $127m to $233m - 39% of total increase in real capex	
3. WACC	7.5%	Real Post tax WACC increased from 6.55% to 7.58%. Increase in the DRP contributes 125 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 5.5yr Aus corporate debt.
Unexplained change in revenue = 5.9% increase			

Source: NERA analysis.

[137] Note that Transend has converted from an "as commissioned" recognition of capex to an "as incurred" approach, consequently, this comparison is not on a like for like basis.

B.6. Victoria

Table B.12 Primary drivers of CitiPower's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 1.4% price increase			
1. WACC	4.9%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Opex	1.2%	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 11% of total allowed opex	i. Electricity Safety (Electric Line Clearance) Regulations
3. Capex <u>2006- 2010</u> $605m <u>2011– 2015</u> $768m <u>Increase</u> $163m, ie, 27%	1.2%	a) New customer connections (excluding customer contributions) - Increased from $165m to $224m - 67% of total increase in real capex*	
		b) Augmentation to meet peak demand growth - Increased from $217m to $268m - 58% of total increase in real capex*	
Unexplained change in prices = 5.5% decrease			

*Source: NERA analysis. * Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.13 Primary drivers of Powercor's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 6.3% price increase			
1. WACC	4.1%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Opex	3.7%	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 11% of total allowed opex	i. Electricity Safety (Electric Line Clearance) Regulations
3. Capex <u>2006- 2010</u> $886m <u>2011– 2015</u> $1,324m <u>Increase</u> $438m, ie, 49%	3.4%	a) New customer connections (excluding customer contributions) - Increased from $164m to $428m - 81% of total increase in real capex*	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $92m to $231m - 43% of total increase in real capex*	
Unexplained change in prices = 4.4% decrease			

Source: NERA analysis

** Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.14 Primary drivers of Jemena's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 11% price increase			
1. WACC	6.6%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
2. Capex 2006- 2010 $333m 2011– 2015 $434m Increase $101m, ie, 30%	1.6%	a) Environmental, safety and statutory obligations (excluding reliability) - Increased from $23.6m to $80.7m - 57% of total increase in real capex*	i. Bushfire Mitigation (Poles Top Structures, Poles and Conductor Replacement) ii. Public Safety - Neutral Screen Service Replacement iii. Electric Line Clearance Regulation
		b) Augmentation to meet peak demand growth - Increased from $58m to $99m - 40% of total increase in real capex*	
3. Opex	-3.6% (New allowance would decrease prices – ie, real opex has fallen between the current period and the last)	a) Base year opex - 84% of total allowed opex	
		b) Step changes - 13% of total allowed opex	i. Changes to Electrical Safety (Management) Regulations incl Process Compliance is the single biggest contributor
Unexplained change in prices = 6.8% increase			

Source: NERA analysis.

Table B.15 Primary drivers of SP AusNet's Distribution P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 19.2% price increase			
1. Opex	9.2%	a) Base year opex - 73% of total allowed opex	
		b) Step changes - 22% of total allowed opex	i. New vegatation management regulations associated with bushfire mitigation
2. Capex <u>2006- 2010</u> $670m <u>2011– 2015</u> $1,417m <u>Increase</u> $747m, ie, 111%	6.8%	a) Augmentation to meet peak demand growth - Increased from $114m to $389m - 42% of total increase in real capex	
		b) New customer connections (excluding customer contributions) - Increased from $234m to $432m - 30% of total increase in real capex	
		c) Non-network assets - Increased from $33m to $168m - 20% of total increase in real capex	i. Change in IT and vehicles from opex (leasing) to capex (ownership)
3. WACC	6.3%	Real Post tax WACC increased from 5.97% to 7.13% Increase in the DRP contributes 153 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
Unexplained change in prices = 2.3% increase			

Source: NERA analysis.

Table B.16 Primary drivers of United Energy's P_0, ($Dec 2010)

Major contributors to P_0	Impact on real price increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 5.6% price increase			
1. Capex 2006- 2010 $624m 2011– 2015 $753m Increase $129m, ie, 21%	4.2%	a) Environmental, safety and statutory obligations - Increased from $90m to $213m - 96% of total increase in real capex*	
		b) Augmentation to meet peak demand growth - Increased from $111m to $181m - 55% of total increase in real capex*	
2. WACC	3.8%	Real Post tax WACC increased from 5.97% to 6.88% Increase in the DRP contributes 131 basis points to the WACC	**No change in the benchmark**, ie, ESC assumed BBB+ 10yr Aus corporate debt
3. Opex	2.8%	a) Base year opex - 86% of total allowed opex	
		b) Step changes - 10% of total allowed opex	
Unexplained change in prices = 4.9% decrease			

Source: NERA analysis.

** Note: the two percentages presented here exceed 100% as there was a real decrease in capex allowed for 'asset renewal/replacement'.*

Table B.17 Primary drivers of SP AusNet's Transmission P0, ($June 2008)

Major contributors to P_0	Impact on real revenue increase (in isolation)	Major categories of contribution	Drivers of each category
Decision P_0 = 15.3% revenue increase			
1. WACC	3.2%	Real Post tax WACC increased from 6.20% to 7.17%. Increase in the DRP contributes 55 basis points to the WACC.	New benchmark lower quality than that assumed by ACCC, ie, ACCC assumed A 5yr Aus corporate debt.
2. Capex 2003/04- 2007/08 $398m 2008/09– 2013/14 $771m Increase $373m, ie, 94%	3.1%	a) Asset renewal/replacement - Increased from $339m to $522m - 49% of total increase in real capex	
		b) Environmental, safety and statutory obligations (excluding reliability) - Increased from $0m to $158m - 42% of total increase in real capex	
3. Opex	1.1%		
Unexplained change in revenue = 5.5% increase			

Source: NERA analysis.

Appendix C. Real Cost Escalation Factors

The following real cost escalation factors have been developed for the ENA by SKM, for use in the current analysis.

Table C.1 Annual real cost escalators developed by SKM

Category	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Distribution Capex program	1.009	1.086	1.053	1.029	1.015	0.967	0.939	1.007	0.979	1.010	1.013	1.023	1.001	1.032	1.026
Distribution Opex program	1.010	1.029	1.021	1.017	0.999	1.010	0.991	1.004	1.001	1.008	1.013	1.017	1.011	1.020	1.021
Transmission Capex program	1.014	1.094	1.049	1.037	1.024	0.970	0.932	1.011	0.983	1.010	1.012	1.021	1.001	1.032	1.027
Transmission Opex program	1.010	1.029	1.021	1.017	0.999	1.010	0.991	1.004	1.001	1.008	1.013	1.017	1.011	1.020	1.021

Note: Escalation factors are year-on-year for the year ending in June of each year.

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Appendix B

NERA Economic Consulting Report

Rising Electricity Prices and Network Productivity: a Critique

NERA
ECONOMIC CONSULTING

Rising Electricity Prices and Network Productivity: a Critique

A report for the Energy Networks Association

16 April 2012

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Contents

Executive Summary

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Energy Networks Association. It provides a critique of the following two reports, prepared by Bruce Mountain on behalf of the Energy Users Association of Australia:

- *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* 'Mountain (2011)' published in May 2011;[1] and
- *Electricity Prices in Australia: an International Comparison* 'Mountain (2012)' published in March 2012.[2]

Following a review of the expenditure allowances of distribution network service providers (DNSPs), Mountain (2011) concludes that regulatory failure and government ownership are the major causes of recent increases in the price of electricity distribution, rather than the oft cited need for investment to replace aging assets and meet the requirements of rising peak demand. On this basis, Mountain makes a number of recommendations that, the paper argues, would raise productivity in this sector.

Our assessment of the analysis undertaken in Mountain strongly suggests that it provides an insufficient basis for such conclusions. Failure to consider the many legitimate reasons for variances in costs and a reliance on inappropriate comparisons has resulted in Mountain drawing unsubstantiated conclusions about the relative efficiency of DNSPs. Mountain's focus on ownership as the key distinction between DNSPs omits consideration of state-specific cost drivers. Identification of actual cost drivers is further hampered by Mountain's use of state averages rather than reviewing data on a DNSP specific basis.

Mountain begins by comparing revenue, capital expenditure (capex) and the value of the regulatory asset base (RAB) per connection within each state, on a weighted average basis. The paper notes that growth in each of these ratios has been substantially higher for DNSPs in Queensland and New South Wales as opposed to South Australia and Victoria. Mountain consequently concludes that the financial performance of government-owned DNSPs, being those in Queensland and New South Wales, is relatively poor compared to that of the privately-owned DNSPs, being those in South Australia and Victoria.

A comparison of these ratios is ill-suited to making conclusions regarding the relative efficiency of DNSPs. There are numerous reasons, besides relative efficiency, why DNSPs may have different levels of operating expenditure (opex) and capex, and different RAB values per connection. These may include service quality standards, past expenditure decisions and the nature of the network, such as the mix between industrial and residential connections, network length, customer density, peak and average demand levels, the split between transmission and distribution networks.

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1 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.

2 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

Furthermore, the use of averages for each state masks variations in costs between firms *within* each state. Such a loss of information makes it difficult to draw any robust conclusions about the true causes of cost differences.

Mountain (2011) then develops a composite scale variable (CSV) to assess the relative efficiency of DNSPs. In essence, this analysis assumes that customer numbers and network length are the only drivers of DNSP costs. In our opinion, this is not a reasonable assumption, since it overlooks the many other potential sources of cost differentials. His approach therefore does not provide a sound basis upon which to draw any conclusions about the relative efficiency of businesses.

There are likewise many shortcomings contained in Mountain's comparison of the costs of NEM distributors and the costs of businesses located in Great Britain. First, there are a number of intrinsic difficulties associated with making international comparisons that can reduce the explanatory power of such analyses, including:

- the use of different exchange rates can greatly affect the results;
- government policies can affect prices; and
- regulatory and accounting differences between jurisdictions can mean that costs are not directly comparable, ie, one may not be comparing 'like with like'.

Second, there are many reasons for prices differing across countries that have nothing to do with the relative efficiency of the businesses in each location. For example:

- there may be many differences in the characteristics of the networks being considered such as the line length and the level and growth in peak demand;
- there may be distortions in the current prices due to past regulatory decisions; and
- there may be jurisdictional differences in the cost of inputs, eg, cost of capital, labour and materials costs may vary significantly across geographies.

Mountain reviews a number of potential cost drivers that may have been responsible for recent price increases in Australia. In our view, a number of conspicuous deficiencies in Mountain's analysis mean that one cannot reasonably conclude that government ownership and the regulatory framework are the key drivers of price increases. In particular, Mountain:

- dismisses rising peak demand as a driver of investment by reference to the growth in *historic aggregate* and *average* demand. These metrics are not relevant, since networks must be configured to meet *anticipated peak* demand, not past average demand. It is clear that peak demand is expected to grow considerably in some states and this will naturally precipitate additional investment that will need to be remunerated through price increases;
- rules out the need to replace aging assets as a driver of investment by considering the average effective remaining life of assets. However, this measure is not informative of the value of assets that need replacing at any one time since DNSPs' assets will have different age profiles;
- dismisses claims that there is an element of 'catch-up' in investment due to past levels of under-investment, largely on the basis of reports suggesting the DNSPs could become more efficient and reduce their operating costs, which is of highly questionable relevance.

In our opinion, the analysis provided in the NERA report, *Analysis of Key Drivers of Network Price Changes* provides a significantly better basis for determining the actual cost drivers that have led to the recent price increases.[3] By way of brief summary, that report concludes that the key drivers of price changes have been:

- increases in the allowed WACC;
- increases in the capex allowance; and
- increases in the allowed opex.

Moreover, in each case the reasons for the increase were external drivers such as an increase in the measured debt risk premium, ageing assets and new statutory obligations such as feed-in tariffs, rather than reflecting a shortcoming in the Rules.

Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison*, was not submitted to the AEMC as part of the review of the NER. However, the timing of its release makes it likely the paper will receive some attention in the course of this review.

Mountain (2012) provides an international comparison of electricity retail prices. On the basis of this comparison, Mountain concludes that Australian prices are high and rising when compared to those in other countries. Because the report considers *retail* prices – and only for household customers – rather than the costs of DNSPs, it has little if any relevance for the AEMC process.

Moreover, the paper exhibits a number of shortcomings. The choice of the exchange rate has a significant impact on the results. Mountain has largely focused on market exchange rate based comparisons, and it is on the basis of these prices that Mountain draws his conclusions. However, the purchasing power parity based comparisons that Mountain presents show a substantially narrower gap between retail prices in Australia and overseas. In fact, on this basis, Mountain finds that Australian prices are actually lower than those in Japan and the EU. The overseas data is also older, further reducing the relevance of the comparison. Finally, we note that Mountain's conclusions are inconsistent with those reached by a number of other commentators.[4]

It must be borne in mind that many factors may result in differences in retail prices including government policies, how electricity is generated and geographical and meteorological factors. In short, even if Mountain's analysis did establish that retail prices in Australia were higher (which it does not), there are many potential explanations unrelated to efficiency.

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3 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

4 See section 4 below.

1. Introduction

This report has been prepared by NERA Economic Consulting (NERA) at the request of the Energy Networks Association (ENA). The ENA has asked us to review and comment on the following two reports, prepared by Bruce Mountain on behalf of the Energy Users Association of Australia (EUAA):

- *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* (hereafter referred to as 'Mountain (2011)') published in May 2011;[5] and
- *Electricity Prices in Australia: an International Comparison* (hereafter referred to as 'Mountain (2012)') published in March 2012.[6]

Mountain (2011) seeks to identify the cause of the significant recent cost increases for distribution network service providers (DNSPs) throughout Australia. The EUAA relies on the material in Mountain (2011) to support the following points in its submission to the Australian Energy Market Commission (AEMC) on the rule change proposals for the economic regulation of network services:[7]

> '[r]ising demand, ageing assets and historic underinvestment has been blamed, mainly by NSPs but also at times by regulators and governments, for significantly higher expenditure and prices. But closer analysis suggests that these are not adequate explanations… the explanation for rising expenditure is not exogenous factors such as ageing assets and demand growth but rather *the differing efficiency of the distributors in managing these factors*'[8] (emphasis added)
>
> 'Comparative benchmarking shows that the efficiency of government-owned distributors has declined significantly relative to their privately owned peers over the course of the three regulatory control periods that have applied to these distributors, so that government-owned distributors are now on average half as efficient as their privately owned peers.'[9]

The AEMC's Directions Paper notes that the analysis and findings of cost inefficiency presented in Mountain (2011) have not been rebutted.

Mountain (2012) provides a comparison of international retail electricity prices and concludes that Australian electricity prices have risen sharply in the recent past and are now higher than those in Japan, the EU, the US and Canada. This report has not been submitted to the AEMC as part of the review of the NER and it has not been relied upon in submissions to

5 Mountain, B.R., *Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors*, May 2011.

6 Mountain, B.R., *Electricity Prices in Australia: an International Comparison*, CME, March 2012.

7 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011.

8 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011, pp.i-ii.

9 EUAA, *Submission to the Australian Energy Market Commission on the Rule Change Proposals for the Economic Regulation of Network Services*, December 2011, p.ii.

the AEMC. However, it may receive some attention in the AEMC's review given the timing of its publication.

The ENA has therefore commissioned NERA to review the two papers prepared by Mountain and to opine upon the robustness of the analysis and conclusions.

The remainder of our report is structured as follows:

- section two provides our review of section three in Mountain (2011) which presents comparisons of revenues, expenditure, service levels and efficiency of DNSPs in Victoria, New South Wales, Queensland and South Australia;
- section three contains our analysis of section four in Mountain (2011) which discusses a number of potential reasons for the differences in revenues, expenditure, service levels and efficiency of DNSPs; and
- section four reviews Mountain's more recent paper (Mountain (2012)), which compares retail electricity prices in various countries.

2. Mountain (2011): Outcomes

This section provides our critique of section three of Mountain (2011). We use the same heading titles as that report and review each sub-section in turn. We proceed by first summarising Mountain's key findings, then reviewing the analysis underpinning those findings and their attendant robustness.

Section three of Mountain (2011) purports to assess the relative performance of DNSPs and to determine whether or not there is 'an efficiency issue that merits attention'.[10] The section presents comparisons of revenues, expenditure, service levels and Mountain's measure of efficiency. On the basis of these comparisons, Mountain concludes that:

- revenues collected by government owned DNSPs in New South Wales and Queensland have grown far faster than the privately owned DNSPs in Victoria and South Australia;[11]
- the main reason for this difference is increased returns on and of assets;[12]
- the regulated asset base is growing much more quickly for government owned distributors because their capitalised expenditure is around four times higher per connection compared to their privately owned peers;[13] and
- government owned distributors are, on average, half as efficient as the privately owned distributors.[14]

2.1. Comparison of revenue, expenditure, assets and service performance

2.1.1. Summary of Mountain's analysis

Mountain (2011) shows that the average allowed revenue per connection has been significantly greater for DNSPs in New South Wales and Queensland than those in South Australia and Victoria since around 2009.[15] The timing of this increase correlates with the beginning of the current regulatory period.

DNSPs in New South Wales and Queensland are government owned. Their counterparts in South Australia and Victoria are privately owned. In other words, since 2010, average allowed revenue per connection has been significantly greater in government owned DNSPs – in both metropolitan and country areas.

Mountain (2011) finds that government owned DNSPs have had consistently higher opex per connection since 2002 but there has been no recent significant change in the gap between the

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10 Mountain (2011), p.25.

11 Mountain (2011), p.v.

12 Mountain (2011), p.v.

13 Mountain (2011), p.vi.

14 Mountain (2011), p.vi.

15 Mountain (2011), p.25.

government and privately owned DNSPs. He contends that the reason for the change in allowed revenue per connection around 2010 is the proportionately greater increase in the capitalised expenditure per connection of government owned DNSPs.

Mountain attempts to assess whether lower revenues in some states are associated with a ‘degradation in service performance’.[16] This is assessed by examining the average level of service interruption frequency and duration of interruption for each state from 2001 to 2009. Mountain concludes that the average performance of privately owned DNSPs in relation to both metrics is superior to their government owned counterparts.

2.1.2. Review

Mountain (2011) draws two principal conclusions from the analysis described above:[17]

- that a comparison of revenues and expenditures shows some businesses have performed better than others; and
- that the ‘superior financial performance’ of South Australian and Victorian DNSPs has not been at the expense of poorer service performance.

Mountain (2011) has demonstrated that costs per customer have increased more rapidly in NSW and Queensland compared to South Australia and Victoria, and that the most significant cause of this rapid increase has been related to capex rather than opex. However, in our opinion, this does not constitute a sufficient basis from which to draw any reasonably inferences or conclusions about the comparative performance of DNSPs.

Although Mountain has adjusted the costs of each firm to account for differences in customer bases (by using average revenue and capex per connection), this is not sufficient to produce a comparable metric capable of revealing any information about relative efficiency. The reason for this is that there are a multitude of reasons why DNSPs may have different levels of opex and capex per connection. Some differences may relate to factors DNSPs can control, and others may not. For example, cost differences may arise due to:

- service quality standards;
- past expenditure decisions;
- differences in the boundaries between transmission and distribution companies in the various states;
- the different accounting methodologies that DNSPs may employ;
- the mix between industrial and residential connections;
- network length;
- customer density;
- labour costs;
- the proportion of the network that is underground;

16 Mountain (2011), p.28.

17 Mountain (2011), p 28.

- peak and average demand levels;
- the occurrence of floods, fires and other natural phenomena that can damage distribution wires;
- the climate and terrain;
- transformer capacity; and
- transmission losses.

It is likely that all these factors affect the data underpinning the conclusions set out in in Mountain (2011).[18] It follows that those conclusions cannot be relied upon, absent a more fulsome analysis that takes account of these alternative potential explanations for differences across firms. Furthermore the use of an average revenue figure for each state masks variations in costs between firms in the same state, and represents another reason why the analysis cannot be relied upon to reveal any meaningful information about the efficiency performance of businesses.

Mountain reviews the difference in quality of service provided by DNSPs to assess whether the lower cost of service in Victoria and South Australia has led to poorer service standards. On the basis of the *averages from 2001 to 2009* of the System Average Interruption Frequency and the System Average Interruption Duration Indices, Mountain concludes that service performance in Victoria and South Australia has been *slightly better* than in New South Wales and Queensland. There are a number of problems with this analysis.

First, the relevance of the data itself is questionable. Mountain (2011) is largely concerned with price increases that have occurred *since 2009*, yet his data corresponds to an *earlier period*.

Second, Mountain uses nine year averages, rather than presenting the time series on an annual basis. For example, consideration of the underlying series over this period shows an increase in the total length of interruptions in Victoria, where expenditure per connection has been low, and a decrease in the number and total length of interruptions in New South Wales, where expenditure per connection has been high.[19]

Notwithstanding this, any consideration of measures of quality is fraught with complications and Mountain's simple comparison fails to account for many of the quality dimensions that are important to network users or the numerous factors that influence service levels but are beyond the control of DNSPs, eg, electrical storms, flooding and fires. In a recent report, the AER explained that:[20]

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[18] Given the large number of potential causes of different costs of electricity distribution, it is not surprising that electricity prices vary across states and countries. For example, there is a wide variation in EU electricity prices, see Mountain (2012), p.11.

[19] The average number of interruptions (and their total length) in New South Wales for the first half of the decade was 1.94 (238 minutes) per year and for the second half of the decade it was 1.74 (186 minutes) per year. In Victoria, average number of interruptions (and their total length) for the first half of the decade was 1.98 (152 minutes) per year and for the second half of the decade it was 1.98 (203 minutes) per year. Source: AER, *State of the Energy Market*, December 2011, p.68.

[20] AER, *State of the Energy Market*, December 2011, p.68.

> ‘[a] number of issues limit the validity of comparing reliability data across jurisdictions. In particular, the data rely on the accuracy of the businesses’ information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.’

The AER has also stated that ‘Queensland experiences significant variations in performance partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.’[21] It added that that ‘an assessment of network performance should normalise data to exclude interruption sources beyond the network’s reasonable control.’[22]

In our opinion, Mountain (2011)’s service quality analysis provides an insufficient basis to support any conclusions relating expenditure levels to service performance. In particular, it is incapable of enabling any conclusion to be reached as to whether the cost increases in Queensland and New South Wales *since 2009* have been inefficient.

In sum, the analysis contained in the ‘Comparison of revenue, expenditure, assets and service performance’ section of Mountain (2011) cannot be relied upon to reach any conclusions about the relative efficiency of DNSPs. Mountain himself acknowledges this to a limited degree, when he states in the following section:[23]

> ‘[t]he results presented in this section so far are the ratios of the revenues or expenditures relative to customer numbers. These ratios are strongly suggestive of differences in efficiency. But it is not possible to draw categorical conclusions from this on the relative efficiency of the distributors.’

Put simply, because Mountain does not consider the many other potential, legitimate reasons for cost differences across firms, he risks drawing erroneous inferences and conclusions.

2.2. Efficiency benchmarking using statistical regressions

2.2.1. Summary of Mountain’s analysis

Mountain sets out an explanation of his efficiency benchmarking analysis in Appendix A. His methodology involves the derivation of a ‘composite scale variable’ (CSV) for each firm, which he then uses to arrive at an estimate of the expenditure levels each firm should theoretically be incurring. Those hypothetical levels are then compared to each firm’s actual expenditures to ascertain whether they are over or under spending.

Mountain then ranks the firms according to their performance against the hypothetical cost benchmarks. His ‘efficiency frontier’ is defined such that 25 per cent of firms are considered to be ‘efficient’ and the remaining 75 are deemed to be ‘inefficient’.

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21 AER, *State of the Energy Market*, December 2011, pp.68-69.

22 AER, *State of the Energy Market*, December 2011, p.68.

23 Mountain (2011), p.30.

2.2.2. Review

Although benchmarking can be a useful tool, if it is done improperly or interpreted without sufficient care, it can lead to erroneous conclusions. In particular, Mountain himself emphasises the importance of undertaking benchmarking analysis using accepted econometric or statistical techniques. In our opinion, the analysis he has undertaken has not met this standard.

In essence, the regression analysis undertaken as part of Mountain's CSV methodology has done no more than consider the extent to which customer numbers and network length explain costs. While this is a step forward from the use of average costs per connection, as used in the previous section, it still fails to account for a great number of the other variables discussed in section **Error! Reference source not found.** that can also influence DNSP's costs. It follows that the analysis described above is again an insufficient basis to reach any conclusions about the relative efficiency of firms.

Appendix A indicates that Mountain realised other variables would be likely to impact costs but statistical limitations precluded their inclusion in his analysis. In particular, although Mountain considered including 'energy distributed' and 'peak demand' in his analysis he chose not to. He reasoned that due to the close relationship between customer numbers, energy distributed and peak demand meant that including only customer numbers would suffice.

We disagree. Omitting potentially relevant variables in this manner will often create more problems than it solves.[24] It is interesting to note that Mountain and Littlechild (2010) included three variables in their equivalent CSV exercise. In any event, as we noted above, even if Mountain had included all four variables in the CSV analysis, this still would not have been sufficient to account for all of the potentially relevant cost drivers.

Furthermore, even if one could reasonably consider customer numbers and network length as being the only relevant variables driving a company's costs (a proposition we consider entirely unreasonable), it is not clear whether Mountain's analysis of the CSV would be appropriate given that:

- he does not adjust for the 'lumpy' nature of capex, ie, under his analysis, a firm may appear inefficient if it has recently invested in a large capital project with a long life, even though this investment may be prudent and efficient;
- Mountain has assumed that expenditure should be a linear combination of customer numbers and network length, which leads to the improbable result that there would be no economies of scale as a network increases in size. There does not appear to be any justification for such a restriction;
- the intercept of the regression has been constrained to zero by Mountain, implying that a DNSP without customers or network length would have zero costs. This assumes that the DNSP would have no fixed costs, and consequently fails to take into account factors such as the cost of a management team and the cost of infrastructure that is unrelated to scale. This constraint appears to have been chosen to avoid a negative intercept, which would

[24] O'Brien, R. M., *A Caution Regarding Rules of Thumb for Variance Inflation Factors*, Quality & Quantity, 2007.

imply negative fixed costs for a DNSP. In our view, the fact that Mountain's model returns a negative intercept without this constraint strongly suggests that the model has been misspecified;

- Mountain does not report any statistical tests, or even the relative weights of the variables in the CSV. Such test results are important in assessing the robustness and explanatory power of the regression, and consequently the accuracy and reliability of its results;
- it is not clear whether the costs considered are opex or total expenditure (ie, the sum of opex and capex) since appendix A seems to use the terms opex and total expenditure interchangeably. It follows that:
  - if total expenditure has been used, it is not clear why Mountain developed the CSV since the first and second steps of the analysis could usefully be compressed into one step without any effect on the results; or
  - on the other hand, if Mountain has used opex as the explanatory variable, then his analysis sheds even less light on relative performance as Mountain has suggested it is capex rather than opex that is the main contributor to the difference in performance between DNSPs.

For a benchmarking exercise to be informative it should, as far as possible, control for all differences in operating conditions between firms. However, Mountain's analysis controls only for customer numbers and network length. There are many other factors that could, and should, be taken into account. Furthermore, the paper provides no statistical evidence to indicate how much of the DNSPs' costs are explained by these variables. It would therefore be imprudent to accept the conclusions that Mountain draws from his analysis.

Ofgem has used a CSV in the past to assess the efficiency of electricity distributors.[25] However, it no longer relies on the use of a CSV in its measurement of efficiency. In its most recent electricity distribution price review for the years 2010 to 2015, it used a much more granular and robust analysis that included a number of different models, methods and estimation techniques. These included, without limitation:

- the use of linear and non-linear models;
- the use a variety of techniques to ensure outcomes are not skewed by any one particular approach;[26]
- inclusion of a variety of variables to explain cost differences between DNSPs;
- the comparison of a subset of DNSPs' costs since only some of the costs are comparable;[27]
- a series of statistical tests to assess the robustness and explanatory power of the models;[28]
- a wide range of different cost drivers in the models; and[29]

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25 See the following review of Ofgem's use of a CSV: CEPA, *Background to Work on Assessing Efficiency for the 2005 Distribution Price Control Review*, September 2003.

26 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.42.

27 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.39.

28 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009 – Appendix 5, pp.18-21.

- adjustments to costs to make them comparable.[30]

Mountain (2011) has not applied any of the techniques or methods listed above. It follows that the analysis is significantly less robust than might otherwise be the case if the best available techniques had been employed. This is further demonstrated by the fact that using the simple CSV approach can lead to substantially different results than if a more detailed analysis was undertaken. For example, Ofgem has shown that the detailed analysis it conducted for its most recent electricity distribution price review led to different results to those under the CSV approach that it had previously employed.[31]

The results from even a well specified benchmarking exercise would need to be interpreted with care before concluding that one DNSP was necessarily inefficient compared to others. Rather than indicating 'inefficiency', relatively high expenditure may be due to the specific circumstances of a DNSP that the model was unable to account for. Analysis similar to that undertaken in the NERA report, *Analysis of Key Drivers of Network Price Changes,* would be important in informing such an assessment.[32]

2.3. Comparing NEM distributors to those in Great Britain

In Section 3.3, Mountain provides a comparison of allowed revenues per connection for DNSPs in New South Wales, Queensland, South Australia and Victoria with those of Great Britain. The values for Great Britain are taken from Mountain and Littlechild (2010).[33] The comparison indicates that:

- the revenues per connection have been much lower in Great Britain than in Australia; and
- revenues per connection in South Australia, Queensland and New South Wales have been increasing more rapidly since around 2009.

Conducting international comparisons is not as simple as it might appear, and there are a number of reasons why caution should be employed when considering Mountain's analysis. This is explicitly acknowledged in Mountain and Littlechild (2010) which states:[34]

> '[i]t is hoped that our preliminary findings will encourage further and more rigorous analysis in order to shed more light on these important issues.'

First, one must be careful when converting prices from one currency to another since the exchange rate can have a substantial effect on relative electricity prices. The Australian dollar has risen from around 0.4 pounds to the dollar at the beginning of 2007, to 0.68 pounds to the dollar in early 2012. This means that the price of electricity will appear to be over 50 per cent

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29 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.43.

30 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009, p.44.

31 Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009 – Appendix 5, p.15.

32 NERA, *Analysis of Key Drivers of Network Price Changes,* April 2012.

33 Mountain, B., Littlechild, S., *Comparing electricity distribution network revenues and costs in New South Wales, Great Britain and Victoria*, Energy Policy, September 2010 (hereafter, 'Mountain and Littlechild (2010)').

34 Mountain and Littlechild (2010), p.5771.

higher in Australia relative to the UK in early 2012 compared to 2007, purely on the basis of movements in the exchange rate.

We note that Mountain has used *market* exchange rates to conduct his analysis, which is not standard practice when comparing costs across countries. The more generally accepted approach is to use a measure of purchasing power parity (PPP), which adjusts for the 'buying power' of the currency in each country. The OECD estimated that the PPP exchange rate was one pound to 2.35 Australian dollars in 2011.[35,36] This means that the same basket of goods could be purchased for one pound in Britain or $2.35 in Australia. This contrasts to Mountain's use of a market exchange rate of $1.59 to the pound. If one were to use the PPP exchange rate rather than the market exchange rate, it would result in estimates of the revenues for Great Britain that are 37 per cent higher than those presented by Mountain from 2011.

A second complication arising in international comparisons is the need to ensure that the data really is comparable. In this regard, it is particularly important to consider whether the cost information from DNSPs in Great Britain and Australia cover the same categories, and are compiled using equivalent accounting methods. It is unclear whether this is the case; for instance, we understand that in 1999 Ofgem cut back the scope of operating expenses attributed to the distribution businesses.[37] In addition, it is not evident that the split between transmission, distribution and retail functions is the same across the two jurisdictions. If the Australian DNSPs include different categories of costs, or have different accounting methods, these differences should be taken into account when making any comparisons with the distribution businesses in Great Britain.

In addition to this, comparisons of prices over a short time period (relative to asset lives) should be treated with caution. There may be factors that distort prices within a given time period, such as regulatory decisions that affect prices in a way that is inconsistent with the underlying costs of the DNSP. For instance, we understand that in England and Wales, the regulatory asset value of pre-vesting assets was set equal to the market value of the company at privatisation. These asset values are substantially lower than the modern equivalent asset value of the assets. We also understand that the depreciation of the pre-vesting regulatory asset values was accelerated. The life of pre-vesting assets was only 11-16 years from 1990. Depreciation on pre-vesting assets was therefore coming to an end during the 2000-05 period for some companies, and the 2005-10 period for others. Accelerated depreciation reduced accounting costs but led to cash flow problems such that Ofgem accelerated the depreciation on post-vesting assets as well. This reduced revenues for 2000-2010 due to the rapid fall in asset values. Costs and revenues for DNSPs are now rising due to an increase in capital expenditure required to maintain or replace existing assets. Indeed, Ofgem's final proposals of December 2009 show that a substantial increase in revenue is required for all but one company.[38]

35 Source: PPP for GDP, OECD 2011.

36 See Tables 1.2 and 1.12, *2008 PPP Benchmark results*, OECD. Available at < http://www.oecd-ilibrary.org/statistics>.

37 Ofgem, *Distribution Price Control Review: Draft proposals*, August 1999, Tables 1-14.

38 Ofgem, *Electricity Distribution Price Control Review Final Proposals*, Ref 144/09, December 2009, pp.33-34.

We also understand that between 2000 and 2005, British companies deferred necessary capital expenditure by extending the asset lives of their existing assets. As a result of this, several companies have increased their capital expenditure for asset replacement since 2005, and it is expected that forecast investment will continue to grow strongly.[39] However, this will not be fully reflected in the comparison provided in Mountain (2011) since the capital expenditure is likely to affect revenues over a longer period than the next few years.

There are also many legitimate reasons for the differences in allowed revenues per connection in Britain and Australia. These reasons are largely similar to those discussed in relation to the cost differences between DNSPs in different states. For this reason, international comparisons usually try to compare areas that have as few differences as possible. For example, Ofgem only included the north eastern states of the US in its comparison of DNSPs in the US and UK since those states are thought to have similar weather conditions to the UK.[40] Mountain (2011) does not appear to have done this, which raises further questions over the reliability of his results given that weather patterns are very different in Australia and the UK.

Differences in the level of peak demand and average network length between Britain and Australia may also assist in explaining why allowed revenues per connection differ between these jurisdictions. For example:

- the average network length per 1,000 customers is 84km in New South Wales, 61km in Victoria and 27km in the UK;[41] and
- peak demand in Australia, driven by heavy demand for air-conditioning, is substantially higher than in the UK. The average peak demand in the UK is around 2.1MW per 1000 customers, whereas in New South Wales it is 3.53, and in Victoria 3.28.[42]

Compared with the UK, electricity networks in New South Wales therefore have more than three times as much network length per customer, and must serve about 70 per cent more peak demand per customer. These factors alone would explain a substantially higher cost per customer in New South Wales than in Great Britain, even if everything else was equal.

It is also likely that there will be significant differences in the cost of inputs between the UK and Australia. Mountain and Littlechild (2010) dismiss differences in input costs as a factor in explaining variations in revenues per connection. For example, they explain that:

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[39] Ofgem, *Electricity Distribution Price Control Review: Final Proposals - Allowed revenue,* Cost assessment appendix, 146a/09, December 2009, Table 9 – General reinforcement – Final Baseline, Table 12 Final Baseline Fault Levels, Table 13 Final Baseline – Asset Replacement.

[40] Ofgem, *Electricity Distribution Price Control Review Methodology and Initial Results Paper,* May 2009 – Appendix 5, p.16.

[41] AER, *State of the Energy Market*, 2011, page 56; and Ofgem, *Electricity Distribution Annual Report* 2010-11, Supporting Data File entitled "ED_Annual_Report_2010_11_data_public.xlsm", available at <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=702&refer=Networks/ElecDist/PriceCntrls/DPCR5>.

[42] AER, State of the Energy Market, 2011, p.56; Nationalgrid website, <http://www.nationalgrid.com/uk/Electricity/MajorProjects/EnergyChallenge.htm>; and Ofgem, Electricity Distribution Annual Report 2010-11, Supporting Data File entitled "ED_Annual_Report_2010_11_data_public.xlsm", see <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=702&refer=Networks/ElecDist/PriceCntrls/DPCR5>.

> 'most capital items employed by distributors (transformers, switchgear, lines and cables) are internationally traded and therefore, if effectively procured, should cost much the same in New South Wales and GB.'[43]

However, this ignores the transport cost for these capital items, importation and other regulatory charges, economies of scale from selling more items in Europe and potentially the greater buyer power of European firms who may purchase more than Australian firms. Furthermore, the assets are long lived and exchange rate movements will distort the comparisons between revenues that are, at least in part, based on historic cost information.

The differences in costs between the UK and Australia may also be due to legitimate difference in the rates of returns between the countries. Mountain and Littlechild (2010) noted that the single biggest driver of the cost divergence was the rate of return regulators in Australia allowed DNSPs compared to regulators in the UK. This is the case and is related to a number of legitimate reasons rather than an inherent inability of the regulator to constrain prices. This is discussed in greater detail in section 3.6.

In conclusion, the results of the comparison in Mountain (2011) could be caused by a range of factors, including exchange rate movements, differences in cost categories and accounting practices, variations in the definition of 'distribution', short term variations in expenditure and the many differences between distribution networks in the UK and Australia. Therefore, it is not clear what conclusions, if any, can be drawn from the comparisons in Mountain (2011).

[43] Mountain and Littlechild (2010) p.5773.

3. Mountain (2011): Possible Explanations for Rising Prices and Declining Productivity

In the preceding section, we explained that Mountain concluded DNSP costs have been rising rapidly in Queensland and New South Wales and that these increases have largely been due to capital expenditures, rather than operating costs. Regulators and DNSPs have put forward a number of reasons to explain these increases. In this section, Mountain considers a number of these explanations in turn.

In our opinion, the main problems with the analysis in this section of Mountain (2011) are that:

- each explanation is considered individually rather than collectively. In practice, many variables are likely to have an effect on the level of expenditure of DNSPs at the same time. A multiple regression analysis would be preferable as it would allow a number of variables to have an effect on expenditure simultaneously; and
- the analysis of each explanation is insufficient and inconclusive.

3.1. Rising peak demand

Mountain shows that the average annual growth rate in demand has recently been greatest in Victoria, whilst being slightly lower in New South Wales and Queensland and much lower in South Australia. Mountain finds that growth related expenditure (per connection or per MW of additional demand) is higher in New South Wales and Queensland than in the other two states.

Thus Mountain concludes that '[d]emand related expenditure has been poorly correlated to demand growth'[44] and states:[45]

> 'growth-related expenditure allowed by the AER has been four times higher per connection for government owned distributors in New South Wales and Queensland than for privately owned distributors in Victoria and South Australia. This suggests the main issue seems to be an inefficient response to demand growth by government owned distributors, sanctioned by the regulator.'

The relevant consideration for DNSPs when considering investment needs is *future peak demand*. It is peak, and not average demand, that is the key determinant of how a distribution network is constructed or upgraded. However, Mountain presents *historic* information on *average demand per customer* and *total demand*. This information has no obvious bearing on the increases in capital expenditure experienced from 2009.

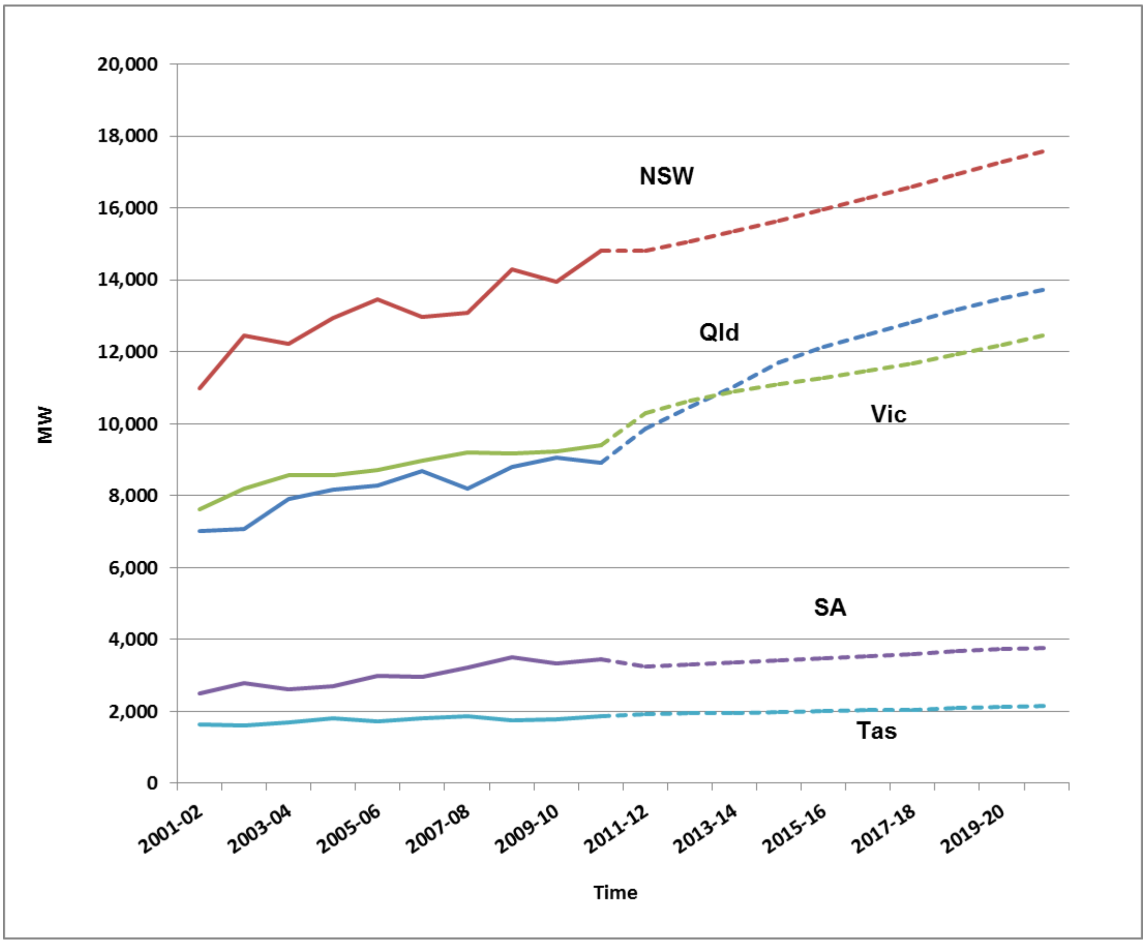
Figure 3.1 below shows how the level of total peak demand has changed, and is expected to change, across New South Wales, Queensland, Victoria, South Australia and Tasmania.

[44] Mountain (2011), p.57.

[45] Mountain (2011), p.vi.

Maximum demand is expected to be highest and growing most rapidly in New South Wales and Queensland from around 2012/2013.

Figure 3.1
Growth in maximum demand in the NEM



Source: AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.11.

The AER has said that: '[o]verall maximum demand for energy in Queensland is expected to grow at around twice the rate of growth of customer numbers over the period 2010–2015.'[46] Thus substantial investment may be needed to meet this higher peak demand. Similarly, the AER has explained that peak demand is expected to grow in New South Wales and that this will require investment expenditure:

> '[m]aximum demand growth in New South Wales is projected to increase by between 2.7 per cent and 3.5 per cent a year between 2010/11 and 2013/14 (depending on the distribution area). Demand growth is expected to be highest in Endeavour Energy's distribution area, due to higher and more sustained peak temperatures in south and western Sydney, and the high uptake of air conditioners across its network. This trend is resulting in an overall shift towards higher maximum demand in summer compared

46 AER, *Queensland distribution determination 2010-11 to 2014-15*, Final decision, p.vi.

> to winter in New South Wales. As a result, significant increases in capital works are required to ensure this projected growth in maximum demand can be met.'[47]

Our sister report[48] also demonstrates that, for some DNSPs, rising peak demand explains a substantial part of the recent increases in capex. For example, augmentation to meet peak demand growth contributed 24 per cent of the total increase in the real capex allowance for Ausgrid and 37 per cent for Essential Energy – both of which are in New South Wales.[49]

Even so, there are reasons why peak-demand related investment may not be perfectly correlated with anticipated peak demand growth at any point in time. For example there may have been capacity to deal with rising peak demand in some of these networks without needing higher levels of investment. This will depend on past investments and the nature of the network. It may also be the case that the cost of investment differs across states for legitimate reasons. This could be due to, for example, different standards, topology, levels of underground cabling, customer density, location of new customers relative to existing customers, wages and the cost of land. Therefore, a consideration of the level of peak demand growth on its own is insufficient to understand what expenditure may be needed as a result.

In summary, we do not consider the analysis undertaken in Mountain (2011) provides sufficient basis to discredit the claim that growth in peak demand has been a key driver of capex.

3.2. Ageing assets

Mountain finds that the per connection allowances to replace aging assets has been nearly four times higher in New South Wales and Queensland compared to Victoria and South Australia.[50] Mountain also finds that the DNSPs in New South Wales and Queensland had, on average, longer remaining asset lives than those in South Australia and Victoria. The average remaining asset life was estimated by weighting the remaining asset life in each asset class by the value of the assets in that class. On this basis, Mountain suggests that government-owned DNSPs have been given inappropriately high allowances by the AER.

The average remaining life of a DNSP's assets is only of limited relevance because the key driver of investment will be the extent to which assets are retired at any point in time. A comparison of average asset lives will not provide information on the extent to which assets need replacing if the age profile of assets differs between DNSPs.

For example, two networks will have the same average remaining asset life if one has all of its assets with a remaining life of 20 years and the other has half of its assets with a remaining life of one year and the other half with a remaining life of thirty nine years. However, the implied investment profile for these two DNSPs will look vastly different. Mountain argues

47 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.31.

48 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

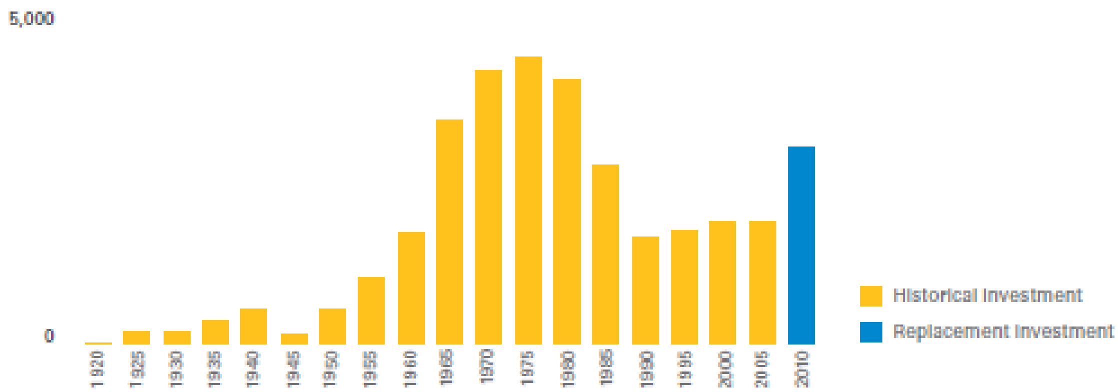
49 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

50 It is unclear over what period Mountain makes this comparison. We assume that it is a comparison of recent data.

that there is 'no reason to believe that such an asymmetry exists'.[51] On the contrary, Figures 3.2 to 3.4 suggest that the age profile of DNSPs are far from identical, for example:

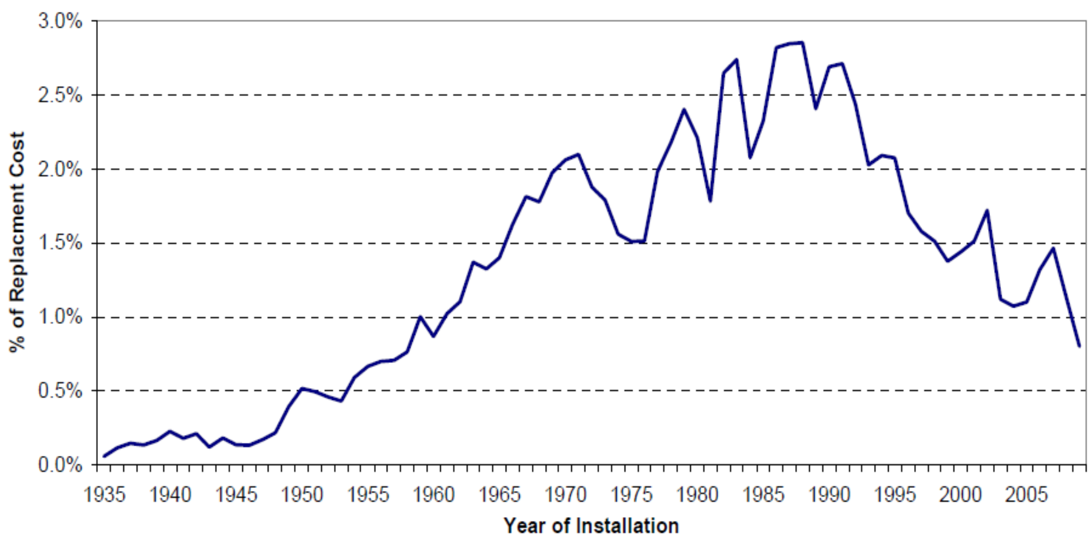
- Ausgrid has a peak in the value of assets built in the 1970's and early 1980s followed by a significant fall in the late 1980's;
- SP Ausnet has a peak in the late 1980s and early 1990s with a significant drop in the late 1970s; and
- Jemena has roughly the same value of assets installed from the late 1960's to the late 1990's.

Figure 3.2
Replacement cost for electricity distribution assets for Ausgrid (FY09 $m real)



Source: EnergyAustralia, *Regulatory Proposal*, June 2008, p.5.

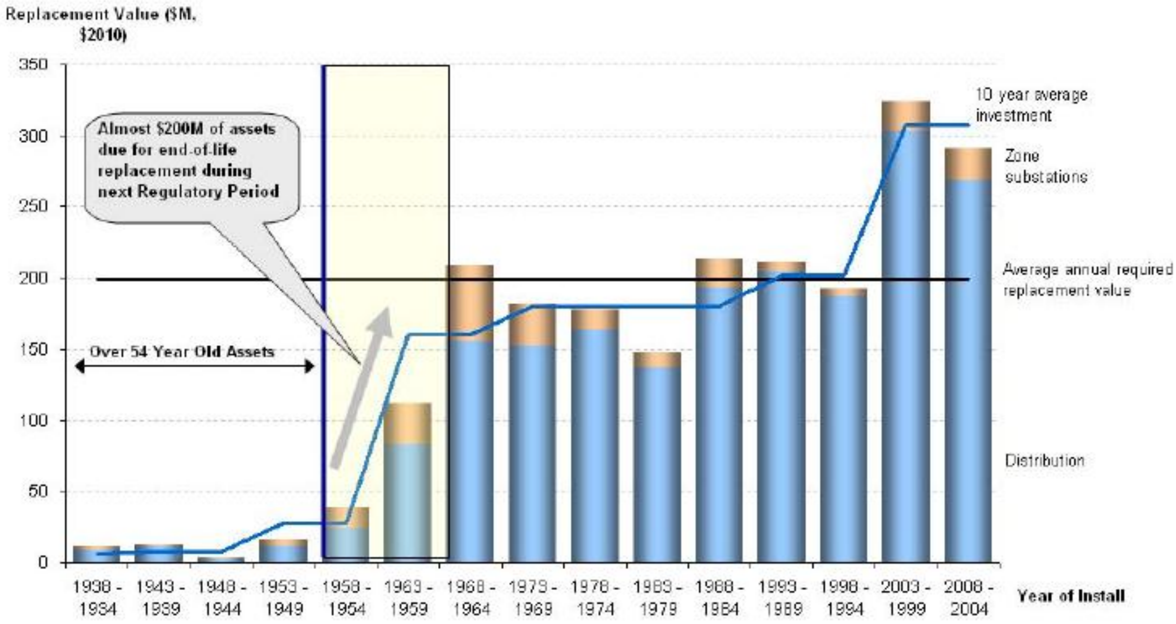
Figure 3.3
Network Age profile, SP AusNet



Source: *SPI Electricity*, *Electricity Distribution Price Review 2011-2015, Regulatory Proposal*, November 2009, p.45.

[51] Mountain (2011), p.74.

Figure 3.4
Asset replacement value by installation year for Jemena



Source: Jemena, *Regulatory Proposal 2011-15*, November 2009, p.95.

Since the age profile of electricity distribution assets vary across DNSPs, the average age of assets is not the appropriate way to calculate the value of assets that need replacing.

In contrast to Mountain's conclusion, the AEMC has identified ageing assets as one of the main drivers of the rising costs of distribution services in NSW.[52] NERA analysis has also shown that replacing ageing assets has been a significant cause of the recent increase in capex for some DNSPs.[53] For example, asset renewal and replacement contributed 56 per cent of the total increase in the real capex allowance for Ausgrid in the current regulatory period.[54]

3.3. Historic underinvestment

In considering the issue of historic underinvestment, Mountain looks at two reports:

- Pierce, J., Price, D., Rose, D., *The Performance of the NSW Electricity Supply Industry*, Reserve Bank of Australia, 1995; and
- Independent Panel, *Detailed Report of the Independent Panel: Electricity Distribution and Service Delivery for the 21st Century*, July 2004.

The first report found that 'between 1982 and 1994 average annual capital productivity growth of New South Wales distributors was just 0.2 per cent per annum, and that New South Wales distributors could achieve 20-30 per cent reduction in operating costs through

52 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*, November 2011, p.21.

53 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

54 NERA, *Analysis of Key Drivers of Network Price Changes*, April 2012.

efficiency gains'.[55] On this basis, Mountain concludes that 'there is no evidence to suggest that the higher expenditure by New South Wales distributors since 2000, and particularly over the current regulatory period is needed to make up for historic underinvestment. In fact the available evidence suggests exactly the opposite is the case.'[56]

The relevance of potential efficiency gains that may have been available up to thirty years ago is highly questionable. That average annual capital productivity growth was low *between 1982 and 1994* tells us nothing about the need for investment *since 2009* to make up for past under-investment. Even if this information were more recent, capital productivity growth and opex inefficiencies would tell us little about the need for catch-up investment.

The second report cited by Mountain claims there had been underinvestment in Queensland's electricity distribution. However, Mountain discounted this report mainly due to questions about the methodological robustness of the measure of overall average capacity utilisation and an argument that the finding that Energex should adopt higher planning standards did not show that Energex had failed to meet the required standards.

Mountain does not provide a compelling case for discounting the argument that a certain amount of current investment is required to make up for past levels of under-investment.

3.4. Higher network planning standards

Queensland and New South Wales have recently set higher standards for DNSPs, which have argued that meeting these standards has required considerable additional capex. Mountain concurs that this is likely to have been the case and that this could explain part of the difference between the expenditures of New South Wales and Queensland with other States.[57]

However, Mountain also notes that this improvement in standards has not had a measureable effect in terms of the quality of the service. We note that improvements in network planning standards may not create substantial and immediate increases in observable measures of quality for a number of reasons:

- it takes some time for investment to be carried out and a new asset to become operational;
- higher standards will only relate to new work and this is a small proportion of a total network;
- there is a substantial amount of volatility in the interruption statistics used by Mountain to measure quality; and
- improvements in quality may well result from higher standards without them being observable in current statistics on interruptions. For example, the higher standards may protect against a disruption in electricity distribution in a major flood. However, if the major flood never occurs, the standards will not lead to any measureable change in the number or length of electricity interruptions..

[55] Mountain (2011), p.39.

[56] Mountain (2011), p.42.

[57] Mountain (2011), p.42.

The AEMC has identified higher reliability standards as one of the 'main drivers of the rising costs of distribution services in NSW'.[58] The AEMC has explained this as follows:

> '[a]dditional capital expenditure over the current regulatory determination is also needed to meet the higher reliability standards for New South Wales distributors. In 2005, the New South Wales Minister for Energy amended the licence conditions of New South Wales distributors to require them to comply with new design, reliability, and performance requirements by 2012/13. This has contributed to further anticipated capital works by the distribution businesses, particularly Essential Energy, to meet these standards within the required timeframes. The AER has advised that reliability and quality of service enhancements comprise around 10 per cent of the total capital expenditure by New South Wales distributors over the current regulatory period.'[59]

In our opinion, higher network standards are likely to have resulted in higher expenditure by some DNSPs. However, the analysis in Mountain (2011) does not allow for an estimate of the scale of this effect.

3.5. Asset valuation

Mountain shows that the values of the regulatory asset base (RAB) per customer are higher in New South Wales and Queensland than in South Australia and Victoria. In addition this difference is increasing over time.

Mountain suggests three possible reasons for this:

- the networks in New South Wales and Queensland are newer;
- there may be different definitions of transmission and distribution in different states; or
- governments are likely to have a greater incentive to increase the RAB as they receive the dividend from the profit.

Mountain notes that government owned distributors value their easements at significantly higher levels than the DNSPs in Victoria and South Australia. He concludes that 'the fact that government owned distributors are valued so much higher per kilometre of line than privately owned distributors suggests that ownership has affected asset valuation.'[60]

As discussed in the sections above, capex has been higher in New South Wales and Queensland than in South Australia and Victoria. Furthermore, there are a number of legitimate reasons for this, none of which have been credibly refuted by Mountain. This will be, at least in part, driving the differences in the RAB, as noted by Mountain.

It is also unclear whether Mountain (2011) has taken into account the recent increase in the value of easements in South Australia from $8m to $123m.[61] This increase means that one of

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58 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2010 to 30 June 2013*, November 2011, p.21.

59 AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011, p.31.

60 Mountain (2011), p.44.

61 Application by ETSA Utilities [2010] ACompT 5 (13 October 2010), available at <http://www.austlii.edu.au/au/cases/cth/ACompT/2010/5.html>.

the states in which distributors are not government owned has very substantial easement values.

Furthermore, Mountain has not considered a range of other factors that will results in higher RABs in Queensland and New South Wales compared to South Australia and Victoria. These factors have been discussed in the sections above and include such factors as the need for these networks to be constructed so as to meet higher levels of peak demand.

For similar reasons and because of the complexities of making international comparisons, we do not consider the comparison with RABs in Great Britain to be helpful. We therefore see no evidence to draw a conclusion that the nature of ownership has been a key determinant in establishing the RAB.

3.6. Allowed rates of return

The AER has set a higher allowed rate of return than the jurisdictional regulators had previously set. Mountain points out that the main reason for this is an increase in the debt risk premium. Mountain also notes that Mountain and Littlechild (2010) found that the cost of capital allowed for DNSPs was significantly higher in Australia than the UK.

There has been a significant increase in the debt risk premium since the global financial crisis and this has been a major contributor to higher prices. However, it would be premature to assume that this was due to a failing in the regulatory regime. This issue is considered in greater detail in two complementary reports.[62]

Specifically, for DNSPs, the benchmark now adopted by AER (BBB+, 10 year) is either the same as or a slightly higher grade of debt than that adopted by the previous jurisdictional regulators at the time of the earlier regulatory decisions. This implies that, absent any change in market conditions, the debt risk premium would have been the same or lower for the DNSPs. For the TNSPs the AER benchmark (again, BBB+, 10 year) has been modestly reduced from that applied in the previous regulatory period (ie, A, 10 year). However the change in the benchmark was determined by the AER as appropriate in the 2009 SORI.[63] In neither case does the change in the debt risk premium reflect a shortcoming with the Rules.

3.7. Customer density

Mountain considers whether customer density may explain the difference in costs between Australian distributors and those in the UK. He concludes that it does not.

However, Mountain's assessment is not compelling for a number of reasons. Most importantly, in comparing customer densities and costs, Mountain does not adjust for other factors. In other words, his assessment is not based on 'all other things being equal'. Mountain provides an example of a DNSP with a lower customer density that has lower costs than two other DNSPs with a higher customer density. However, it still may be the case that lower customer density increases costs because the difference between the DNSPs' costs in the example may be driven by other factors.

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[62] NERA, *Analysis of Key Drivers of Network Price Changes,* April 2012 and NERA/PWC, *Debt Risk Premium – Response to the AEMC Direction Paper,* April 2012.

[63] AER, *Statement of the Revised WACC parameters (transmission)*, May 2009, p.6.

Furthermore, by considering simple correlations between customer density and expenditure levels, Mountain only assesses whether there is a linear relationship between network density and the cost of electricity distribution. It is likely that the relationship will be more complex than this. For example:

- the cost of distribution per customer in a dense urban environment can be very high since the distribution wires may need to be underground and access to buildings may be necessary;
- where density is fairly low, for example just outside a city, customers may be supplied with single wire earth return lines over open ground that travel fairly short distances and the cost of distribution may be less than in an urban environment;
- where customer density is very low indeed, distribution may be by means of a single wire earth return line but the distance between each customer would push up cost of distribution per customer; and furthermore
- two areas with the same customer density but different clustering patterns may have different average costs. For example, a rural area with a small village surrounded by relatively empty countryside may have lower average costs than a rural area with a number of households spread throughout the countryside.

Therefore, customer density may have a complex and non-linear effect on the cost of electricity distribution. The analysis in Mountain (2011) is not able to detect such a relationship. Hence, in our opinion, the analysis presented in Mountain does not provide a compelling argument for discounting customer density as an explanation of cost differences.

3.8. Ownership

After discounting some explanations for recent price increases, Mountain concludes that Government ownership is a key determinant of higher prices, giving the following reasons:

- private firms can be expected to be more interested in maximising profit and therefore will be more responsive to regulatory incentives that reward reducing expenditure;
- a government that is also an investor will be more receptive to regulation that increases dividends than a government that is not an investor; and
- the target rates of return in the public sector are lower than the private sector such that government-owned DNSPs will have an incentive to invest more in capital expenditure than private businesses.

As discussed in the sections above, we do not believe Mountain has provided compelling reasons to discount legitimate explanations for cost differences considered above. Furthermore, Mountain has not undertaken any analysis to determine the extent to which many state-specific factors will have a justifiable impact on cost differences.

Evidence that DNSPs in NSW and Queensland (which are state owned) have higher costs than those in Victoria and South Australia (which are publicly owned) does not prove that ownership is the cause of this difference.

The explanations of the incentives of government-owned businesses are also not compelling, especially given the separation between the states and the regulator. In our opinion, Mountain does not have sufficient evidence to draw the conclusion that differences in ownership are the cause of the variations in expenditure.

3.9. Regulatory design and conduct

After discounting the various other explanations for recent price increases, Mountain concludes that the regulatory framework must also be a key determinant of higher prices. As discussed above, Mountain has not provided compelling arguments for discounting these other explanations of the price increases. Therefore, there is no basis upon which to conclude that regulation must be responsible for the recent price increases. However, we have addressed each of Mountain's concerns, briefly, in the interests of completeness.

Mountain raises three concerns about the existing regulatory framework:

- the 'propose-respond' doctrine puts an onus of proof on the AER to justify any amendments to the DNSPs price forecasts and this puts the regulator at a considerable and unfair disadvantage;[64]
- the asymmetry of the appeal process unduly favours DNSPs and allows 'cherry picking'; and
- the AER has not made as much use of benchmarking as it could.

Mountain's portrayal of the current regulatory framework is somewhat inaccurate. In particular, there is no 'onus of proof' in the current process for setting expenditure allowances. No forecast can ever be 'proved' and this concept simply does not fit with the task to be undertaken. In assessing DNSPs submissions, the regulator must accept a forecast only if ***it is satisfied*** that the forecast reasonably reflects efficient costs, the costs a prudent operator in the circumstances of the NSP would require. This issue is considered in further detail in *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*.[65].

Mountain's interpretation of the approach in Great Britain is also not entirely accurate. Ofgem also gives considerable weight to the submissions of the regulated businesses and is required to provide reasons for its decisions under Section 42 of the *Utilities Act 2000*. Although on the surface the UK regulatory regime may appear to provide Ofgem with considerable discretion that is not available to the AER, in practice the extent to which Ofgem may exercise unguided discretion is heavily constrained by the ability of NSPs to reject price control proposals and initiate a wide ranging merits review process.

Furthermore, we do not consider it the case that DNSPs have 'strong incentives to make ambit claims'.[66] This has been discussed in a recent joint report for the ENA which concluded that the AER has not been constrained to accept inflated total expenditure forecasts proposed by the NSPs.[67] For example, the AER has not accepted NSP's proposed total expenditure forecasts in any of its determinations.

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[64] Mountain (2011), p.51.

[65] NERA/PWC/Gilbert+Tobin, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

[66] Mountain (2011), p.54.

[67] NERA/PWC/Gilbert+Tobin, *Assessment of the AER's Rule Change Proposals for Forecast Expenditure*, December 2011.

In regard to the appeal process and the potential for cherry picking, there is no evidence presented as to how or why this may currently be occurring. It is very costly to take an appeal to court and therefore unlikely a DNSP will appeal unless some part of a decision is substantially detrimental to it. If the regulator knows this and has an incentive to attempt to reduce prices then it may be able to set prices below the median reasonable level. This is in direct contrast to Mountain's contention that the appeal mechanism probably also encourages 'the AER to err on the side of the distributors in their regulatory decisions'.[68]

Mountain's point in relation to benchmarking appears to be a criticism of the AER's implementation of the regulatory framework rather than the framework itself. However, it is noteworthy that the AER undertook a number of benchmarking exercises in its recent determination of the prices for electricity in New South Wales.[69] For example, it undertook a benchmarking exercise for Ausgrid's controllable opex.[70]

[68] Mountain (2011), p.55.

[69] AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, April 2009.

[70] AER, *New South Wales distribution determination 2009–10 to 2013–14*, Final decision, April 2009, p.174.

4. Mountain (2012)

Mountain's second paper for the EUAA, *Electricity Prices in Australia: An International Comparison,* was not submitted to the AEMC as part of the review of the NER. However, the timing of its release makes it likely the paper will receive some attention in the course of this review.

Mountain (2012) provides an international comparison of electricity retail prices. On the basis of this comparison, Mountain concludes that Australian prices are high and rising when compared to those in other countries.

We have three main comments in relation to this report:

- the report is of limited relevance to the purposes at hand, so while it can be considered interesting it is not directly applicable;
- making international comparisons is complex and other commentators have arrived at quite different conclusions regarding Australia's retail electricity prices; and
- international comparisons must be interpreted with care as there will be many factors driving price differences.

4.1. Relevance of Mountain (2012)

Mountain has not claimed this report is relevant to the rule change review and the report has not been submitted as part of this review. The report's limited relevance stems from two factors.

First, this is a comparison of *retail* electricity prices whereas the review is concerned with transmission and distribution costs. Without separating the effects of retail and generation costs it is impossible to make any conclusions regarding the relative cost of network services.

Second, the household sector used around 25 per cent of all electricity consumed in Australia in 2009-10, with the industrial sector making up the other 75 per cent.[71] Hence, the retail prices are a small part of the total price and may bear no relation to the prices for industrial users.[72]

4.2. Complexity of making international comparisons

Comparing international retail electricity prices for households is not a simple exercise for a number of reasons.

71 ABS, *Energy Account*, 2009-10, p.21.

72 We used a report by the Ontario Power Authority to list countries from lowest to highest industrial and residential electricity price. The Spearman rank correlation coefficient of these two lists was 0.75. Given that this is not a perfect correlation; a country which has higher household electricity prices relative to other countries will not necessarily have higher industrial electricity prices. Source: Ontario Power Authority, *Delivered Electricity Price Comparison*, August 2008.

Retail tariffs tend to be structured with fixed and variable components. In some regions, there are multi-part tariffs, such that the price per unit may increase (or decrease) as consumption increases. For a comparison to be meaningful, it should consider households with similar consumption levels. It is not evident that Mountain has compared such similar households. Indeed, a review of the data Mountain has used suggests this is not the case.

The choice of exchange rate will also play a key role in determining price relativities. Mountain presents information on the basis of two exchange rates: market exchange rates; and PPP. As discussed in section **Error! Reference source not found.**, the PPP is generally thought to provide more meaningful comparisons of costs across countries.[73] Mountain's PPP based comparison significantly narrows the gap between retail prices in Australia versus overseas. In fact, on this basis, Mountain finds that Australian prices are actually lower than those in Japan and the EU.

Care must also be taken when considering prices that are for different regulatory periods. We note that data limitations have meant that the prices in Mountain (2011) are for different periods:

- Australian data are for 12 months *beginning* 1 July 2011;
- the European Union prices are for the first 6 months of 2011;
- the Canadian and Japanese prices are for 2010; and
- the prices for the USA are for the 12 months to November 2011.

Mountain justifies his use of these data on the basis that prices in other countries have not been increasing much. However, we do not find this argument compelling. For example, household electricity prices in the following countries have increased by more than 30 per cent in nominal terms in three and a half years to 2011: Czech Republic, Spain, Latvia, Lithuania, Hungary, Malta, Sweden, Norway and Turkey.[74] According to the UK government, the price of electricity in the UK has increased in real terms by around 57 per cent from 2002 to the third quarter of 2011.[75] This is approximately the same growth as in Australia.

Furthermore, comparisons of Australia's AEMC projections for 2013/14 with the historic prices in other regions must be interpreted even more cautiously as it is highly unlikely prices will remain constant in those regions from 2010 to 2014.

Mountain's results are in contrast to others that have found Australia does not have particularly high electricity prices by international standards. For example:

[73] The OECD explains that PPP are used to analyse relative price levels across countries <http://epp.eurostat.ec.europa.eu/portal/page/portal/purchasing_power_parities/introduction>, accessed 25 March 2012. The OECD also describes spatial comparisons of price levels as a recommended use of PPP (OECD, 2008 benchmark PPPs measurement and uses, p.2).

[74] Based on NERA analysis of Eurostat data for electricity prices for households from the second half of 2007 to the first half of 2011.

[75] The index of electricity prices in real terms was 90.4 in 2002 and 141.8 in Q3, 2011. Source: Department of Energy and Climate Change, *Quarterly Energy Prices*, December 2011, p.16.

- in 2010 Australian household electricity prices were the 24th cheapest out of 32 OECD countries, according to a 2012 report by the Bureau of Resources and Energy Economics;[76]
- in 2010 Australian residential electricity prices were the 6th most expensive of 11 developed countries, according to a 2010 report by Deutsche Gesellschaft für Technische Zusammenarbeit;[77] and
- in 2007 Australian electricity prices were the 22nd cheapest for industrial customers and 24th cheapest for household customers out of 27 countries, according to a 2008 report by the Ontario Power Authority.[78]

The differences between the results of the studies demonstrate the complexity of making such international comparisons.

4.3. Interpreting international comparisons

Retail electricity prices depend on many factors and trying to draw broad conclusions from international comparisons is almost impossible. For instance, retail prices will, among other things, depend upon:

- the nature of generation;
- tax and regulatory arrangements – although Mountain has taken the pre-tax retail prices, these will not remove the effect of government policies on prices. In Australia for example, the AER has identified the effect of the renewable energy target, feed-in tariff schemes, the carbon tax and various State based policies on electricity prices.[79] There are numerous other policies that will affect the international comparisons in Mountain (2012) including those on planning, regulation, the environment, tariffs, industry subsidies and health and safety;
- the nature of electricity demand, including the level of peak and average demand, the mix of industrial and household customers, population density; and
- the nature of the electricity network, including its age, geographical coverage, service standards.

Drawing conclusions from international comparisons is even more difficult when the information is presented as averages. While it might be possible to consider reasons for price differences when comparing countries on a one-to-one basis, it is much more difficult to make definitive conclusions when comparing Australian prices with, for example, the average price in the EU.

4.4. Conclusion

Mountain (2012) is of limited relevance to the purposes at hand, so while it can be considered interesting it is not directly applicable. This is because it relates to *retail* prices rather than the

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[76] Bureau of Resources and Energy Economics, *Energy in Australia 2012*, February 2012, p.41.

[77] Gtz, *Overview of electricity tariffs in G 20 and N11 countries*, 2010.

[78] Ontario Power Authority, *Delivered Electricity Price Comparison*, August 2008.

[79] AEMC, *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*, November 2011.

network costs. Furthermore, the study is limited to *household* customers, ignoring the relative prices of industrial customers.

International comparisons are a complex undertaking which necessarily involves considerable discretion, in terms selecting of basket of consumption, the exchange rate and the period of time that the comparison is made. In exercising this discretion, Mountain has emphasised comparisons based on market exchange rates whereas the PPP comparisons are arguably more appropriate. We note that Mountain's own analysis indicates that on a PPP basis Australian retail electricity prices are lower than those in Japan and the average of that in the EU. A further concern we have with the Mountain analysis is his use of older data for jurisdictions other than Australia, that is likely to bias his analysis. We note that other respected commentators have arrived at quite different conclusions regarding Australia's relative retail electricity prices.

It is also important to interpret such international comparisons with care as there will be many legitimate factors driving price differences across jurisdictions.

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Appendix C

Responses to Issues Paper questions

Appendix C. Responses to Issues Paper questions

No.	Question	Comments
1	**Scope of the inquiry**	
1	Given the various ongoing reviews and the consultations associated with them, how can the Commission best add value? Do these reviews have the same broad objective as the Commission or are they more narrowly focussed?	The area where the Productivity Commission can make the greatest contribution is to provide guidance on the practical role that benchmarking can play in improving the efficiency of the electricity network industry. The use of benchmarking broadly defined is already pervasive (and unavoidable) in the way that the AER assesses almost all network expenditure forecasts under the National Electricity Rules (the Rules). The key question is how the AER's use of benchmarking can be enhanced in order to improve the accuracy of those assessments.
2	**The NEM**	
2	Are there any other major regulations or policies that affect the electricity market that need to be considered when undertaking benchmarking or in understanding any of the possible obstacles to investment in interconnectors?	The Productivity Commission has identified most of the relevant areas. In relation to benchmarking, any Government policy/regulation that impact on costs in a region is also relevant. For example, State land use planning arrangements as these can delay or add costs to new electricity network investments. In addition, past Government decisions can affect future expenditure costs. For example, to the extent that, prior to the creation of the NEM, significant latent capacity was built into some networks by the then Government owner of one vertically integrated industry and not another, then this can alter relative expenditure requirements even today. In relation to interconnection, these matters are dealt with in more detail in the Grid Australia submission. By and large the ENA is not aware of any economically efficient interconnection development that is not occurring that should be occurring .
3	**What is benchmarking?**	
	Partial indicators	
3	What are the best (and worst) aggregate measures of performance and why is this so? In which contexts (Australia and elsewhere) have these most credibly been used?	For the reasons described in section 4.3 of this submission, aggregate measures of performance are likely to be poorly suited to statistical benchmarking. This is because the large number of important independent variables, and the difficulty in accurately measuring those variables, mean that statistical estimates of efficient costs at an aggregate level are unlikely to be robust. The AEMC has concluded that the data required to support the application of Total Factor Productivity (TFP) benchmarking to electricity networks is inadequate and that TFP benchmarking is generally unsuitable for application to electricity transmission (see http://www.aemc.gov.au/market-reviews/completed/review-into-the-use-of-total-factor-productivity-for-the-determination-of-prices-and-revenues.html) .

4	What partial indicators are meaningful? Are there particular parts of network businesses that are easier to benchmark? What are these, why is it easier and what have benchmarking studies revealed?	Section 4 of the submission deals with this question. In summary, statistical benchmarking is most robustly performed where: • the expenditure being benchmarked captures activities that are substitutable in the achievement of a particular outcome (e.g. maintenance and replacement expenditure on a particular asset class); • there are only a small number of cost drivers; • these cost drivers are capable of being quantified (e.g. there may be difficulty in meaningfully quantifying such factors as 'amount of vegetation', 'network design approaches' that reflect historical decisions and factors (e.g., see http://electrical-engineering-portal.com/basics-of-subtransmission-systems), 'urban density', 'topography' etc; • the cost drivers have a stable (ideally linear) relationship to costs allowing less probability of model specification error; and • the results of the statistical benchmarking can be subjected to a 'sanity check' and/or reasonably contested by the business in question. For the reasons described in this submission (see section 4.3.1.4), the ENA believes that these conditions are most likely to be satisfied when benchmarking is performed at a disaggregated level.
5	Are there criteria beyond those identified in Box 1 that are useful for discriminating between good and bad benchmarking tools and approaches?	The criteria listed in Box 1 are comprehensive but lack an overriding principle for assessing when they have been met (see discussion in section 6 of the submission). The Rules have such criteria, which the ENA believes are appropriate. In addition the National Electricity Law requires that, businesses must have a reasonable opportunity to recover at least the efficient costs of providing network services and meeting relevant regulatory obligations (as set out in the Revenue and Pricing Principles in section 7A of the National Electricity Law).
6	What are the weaknesses and advantages of full versus partial measures for benchmarking?	This question is addressed in section 4 of the submission. In summary, the answer reflects the extent to which aggregate or disaggregated benchmarking is able to satisfy the criteria set out in response to question 5 above. The ENA's view is that statistical benchmarking is most likely to be robust when performed at a disaggregated level (see specifically section 4.3.1.4 of this submission).
7	What methods should be used for benchmarking (indexes, corrected ordinary least squares, data envelopment analysis, simple ratios) and what are their strengths and weaknesses?	It is not the ENA's intention to be prescriptive. Rather, the key point is that the benchmarking methods that will be appropriate (in the sense of being robust and consistent with the incentive-based regulatory framework in the Rules) will depend on the available data and the activity being analysed. The criteria in section 6 and the case studies in section 7 of the submission provide a useful starting point for thinking about which benchmarking approaches will be appropriate.
	Using benchmarks to assess regulatory performance	

8	Could benchmarking be used to assess the effectiveness and efficiency of different regulatory settings (such as reliability standards)?	Numerous enquiries into distribution planning standards have, correctly, had regard to 'good practice' in other jurisdictions including internationally, as well as expert assessments. This has proved useful as a check on the standards derived through other approaches e.g. economic assessment. The AEMC is currently reviewing the distribution reliability standards framework set out in the Rules (see http://www.aemc.gov.au/Market-Reviews/Open/review-of-distribution-reliability-outcomes-and-standards.html).
9	Are there examples where regulatory benchmarking has been used in electricity networks in Australia or overseas?	Regulatory benchmarking has been used consistently by the AER in the electricity and gas context (examples are discussed in the submission). Other examples include telecommunications and water regulation (by the ACCC and State regulators). Benchmarking is also a feature of a number of overseas regimes including the OfGem RIIO regulatory framework.
10	Are there any other broad benchmarking approaches not discussed above and where and how have these been used?	In the ENA's view, almost all components of the AER's assessment of expenditure forecasts are based on benchmarking in some form. In particular, expert review is a form of benchmarking (see section 4.1.1. of the submission) and the use of incentive regulation involves benchmarking against past performance (as discussed in section 4.2 of the submission).
4	**But is benchmarking practical?**	
	Is imperfect benchmarking still useful?	
11	Is there a big enough problem to justify new approaches to benchmarking and to incorporate it into regulatory incentive arrangements? To what degree could perceptions of inefficiency reflect the newness of the current regulatory regime or a failure to sufficiently adjust for the differing starting points of different distribution businesses?	The current regulatory arrangements provide ample opportunity for the application of various benchmarking approaches. Again, the key issue is to ensure that the approaches used are appropriate in terms of their need to be both robust and consistent with the wider incentive-based regulatory framework. The electricity price increases experienced in recent years naturally invite questions about the efficiency of the network businesses. The ENA considers that: • the network component of those price rises has been efficient; • while there are some areas where the Rules could be improved, they do not prevent the AER from using benchmarking as part of setting network revenues at efficient levels; and • the way in which the AER applies the Rules in some areas (eg cost of debt) has contributed to the perception that network charges are inefficient and that changes to the Rules are therefore required. These matters are currently being reviewed by the AEMC. Its Directions Paper on the Rule change proposed by the AER and Energy Users Rule Change Committee (EURCC) is matter is instructive in relation to the above (see http://www.aemc.gov.au/Electricity/Rule-changes/Open/economic-regulation-of-network-service-providers-.html).

12	How do existing network suppliers assess the efficiency and performance of their own businesses and how do they use these results? Could these results have relevance to regulatory benchmarking and, if not, why not?	An important element of the regulatory framework under the Rules is that there is a “revealed costs” incentive for businesses to develop and apply partial benchmarking to improve their own efficiency. However, as is the case with all benchmarking, partial measures are best interpreted in the context of the wider set of available information. This information also assists businesses in demonstrating to the AER that its applications for five year revenue paths are reasonable.

13	How should benchmarking be used by the regulator? For example, to what degree could and should it be used a ‘high powered’ incentive regulation: as a basis for determining the weighted average cost of capital and efficient spending or as public information to provide moral suasion for efficiency?	The way in which benchmarking should be used is discussed in Section 4 of the submission. In summary, the AER can, and does, use benchmarking as an important basis for assessing businesses expenditure forecasts. This often takes the form of benchmarking within the context of an expert review having regard to all the available information whereas the role for purely statistical benchmarking depends on how robust the results are as a means of estimating the efficient level of costs in the circumstances facing the business. Where the estimates from statistical benchmarking are robust and predictable then they could be used to set expenditure allowances and, thereby, provide high powered incentives. Where they are less robust they are better suited to providing a ‘first step’ or an adjunct to benchmarking via a more detailed expert review of costs. Whether benchmarking is robust or not will depend on the amount of work that has gone into properly preparing for the analysis, including collecting the available information. It will also depend on the inherent attributes of the activity being benchmarked. In particular, aggregate levels of expenditure are unlikely to be able to be robustly statistically benchmarked due to the large number of independent variables that need to be accounted for and the small number of observations of dependent variables available for statistical analysis. The requirement for robust benchmarking should be maintained. Otherwise, there is a risk that the AER will use non-robust benchmarking to manage price shocks and, in so doing, severely damage the holistic incentive regulatory framework that the Rules establish (see also discussion by Yarrow as referenced in section 3.3.2 of this submission). With respect to the use of statistical benchmarking of aggregate expenditures as a means of applying ‘moral suasion’ it must be recognised that there will inevitably be type I (incorrectly identifying a firm as inefficient) and type II (incorrectly identifying a firm as efficient) errors. If the estimates of efficient expenditure are not robust then they will be of limited value in terms of moral suasion and may be counterproductive. That is: • a business that needs to increase spending may feel under pressure not to in the presence of a type I error; and • a business that should be spending less may feel no pressure to do so in the presence of a type II error. In particular, if aggregate statistical benchmarking was given undue credence in a ‘moral suasion’ sense, the existence of type II errors would make it hard for the AER to reject expenditure proposals from firms identified as efficient. This in turn would give those firms an incentive to exaggerate their expenditure forecasts. Most importantly the misapplication of benchmarking can lead to the inappropriate ‘write down’ of sunk costs ie expropriate property rights, seriously impacting on the provision of investment capital to the development of essential network infrastructure. In relation to the cost of capital assessments, a key revenue building block, the AER is expressly required to determine this with reference to a benchmark firm.

14	What is the magnitude of the benefits from using benchmarking in regulatory decision-making in terms of lower unit costs or other performance measures?	The magnitude depends on the circumstances of the business, its performance relative to either or both of its past outcomes and comparator businesses and the costs of conducting benchmarking relative to other measures of performance. Irrespective of the size of the benefits, again what matters is the robustness of the process used to determine them and pure statistical benchmarking alone is unlikely to be robust enough unless used in conjunction with expert engineering assessments.
15	What are the lessons from overseas about their benchmarking approaches and what aspects should Australia copy or avoid?	Again, this comes back to the robustness of the benchmarking. At this point in time, the ENA does not consider that there is sufficient data or experience in conducting robust benchmarking to support relying on pure statistical approaches to determine network revenues or prices. The regulatory risk is simply too great.
16	To what degree could the AER use international benchmarking?	International benchmarking could be used by the AER under the current Rules provided it was robust. The use of international data in purely statistical benchmarking can, in theory, improve the accuracy of the analysis by increasing the number of observations of the dependent variable (i.e. expenditure). However, it also tends to increase the number of independent variables that need to be accounted for (e.g. exchange rates, different network designs, etc). Consequently, whether the use of international data is useful will depend on the circumstances. This is discussed in section 4.3.1.2 of this submission.
17	How can a good benchmarking model be identified since data and methods always have some imperfections?	Statistical measures of the accuracy of predictions exist and can be used to assess robustness. However, good benchmarking needs to be able to explain a great deal of the variation in the sample. Bad benchmarking observes errors terms in the model and automatically ascribes these to inefficiency/efficiency rather than attempting to discover cost drivers not accounted for in the study or specification error in the model. Moreover, the outcomes of the model must be, and must be able to be, tested against other information. Specifically, if a business is found to be inefficient through the application of a statistical model, the opportunity must exist for the business to demonstrate that this could involve a Type I error (i.e. to show that the inefficiency could be attributable to a factor which has been poorly accounted for by the model). This is a further reason for preferring statistical benchmarking to take place at a disaggregated expenditure level because 'sanity checking' of model results at this level is easier than if many different types of expenditure with different cost drivers are lumped together (see section 4.3 of this submission) Similarly, any such finding should be tested by the regulator for consistency with information that was not/could not be included in the model. For example, no single metric for 'topography' may be able to be quantified for use in a statistical model. However, the regulator should still examine the results of the study to test whether differences in topography may give rise to an omitted variable problem.

18	Is there value in 'rough and ready' benchmarking models and how would these be used?	There can be value to such models provided that the limitations are understood and that the results are used as a 'first step' rather than a 'last step' in any investigation of expenditure forecasts (see section 4.1 of the submission).
19	What are the most important control factors for benchmarking network businesses (for example, lot frontage, asset vintage, topography, weather variations, customers types, reliability standards, ratio of peak to average demand and any strategic behaviour by generators and retailers)? What matters less?	The factors that need to be accounted for depend on the individual circumstances of the businesses. Examples of these factors are set out in section 5 of the submission.
20	What are the main differences in the potential for, and methods of, benchmarking transmission versus distribution businesses?	The potential for aggregate benchmarking of transmission is less than for distribution, as set out in the AEMC's total factor productivity (TFP) review (see http://www.aemc.gov.au/Market-Reviews/Completed/review-into-the-use-of-total-factor-productivity-for-the-determination-of-prices-and-revenues.html). Output related performance measures in transmission are more problematic because of the importance (and economic benefits) of keeping major interruption events down to a very low number.
21	Should benchmarking results and methodology be publicly available and, if not, why not?	The only limitation on the publication of benchmarking studies should be the withholding of legitimately confidential information. Examples include tender prices for equipment purchases or construction contracts where public disclosure would undermine the competitive tendering process. Subject to this, it should be incumbent on the regulator and its consultants to publish methodologies, analysis, assumptions and calculations to facilitate stakeholder review. Recent benchmarking comparisons by Mountain on the relative cost of electricity in Australia compared with overseas falls provides a good example of the consequences where this level of disclosure is not undertaken (see further Section 7.6 of the submission)

22	What are the consequences of errors in benchmarking? To what extent do these costs vary for positive versus negative errors? How could the costs of any error be reduced?	The major risk in relying on non robust purely statistical benchmarking to determine revenue outcomes for regulated networks is to fail to provide these businesses with a reasonable opportunity to recover the efficient costs of meeting a regulatory obligation. This is one of the pricing principles set in the National Electricity Law aimed at providing reasonable certainty for investors in long lived electricity transport assets. As noted by the Productivity Commission in previous reviews, the consequences of underinvestment can be much more serious than overinvestment, particularly when it is recognised that significant amounts of future investment in network businesses is required in coming decades. This problem is exacerbated if non-robust benchmarking is used by the regulator as a tool to manage price shocks for end customers. As noted by Yarrow and as discussed in section 3.3.2 of this submission there can be substantial pressure on regulators to force businesses to absorb cost increases – even when those cost increases are efficient and in the interest of end customers. If non-robust benchmarking is able to be relied upon by the regulator, then this creates a bias towards type I errors in periods of rising costs (i.e. incorrectly finding businesses to be inefficient). It must also be noted that the Rules require the AER to assess businesses expenditure proposals. If pure statistical benchmarking is used to do this then a business that knows it will be identified as 'efficient' by statistical benchmarking has an incentive to increase their expenditure forecasts (at least up to the point at which they still expect to be found to be 'efficient' by the statistical model).
23	To what extent would it be helpful to give the AER some discretion in deciding how much weight should be given to benchmarking and other tools when making regulatory determinations?	The AER already has discretion in deciding what weight to give to statistical and other forms of benchmarking. As noted by the AEMC, provided that the selection of benchmarking methodology and its execution were robust and otherwise consistent with the Rules and Law (including the revenue and pricing principles set out therein), there is nothing to prevent the AER from using a specific methodology. In the TFP example referred to in the answer to question 20, the AEMC noted that suitable data for its use did not exist at the time of the review. The most useful outcome of the Productivity Commission's review would be to provide guidance on which different types of benchmarking are likely to be robust and consistent with the incentive-based framework contained in the Rules.
24	What, if any, alternative policies may be superior to benchmarking? What, if any, policies could complement the use of benchmarking?	The current Rules are designed to address information asymmetry issues and to provide incentives for businesses to improve efficiency over time and reveal efficient costs. They are also designed to provide an appropriate response to changing forecasts and patterns of demand. Within this incentive-based framework, soundly based statistical benchmarking, along with benchmarking within expert review, and benchmarking against past performance can be used to deliver sound revenue and price cap decisions.
	The importance of testing rival explanations	

25	What are the principal reasons for the apparent decline in the productivity of the electricity networks and for the associated increases in electricity prices? In particular, what have been the effects of rising input prices, past underinvestment, building ahead of use, rising peak demand, underground cabling and requirements for reliability requirements? To what extent have investment responses to the above factors been economically efficient?	Claims that recent price rises are the result of a decline in productivity should be carefully examined. The ENA's view is that those rises are, broadly, the result of legitimate cost increases, not a problem with the Rules framework. The drivers for those increases vary from business to business as set out in the ENA's submission in response to the AEMC's Directions Paper on revenue setting Rules and, specifically, a paper by NERA included in that submission (a copy of the NERA paper appears at Appendix A to the submission). In overview, key factors include increases in the cost of capital associated with funding scarcity following the Global Financial Crisis, increases in replacement investment as an increasing proportion of the existing asset stock reaches the end of its economic life, changes in planning standards, deteriorating load factor due to increases in peak demand greater than increases in energy usage. The AER decisions relating to these increased allowances have, almost without exception, found these increases to be justified. Further, in its 2010 State of the Energy Market report[1], the AER stated that key drivers for the rising electricity network business revenues include: 'more rigorous licensing conditions and other obligations for network security, safety and reliability; load growth and rising peak demand; new connections; and the need to replace ageing assets, given much of the networks were developed between the 1950s and 1970s.' The Issues Paper stated that the Commission found 'significant reductions in measured multifactor productivity in the electricity sector as a whole over the past decade' (Topp and Kulys (2012)). In understanding this trend, the ENA notes that the below reasons identified by Topp and Kulys in the Staff Working Paper *Productivity in Electricity, Gas and Water: Measurement and Interpretation* align with the drivers identified in the NERA analysis in Appendix A: • "Around half of the MFP decline in ES was due to an increase in the ratio of peak to average electricity demand, which lowered average rates of capacity utilisation. This was largely attributable to rapid growth in household use of airconditioners"; and • "Three other contributors were: cyclical investment in lumpy capital assets, which temporarily increased inputs ahead of growth in output; a shift to greater undergrounding of electricity cabling, which raised costs and the quality of output, but not the volume of measured output; and policy induced shifts away from coal-fired power to higher-cost, but less polluting, sources of new supply".

[1] AER 2010, *State of the energy Market 2010*, p.54

26	To what extent have rising network costs reflected failures to correctly identify project scope, to adequately control project costs and 'gold plating'?	As per the evidence set out in the ENA's submissions in response the AEMC's Directions Paper (including the NERA report included as Appendix A to this submission), the AER has concluded in its reviews of forecast requirements, almost without exception, that the allowances included in its decisions are justified.
27	If there has been gold plating by network businesses, how has this been realised (premature investment, over-specification of network elements, excessive reduction in service interruption risks)?	See the response to Question 26.
28	What is the evidence about the comparative roles of the above factors?	See the response to Question 26.

29	To what extent have Garnaut, Mountain and Littlechild identified genuine inefficiency in electricity networks?	In short, they have not. As set out in the body of, and Appendix B to, the submission, these are examples of poorly applied aggregate benchmarking assessments. For example, Bruce Mountain's 2011 paper *Australia's Rising Electricity Prices and Declining Productivity: the Contribution of its Electricity Distributors* and *Electricity Prices in Australia: an International Comparison* conclude *inter alia* that regulatory failure and Government ownership are the major causes of recent price increases, rather than the need for investment to replace aging assets and meet the requirements of rising peak demand. Mountain's unsubstantiated conclusions about relative efficiency of DNSPs arise from: • his failure to consider the many legitimate reasons for variances in costs per connection (service quality standards, past expenditure decisions and the nature of the network, such as the mix between industrial and residential connections, network length, customer density, peak and average demand levels, the split between transmission and distribution networks, etc); • a highly questionable reliance on inappropriate comparisons; and • an incorrect focus on ownership as the key distinction between DNSPs leading to omission of state-specific cost drivers, and failure to review data on a DNSP-specific basis (instead using state averages), masking variations between firms within a state. Mountain dismisses the network businesses' actual investment drivers, incorrectly: • assessing the driver to build to accommodate growing peak electricity demand by considering growth in aggregate demand instead, and considering historic data rather than forward-looking data, whereas of course NSPs must invest to meet anticipated demand growth, not past demand growth. Analysis provided in the [source – and consider whether we include the chart] demonstrates that New South Wales and Queensland are indeed expected to have stronger growth in peak demand until 2020, compared with Victoria and South Australia; • assessing investment being driven by the need to replace aging assets by claiming that government owned NSPs have been given regulatory allowances for replacing aging assets more than that of private NSPs. In drawing this conclusion, Mountain acknowledges that the profile of asset age is more important than the average remaining life but assumes that NSPs have similar asset age profiles making it possible to then simply compare the average. This is simply incorrect; • claiming that there is an element of "catch-up" in investment due to past levels of under-investment, with reference to a single study carried out in the 1990s, which concluded that between 1982 and 1994 NSW distributors were inefficient and capital productivity was poor.
5	**The interaction of benchmarking with the regulatory framework**	
	The process for approving future investment and operating expenses	

30	Do the current Rules limit the use of benchmarking? If so, how do they do so, to what extent and what would be the appropriate remedy?	While there are some areas where the Rules could be improved, as set out in recent ENA submissions to the AEMC, they do not prevent the AER from using benchmarking as part of setting network revenues at efficient levels. These matters are currently being reviewed by the AEMC. Its Directions Paper on the Rule change proposed by the AER and Energy Users Rule Change Committee (EURCC) is matter is instructive in relation to the above (see http://www.aemc.gov.au/Electricity/Rule-changes/Open/economic-regulation-of-network-service-providers-.html).
31	In particular, do the Rules restrict the weight that the AER can apply to benchmarking analysis compared with the information that distribution businesses make available in the building blocks proposals? For example, could the AER reject the evidence from the building blocks analysis if it found compelling alternative evidence of lower required spending from benchmarking?	The Rules encourage network businesses to provide reasonable evidence based proposals. In the event that the AER concludes that the proposals are not reasonable, the AER is able to substitute its own forecasts. The weight that is applied to benchmarking in each step in the process is largely a function of the quality of benchmarking undertaken. Businesses have an incentive to use benchmarking to show that its proposals are reasonable and are not restricted in this regard. The AER does not appear to be restricted in the weight to which it gives benchmarking other than it is required to have regard for other factors such as past actual business costs, forecast service needs etc. The AER is not 'at large' to use poorly constructed benchmarking to arrive at decisions, nor should it be.
32	Must the AER forensically examine each aspect of the building blocks approach even if it believes that a more simple and robust benchmarking approach was available?	The AER has considerable flexibility in the evidence it can bring to bear at each stage of its decision making process. It has not raised any concerns in its decisions or in its Rule change proposal to the AEMC that is prevented by the Rules from testing the reasonableness of a revenue cap proposal by using benchmarking. Indeed there are numerous examples of the use of benchmarking by the AER in its decision processes. In relation to the cost of capital assessments, a key building block, the AER is expressly required to determine this with reference to a benchmark firm.
33	Are there any other limitations faced by the AER in using benchmarking such as the merit review process?	The merits review process imposes accountability on the AER to undertake robust assessments, as it should.
34	What restrictions, if any, should apply to the AER's use of benchmarking or other analytical tools?	As per the main submission, the approaches used must be consistent with the Rules and be suitably robust.

35	Should the AER select the best performer as the benchmark or choose a benchmark close to, but not at, the frontier? What criteria could be used to determine the threshold between unreasonable and reasonable costs?	While the determination of reasonable costs is a matter currently before the AEMC in its assessment of the AER and EURCC Rule change proposals, the following observations are relevant. In a perfectly competitive market prices are set by the highest cost firm who's output is necessary to meet market demand. Firms with lower costs than this earn economic rents. The existence of the potential for these rents is what drives firms to invest in innovations to lower costs. If all networks were compensated based on the lowest cost firm in the industry then this would involve applying a discipline that is more extreme than even that which exists in (the theoretical concept of) a perfectly competitive market. Even if the statistical model used to determine the most efficient firm was perfectly accurate, regulating this way will fail to provide all but the lowest cost business with a reasonable opportunity to recover at least the efficient costs in accordance with section 7A(2) of the NEL. Knowing this, investors would rightly require a higher headline return on investments as compensation for this (and the cost of lending to regulated businesses would rise). Unless this was accommodated for in the regime by a higher regulatory cost of capital, this would lead to under investment. Moreover, in reality the statistical benchmark model will not be perfectly accurate. A major, if not *the* major, explanation for the difference in costs between the average firm and the 'most efficient' firm will be modelling error (either in the specification of the model/cost drivers or in the measurement of the cost drivers). That is, the most efficient firm will appear more efficient than it is simply because some factors may not captured in the model that allows it to achieve lower costs (or there is some factor that is incorrectly captured in the model that predicts that this firm should have higher costs). This doesn't mean that statistical benchmarking based on the "most efficient" comparator can't be used. Rather, it means that judgement cognisant of the above matters should be applied where this is the case. That judgement may involve weighting the results with benchmarking based on average performance to address those risks.
36	In cases where the AER's benchmarking findings cast doubt on building block proposals but do not provide an exact alternative, should there be scope for the AER to negotiate a settlement with network businesses? How would that be achieved?	The current processes address this. Where soundly based benchmarking, including expert review, provides evidence that a proposal from a network business is unreasonable the AER can and does substitute its own forecasts. These decisions can be tested for veracity by seeking a review by the Australian Competition Tribunal.

37	Could benchmarking reduce prescriptive regulation in the Rules? How? Which ones?	The Rules are not prescriptive in the sense that they do not limit the AER's ability to have regard to any relevant information and methodology for assessing the reasonableness of expenditure forecasts. The discussion in the Issues Paper preceding this question relates to aggregate benchmarking undertaken by Mountain (2011) and Mountain and Littlechild (2010) which suggested that the efficient level of expenditure by NSW businesses was significantly below the levels proposed by the businesses (p. 22). The Issues Paper notes that the AER made only small adjustments to these forecasts and raised two possibilities why this was so: • the benchmarking analysis was flawed and only a small adjustment was truly required; or • the businesses' expenditure forecasts were inefficiently high but the AER was prevented by the Rules from materially departing from them. The ENA considers the work by Mountain/Littlechild to be deeply flawed (see section 7 of the submission). However, the more important point is that there may be a third alternative given insufficient credence in the Issues Paper, namely that, if the NSW businesses' expenditure forecasts were inefficient, the AER had the power and ability to substitute a materially lower forecast but, for whatever reason, did not do so. The ENA strongly believes that if the NSW businesses expenditure programs were as grossly inefficient as suggested by Mountain and Littlechild, there would have been ample evidence, including of the type prepared by them and the type uncovered in expert review, that the AER could have relied on in substituting is own forecasts. If one accepts the veracity (or even the ballpark accuracy) of the Mountain/Littlechild conclusions, then the correct view is not that there is a flaw in the Rules, but that there is flaw in how the AER has operated under the Rules. The AER does not need to be given more discretion than it already has. It simply needs to appropriately use the discretion that it already has under the current Rules.

38	How would a regulator use benchmarking analysis that produced cost estimate significantly different from those from the building blocks approach? What approaches have other countries used in such instances?	The premise of this question appears to be that benchmarking estimates sit outside the building block approach. This is incorrect - statistical and other forms of benchmarking can be and are used to set expenditure forecasts. That is, benchmarking, including statistical benchmarking, is used as a means of determining building block expenditure. This is illustrated in the case studies to this submission provided in section 7. To the extent that a particular piece of statistical benchmarking produced estimates of costs that were significantly different to the expenditures proposed by the business, the AER should do what it is required to do now. Specifically: • assess the robustness and reliability of its benchmarking; • test the consistency of its benchmarking estimate against information from other sources (including statistical benchmarking included in support of the businesses proposals, expert assessment of the businesses expenditure program and benchmarking against the businesses past performance); • on the basis of this information, set out its reasoning for accepting or rejecting business's expenditure proposal (either in part or in whole depending on the nature of the evidence and reasoning employed by the AER); and • In the event that the AER rejects the forecast, use the same or additional information to determine an alternative expenditure forecast.
39	Has the AER used benchmarking effectively? Should it adopt different practices? Are there any major process or resource obstacles to the AER's use of benchmarking?	The AER and its experts have used benchmarking both effectively and inappropriately. Examples of these are provided in the case studies in section 7 of the submission. The major obstacle to all statistical benchmarking, and other forms of benchmarking, is the quality of the data available for use in the study. The AEMC has identified data collection as a matter that needs to be addressed, however, some important information may never be able to be easily incorporated into statistical benchmarking (e.g. aspects of past network design decisions that affect future expenditure requirements). In terms of resourcing, the AER has a substantial and vital task in regulating energy network businesses. Whether the regulator has sufficient numbers of suitably skilled resources to carry out its functions properly is a legitimate line of enquiry.
40	Is there scope to introduce competition in parts of the electricity network? If so, where and when? Would that reduce any need for benchmarking in those parts? To what extent could performance in competitive segments be used as benchmarks for non-competitive segments?	The Rules provide mechanisms for identifying and applying different (lighter-handed forms of, or no) regulation to network services that are not monopolistic in nature. There is no in principle reason why performance in competitive segments could not be used to benchmark performance in monopolistic segments. However, the comparisons would need to be robust as the term is used in the submission.

	A potential excess cost of capital for regulated cost recovery	
41	To what extent, if any, are there flaws in the AER's current benchmarking of the WACC and, if so, how could it be improved?	This matter is currently the subject of the AER and EURCC Rule change proposals currently before the AEMC. As part of that process, the ENA has provided expert evidence (NERA report) that the current cost of capital benchmark does not result in excess levels of regulated returns. The AEMC has formed an initial view in its Directions Paper that this is also the case. The ENA and the AEMC are attracted to possible changes in the cost of capital benchmark to better manage differences between current debt costs and average funding costs associated with a debt portfolio. However, there are a number of issues the AEMC must work through before it can conclude that the net results would be an improved approach. There is also an issue with the way in which the AER is applying the current benchmark in calculating the regulated cost of debt. The Australian Competition Tribunal has found the AER has applied a flawed approach on ten different occasions. This could be addressed if the AER was to adopt recommendations by the Tribunal to develop its methodology in consultation with stakeholders in order to produce a consistent and accurate guideline.
42	Is there evidence that the regulatory WACC should be different for government-owned compared with private network businesses? What implications would differential WACC's have for the eventual privatisation of such businesses?	This matter is being dealt with by the AEMC in its assessment of the ENA and EURCC Rule change proposals. The ENA agrees with the AEMC's interim position that there is no basis for adopting a different benchmark WACC based on the ownership of the relevant business.
43	What, if any, are the effects of the various WACC determinations on: the incentives of private versus government-owned network businesses and choices about spending on capital expenditure versus operating expenditures?	This matter is being dealt with by the AEMC in its assessment of the ENA and EURCC Rule change proposals. The ENA agrees with the AEMC's interim position that the WACC framework is not 'over rewarding' network businesses, noting that there will be differences from time to time between the average cost of a debt portfolio and the prevailing costs of debt at the time of a regulatory determination. The evidence on the differences between the behaviour of Government vs privately owned businesses does not support taking different approaches to government versus privately owned businesses. In theory Government businesses are run as 'for profit' corporations where commercial returns to their owners are a significant driver of behaviour. While it is true that these businesses have other objectives such as public safety and environmental responsibility, these are also requirements imposed on and/or adopted by private businesses. Finally, there are differences between privately owned businesses in terms of ownership structure that can result in different behaviours and drivers (eg private equity vs listed companies). The same is also true of Government owned enterprises.

44	How can different patterns between forecast and realised spending between private and government-owned network businesses be explained?	Analysis undertaken by NERA on behalf of the ENA (see Appendix A) shows that there are numerous causes for these outcomes and they depend on the specific circumstances faced by each business. While this can include ownership there are many other factors such as a (relative) need to 'catch up' on previously deferred replacement programs or to address declining load factors (such as that associated with air conditioner penetration).
45	How does the efficiency of private distribution businesses compare with government-owned ones and, if different, why and how would this be remedied?	The evidence of this to date is inconclusive and the conclusion by Mountain provides an example of poor aggregate benchmarking. The flaws in this report are set out in detail in the submission, Appendix B and in response to previous questions above.
46	Do government-owned network businesses have any non-commercial objectives? How do these vary by business type or jurisdiction? How do they affect the behaviour or efficiency of the businesses? Should they be removed or altered? Should they be factored into benchmarking analysis?	All businesses have non-commercial objectives to a greater or lesser degree. These include mandated obligations in relation to public safety and the environment. While there is a trend to national consistency in some areas such Workers Health and Safety, in other areas, such as land use planning requirements, distinct differences remain across jurisdictions. These differences are good examples of the exogenous factors that need to be explicitly addressed if benchmarking is to be robust.
47	While government-owned businesses pay corporate taxes to state governments – consistent with competitive neutrality principles – are those principles undermined by the shareholder status of governments or any other governance issues? Does that affect investment decision-making by government-owned businesses or the determination of reliability standards and other policies by governments?	Specific evidence in support of these propositions is either lacking or demonstrably flawed. The relationship between drivers and allowed revenues for both private and Government owned network businesses is set out in Appendix A to the submission.

48	If any biases towards excessive investment posed by the WACC and the rollover arrangements of the regulated asset base were removed, would that eliminate the need for any further development of benchmarking?	The development of improved benchmarking data and practices is valuable in its own right. This is true irrespective of the accuracy of the WACC estimate and the incentives that exist around capital expenditure. The AEMC is currently considering both matters as part of its review of Rule changes proposed by the AER and EURCC. The AEMC's preliminary position is that the businesses are not being overcompensated for the cost of capital. However, issues have been raised with the design of capital expenditure incentive arrangements. The Rule change process is the appropriate process for addressing these concerns, noting that the design of capital expenditure incentive arrangements has proved challenging for regulators both in Australia and overseas.
	Reliability standards and planning	
49	To what degree do different jurisdictions' reliability standards affect costs, if at all? Do different standards affect the potential and/or incentives for a single network business to extend across its network borders?	Different standards are almost certain to have different cost impacts. By way of example, the NSW Government Parry- Duffy Report (December 2010, page 32) reported "additional pass-through of costs related to capital expenditure of about $1.5b" as a result of recent increases reliability standards in NSW. The AEMC is currently reviewing the distribution reliability standards across the NEM.
50	Why have reliability standards increased over time and what impacts have these increases had on costs?	Reliability standards have been adjusted over time following a series of reviews. The reviews have been precipitated by community concerns that network reliability should be enhanced in order to reduce the time and costs of outages.
51	To what extent would adoption of a probabilistic versus deterministic framework change costs? What risks and benefits would this entail?	The adoption of a probabilistic versus deterministic framework for transmission networks has previously been considered by the AEMC and recommendations provided to the Standing Committee of Energy and Resources. This included a recommendation that, where probabilistic standards are adopted they need to be expressed in deterministic form. Where deterministic standards are utilised these ought to be economically derived. A review of distribution reliability standards in Queensland in the early 2000s recommended a move from probabilistic to deterministic standards.
52	What evidence is there of customer involvement (such as willingness to pay) in setting reliability standards?	Reliability standards for the networks are usually set jurisdictionally. There has been customer involvement in a number of those processes. It should be noted that there are considerable challenges in developing a single, or even multiple, credible measures of the value(s) customers or customer groups place on reliability due to the wide range of customer circumstances and preferences.
53	How are existing reliability incentive schemes functioning and how could benchmarking contribute to their design?	Reliability incentive schemes have only recently been implemented and it is too early to fully evaluate their success. Different jurisdictions have different standards which are difficult to compare or benchmark. The AER has the ability to introduce a consistent national service incentive scheme for electricity distribution based on experience gained from regulating the jurisdictional schemes.

54	What is an appropriate governance structure for setting and monitoring reliability standards and what is the rationale or evidence base for different standards across jurisdictions?	Development of a governance structure for setting and monitoring reliability standards is a policy matter to be handled independently of the network businesses. Conceivably, this may involve jurisdictional variations reflecting local conditions.
55	To what degree should a jurisdiction that specifies a higher reliability standard than others justify such a requirement to its constituents based on a transparent cost-benefit analysis?	As per the answer to question 54.
	Demand side management	
56	What role could demand management play in reducing peak demand, how would it work, how much would it cost and what network savings would be experienced? In which parts of the network are costs savings most likely and why?	Demand Management has a role to play. The AEMC is addressing the opportunities for Demand Side Management as part of its current Power of Choice Review (see http://www.aemc.gov.au/market-reviews/open/stage-3-demand-side-participation-review-facilitating-consumer-choices-and-energy-efficiency.html). Should the Productivity Commission wish, the ENA will be able to make available its submission to the AEMC once lodged by with the AEMC by 4 May 2012.
57	What are the regulatory and other obstacles to demand management or other approaches that give consumers choice? How are these changing?	Please see the response to question 56 above.

58	How do network providers model and make financial decisions about the impact of peak demand growth on network adequacy including identification of the most cost-effective network investment solution (for a given reliability standard)?	It is not possible to capture the specific approaches used by each network business to address these issues in a single answer given the time available to respond. The ENA would be happy to provide further information on this topic if requested.
59	How could benchmarking or other tools identify the degree to which network businesses have efficiently used demand-side management as substitutes for building redundancy in their networks?	Please see the response to Q 56 above.
60	What is the evidence about the effectiveness and customer acceptance of demand management provided by the various trials and experiments in Australia and internationally? What factors have inhibited the use of already installed smart meters?	Please see the response to Q 56 above.
6	**Interconnector issues**	
61	To what degree are interconnectors important to greater competition and greater efficiency in the NEM (once account is taken of the costs of construction and any collateral investments required)?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.

62	What is the magnitude of the impacts on prices, generator capacity and the use of renewable power arising from any deficiencies in interconnector investment? In effect, do flaws matter much?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
63	What empirical methods could be used to indicate the scope for further interconnectors?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
64	What are the obstacles to efficient interconnector investment and could these be overcome?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
65	Are current co-ordination and planning arrangements efficient?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
66	If more interconnection is efficient, how much and where would the additional capacity be built?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
67	Why should regulations for transmission and distribution investment be different?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.

68	What are the advantages and disadvantages associated with various options to improve interconnector efficiency, taking into account that some potential solutions (such as public contest methods) may have far-reaching impacts on other parts of the market? What changes in distribution and transmission regulation would be required to permit more market-based interconnector arrangements?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
69	To what extent is it likely that prospective upgrades in interconnection capacity will resolve the currently perceived problems without a need for policy changes? Are longer-term policy changes required to ensure longer-term upgrades?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
70	Will the value of greater interconnector capacity rise as carbon pricing creates larger cost margins between competing generators located in different states? If so, to what extent?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
71	Given the AEMC's ongoing review of the transmission framework, where can the [Productivity] Commission add the most value to interconnector policy issues?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.

72	What are the lessons from other countries' approaches to interconnector investment, including the Argentinian approaches and the new cost allocation principles of the US FERC (Order 1000) released in July 2011?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
73	Taking account of the costs of interconnectors and their transmission losses, to what extent could congestion and price separation events be better addressed by alternatives, such as more investment in transporting gas to gas-fired generators or by using distributed generation? Are there barriers to such alternatives?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
7	**The role of generators**	
74	To what degree does the type, location and conduct of generators affect the efficiency of the electricity network? What are the implications of any such impact?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
75	How would benchmarking of network businesses or its application in regulations take into account any such complexities?	The ENA notes that GridAustralia intends to respond to this question in its separate submission.
8	**Accounting for the future**	

76	What are trends in electricity supply and how will these affect regulation, and the need for and use of, benchmarking and other regulations?	This is a broad question and difficult to answer effectively within the scope of the inquiry. However, it is envisaged that benchmarking will remain an important part of the regulatory toolkit for the foreseeable future. What is essential is that • the nature of the benchmarking and the way it is carried out be appropriate; and • it operate as an effective part of the overall incentive-based regulatory framework. Both these dimensions are addressed in the body of the submission.
77	To what extent, if at all, will renewable generation and household feed-in tariffs require network upgrades? How costly and efficient would it be?	All forms of new generation and load have potentially significant operating and cost implications for the network(s). How those costs are best allocated between the specific party, the remaining network customers and the broader community is a complex policy question beyond the ability of the ENA to address within the time allowed for responding to the Issues paper.
78	Is local small-scale power generation likely to develop cost-effectively to such a degree that it: (a) erodes the distribution network natural monopoly; (b) significantly reduces network investment requirements? If so, how long before this happens, with what technologies and costs and with what implications for regulation? Are there obstacles to efficient distributed generation?	This is problematic to answer given the range of wider variables at play including technological developments, the broader investment climate and range of relevant government policies.
79	How fast will Australia move towards 'smart grids'? How much will these cost and what impacts will they have on reliability and overall network investment? Will they provide better evidence about the comparative performance of different network providers?	See answer to question 78.

80	To what degree could the likely future development of better benchmarking tools be incorporated into current incentive regulations to reduce any bias towards excessive investment? How should any such incentive regulations be designed? What are the major advantages and disadvantages of such incentive arrangements and, in particular, the magnitude of any risks that such an approach could chill efficient investment? Are there any similar arrangements in utilities or other regulations that provide lessons on such incentive arrangements?	As previously noted, the AEMC is currently assessing whether changes should be made to the regulatory framework on the basis of the AER and EURCC's Rule change proposals. The way in which the AER may undertake benchmarking as part of a revenue assessment has not been raised as a specific issue by those parties. However, the ENA notes that: • the Rule change process is the appropriate mechanism for proposing improvements to benchmarking (if not part of the current assessment, then by way of future proposals); and • as per the answer to question 76, any proposal for improvement would need to balance efficient prices for customers with the need for effective investment certainty and clearly demonstrate net benefits in this regard.
9	**Implementation issues**	
81	How should policy change be implemented, what are the priorities and how long will it take? Is there a critical sequence of changes that should take place?	Any policy change would need to recognise that AER revenue determinations for distribution and transmission businesses are processed on a 5 year cycle and that the timing of those determinations varies across the NEM.
82	Are there significant costs in implementing change?	The costs for implementing change are dependent upon the change and can vary from small to large.
83	Which agencies/parties should do what when implementing change?	Changes to the Electricity and Gas rules would need to be approved through the Rule change process managed by the AEMC. The AER would then be responsible for implementation of any new rules.
84	Is there any interaction with other policies/regulations that would affect the effectiveness of implementation?	This is possible depending on the nature of the proposed changes.

85	Given the experience of the last five to 10 years, over the longer term, how should the NEM be modified to meet the best interests of consumers?	The NEM and its associated frameworks are the result of government led reforms over the last twenty years. Those reforms have delivered a range of economic benefits to the wider community. Consistent with the provisions of the National Electricity Law, further reforms would need to provide a balance between efficient prices for customers and effective investment incentives for energy businesses and only be made when it is clear that there is a net overall benefit from the relevant change. Where opportunities for change in the best interests of consumers have been identified these are generally given effect via the AEMC Rule change process, which applies the National Electricity Objective as the Rule making test. This Objective has, as its centre piece, the long term interests of consumers.